INTEGRATED RESOURCE PLAN

2020

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PG&E®

PACIFIC GAS AND ELECTRIC COMPANY

2020 INTEGRATED RESOURCE PLAN

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a. Introduction

The Pacific Gas and Electric Company (PG&E) is pleased to participate in the Integrated Resource Planning (IRP) process and help shape California's future energy resource mix to meet the state's clean energy goals in a reliable and cost-effective manner. PG&E is one of the largest combined natural gas and electric energy companies in the United States. PG&E delivers some of the nation's cleanest energy to nearly 16 million people—or one in 20 Americans—throughout a 70,000-square-mile service area in Northern and Central California. PG&E's service area stretches from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada in the east. PG&E provides electric service to more than 5 million electric customer accounts.

Through the IRP, California has the potential to transition away from the specific and siloed resource mandates of the past towards a true least-cost approach to meeting the state's greenhouse gas (GHG) emissions reduction goals in a reliable manner. This transition is critical to the sustainability of California's climate policies and the state's continued environmental leadership. PG&E recognizes that the 2019–2020 IRP cycle builds upon the experiences of the inaugural 2017–2018 cycle, while the IRP framework is being further enhanced and refined through the IRP Order Instituting Rulemaking (OIR), R.20-05-003. Through these efforts, PG&E looks forward to helping to make the integrated planning vision set forth in Senate Bill (SB) 350 a reality. However, more work is needed to realize that vision.

Following the filing of plans by load-serving entities (LSEs) in 2018, the 2018 IRP Preferred System Plan (PSP) did not identify a need for additional resources for system reliability (D.19-04-040). Yet within months of this determination and outside the designed structure of the IRP process, the California Public Utilities Commission (CPUC or Commission) concluded that there was a significant need for additional system RA (Resource Adequacy) and ordered procurement of over 3,300 MW of new capacity as part of the 2019 IRP Procurement Track (D.19-11-016) assigned solely on load share and without regard to the needs of individual LSEs. Better alignment among the PSP, system reliability needs, and any procurement mandate for individual LSEs is vital to continued development of a robust IRP process.

A similar reliability concern exists for this 2019–2020 IRP cycle. Before the conclusion of the current IRP cycle, the Commission—in collaboration with the California Independent System Operator (CAISO)—should confirm that the aggregated LSE plans include sufficient resources to support system reliability and the reliability impacts of any change in the GHG emissions planning target are well understood.

b. Recommendation for IRP Process Improvement

Reliability Analysis

This second IRP cycle represents an opportunity for the LSEs, the CAISO, and the Commission to work together to produce a reliable and cost-effective plan that addresses California's energy resource needs and emissions goals. It is critical that any procurement resulting from the IRP be based on the resources and need documented in LSE plans and an assessment by the CAISO to confirm that the amount and the type of resources identified in the IRP process are sufficient to meet the CAISO's operational reliability needs (both at the system and local levels).

At a minimum, before completion of the current IRP process, the Commission must perform a robust reliability analysis with opportunities for stakeholders to review.[1] The analysis should be performed at the system level and should include an assessment of whether OTC replacement resources are needed in local areas (as defined by the CAISO)[2] or at the sub-regional level due to transmission limitations (e.g., Path 26 rating).

The recent rolling blackout events of August 14–15, 2020,[3] clearly demonstrate a need for an operational reliability assessment[4] to confirm that the planned resources from the IRP process will be sufficient to address operational reliability needs. It is crucial that a robust reliability assessment is completed before the Commission considers a lower GHG emission target for 2030. This assessment should include the CAISO's participation to clearly identify additional transmission and renewable integration investments needed to maintain operational reliability. Given that the 46 Million Metric Tons (MMT) planning target is within CARB's 2030 range for the electric sector emissions to support the state's 2045 SB 100 zero-emissions goals,

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[1] PG&E has offered specific recommendations on how to refine the reliability framework to ensure reliability is assessed in an adequate manner. *See, e.g.*, "Opening Comments of Pacific Gas and Electric Company (U 39E) On Ruling Of Assigned Commissioner And Administrative Law Judge Seeking Comment On Policy Issues And Options Related To Reliability," dated December 20, 2018.

[2] Local areas within the CAISO Balancing Authority Area that have limited import capability and require minimum generation capacity to mitigate the local reliability problems in those areas. http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx.

[3] Reference: CAISO Press release dated 08/15/2020: http://www.caiso.com/Documents/ISORequestedPowerOutagesFollowingStage3EmergencyDeclarationSystemNowBeingRestored.pdf.

[4] An operational reliability assessment would consider whether the CAISO system has sufficient resources to meet demand under normal and outage conditions and whether the system has sufficient inertia and frequency response capability to maintain system frequency within acceptable limits.

the Commission should be certain of the potential reliability and cost implications before adopting a lower GHG emissions target.[5]

Procurement Requirement Allocation Methodology

The Commission also should use a stakeholder-driven process to develop a procurement requirement allocation methodology for assignment of any incremental procurement (beyond what is already planned by the LSEs) to ensure that the allocation is based on LSE need and not simply on load share.

A large and growing number of LSEs increases the complexity of the IRP process. California's expansion of retail choice—driven by growth in distributed generation (DG), the expansion of Community Choice Aggregators (CCAs), and the potential for Direct Access (DA) reopening—add considerable fragmentation to long-term electric sector planning. The inclusion of many more LSEs into the planning process creates challenges that did not exist just a few years ago. More work is needed to fairly allocate procurement obligations across a large set of LSEs and to address barriers to procuring large, capital-intensive resources across a fragmented marketplace.

Coordination with Other Commission Initiatives

The regulatory environment is changing as well, furthering the uncertainty in the planning horizon. Ongoing Commission proceedings, such as the Power Charge Indifference Adjustment (PCIA) OIR and the RA OIR, are considering fundamental changes to the ways LSEs operate and the ways in which costs and benefits are allocated across customers served by different LSEs. The Integration of Distributed Energy Resources (IDER) proceeding (R.14-10-003) also has adopted policies to better align the valuation of distributed energy resources with supply-side resources, though modelling challenges remain. Further still, other proceedings will be affected by the outcome of the IRP itself. Consequently, the Commission, LSEs, and others must continue to work together to align the various proceedings to help the state achieve its ambitious GHG targets while weighing affordability and reliability challenges.

c. Key Takeaways from PG&E's IRP

Against this backdrop of a changing market and regulatory environment, PG&E evaluated its bundled portfolio needs through the lens of our key objective: to safely and reliably deliver affordable and clean energy to our customers and communities while building the energy network of the future. Within the planning parameters established for the IRP, we considered our current bundled portfolio resources and capabilities, our bundled load forecast, and our share of the 2030 GHG emissions benchmark, alongside our goal of benefiting our customers through innovation with a priority on disadvantaged communities.

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[5] D.20-03-028, Finding of Fact 11.

Key takeaways include:

- PG&E's bundled electric service portfolio has no incremental procurement need beyond already-planned mandated procurement to meet its Renewables Portfolio Standard (RPS) or GHG requirements through 2030 for the Commission's adopted 46 MMT GHG target for 2030.
- If the Commission adopts a 38 MMT GHG target for 2030, PG&E's portfolio will need an incremental 748 MW of wind resources beyond its already planned procurement to meet its 2030 GHG emissions benchmark.
- Critically, before committing to a lower GHG target, the Commission and stakeholders should have a clear understanding of the reliability and cost implications. The work done so far does not address these questions sufficiently. In particular, PG&E is concerned that the results of the rate analysis fail to fully capture the investments needed in the transmission and distribution system and for renewable integration to reliably operate the system.
- PG&E is not seeking additional procurement authorization in this IRP for GHG-free resources due to the longer-term timing of the need and a number of nearer-term uncertainties on which PG&E expects more clarity soon, including future load departure and the outcome from the PCIA Working Group 3 (WG3) activities.
- In both the 46 and 38 MMT scenarios, PG&E shows a peak month need for system RA beginning in 2025 based on the Commission's IRP RA calculator. For the IRP plan, PG&E anticipates meeting this modest RA deficiency through future market transactions from available resources and/or system RA allocations from Central Procurement Entity (CPE) transactions. PG&E does not presently intend to seek procurement authorization for such capacity in the near term. PG&E's plans may change if further reliability analysis by the Commission demonstrates an increased need for system capacity.[6]
- PG&E's analysis indicates that the Commission's Resource Sufficiency calculation over-allocates responsibility for system RA capacity to PG&E. In its IRP submittal, PG&E corrects this misallocation, resulting in a more accurate RA capacity assessment. The Commission should account for this misallocation when evaluating LSE plans.
- Given that certain resources exiting PG&E's bundled portfolio in the near term are likely to be procured by the CPE in future years, the Commission should avoid mandating that LSEs procure resources that are expected to be addressed by the CPE.
- If the Commission determines that there is an RA capacity procurement need, the allocation of procurement should be based on individual LSE needs after a more robust, transparent system RA determination process—*not based on load share*.

[6] PG&E's plan does not reflect possible reliability requirement changes that the Commission may order in response to the August 2020 rolling blackout events.

- Depending on the outcome of PCIA WG3 (portfolio optimization/allocation), PG&E may seek procurement authorization from the Commission for execution of additional procurement prior to filing its next IRP.
- If a future procurement need is identified, PG&E will meet its bundled portfolio needs through all-source Requests for Offers (RFOs). Resource procurement would be based on least-cost, best fit to meet the identified need based on then-current technologies, capabilities, and market information.

d. Study Design

PG&E developed two Conforming Portfolios for its IRP: A Conforming Portfolio to meet a 46 MMT 2030 GHG statewide planning target and a Conforming Portfolio to meet a 38 MMT 2030 GHG statewide planning target. Each of the Conforming Scenarios were tested against PG&E's RPS compliance requirements, the IRP's LSE GHG benchmark (measured using the Clean System Power (CSP) Tool), and other key bundled portfolio requirements such as system RA needs, to determine the need for any incremental resources and, if needed, which type. The analysis includes three key assumptions: (1) continuation of existing procurement mandates; (2) GHG-free energy sales similar to 2020 for the remainder of the planning horizon; and (3) as directed by the Commission, the analysis did not include any resource allocation that may result from PCIA WG3.[7]

e. GHG Emission Results

For the 46 MMT Conforming Scenario, no incremental GHG-free procurement is needed through 2030. For the 46 MMT scenario, PG&E's 2030 forecasted portfolio emission is 4.543 MMT. This value is below PG&E's 2030 GHG emissions benchmark of 4.737 MMT. The GHG benchmark is met with the existing portfolio and future procurement already mandated or authorized by the Commission.

For the 38 MMT Conforming Scenario, PG&E would need to procure 748 MW of incremental wind generation by 2030 in order to bring forecasted GHG emissions below its GHG emissions benchmark after accounting for PG&E's existing RPS and GHG-free resources, anticipated RPS and Carbon-Free sales transactions, and forecasted procurement from the CPUC's mandated procurement program. For the 38 MMT scenario, with the addition of 748 MW of wind resources PG&E meets its 2030 GHG benchmark of 3.784 MMT. Otherwise, the 38 MMT Conforming Scenario portfolio is identical to the 46 MMT Conforming Scenario portfolio.

[7] R.20-05-003, *Filing Requirements' Questions and Answers*, Q&A #22, dated August 8, 2020.

f. Local Air Pollutant Minimization and Disadvantaged Communities

PG&E applauds the Commission's efforts to establish a standardized framework to evaluate air pollutant emissions ($PM_{2.5}$, SOx, and NOx) and to address emission impacts in Disadvantaged Communities (DACs).

PG&E is engaged in a comprehensive set of activities to benefit low-income customers and customers in DACs, including targeted DAC-focused programs for clean transportation charging infrastructure, energy efficiency (EE), distributed solar, energy storage, demand response, and low-income support programs such as California Alternative Rates for Energy, Family Electric Rate Assistance (FERA), and Energy Savings Assistance (ESA).

PG&E is not proposing any new gas fired power plants in this IRP and does not anticipate a need for future long-term contracts with these facilities. Nevertheless, the IRP process should account for the likelihood that these resources may continue to be needed (e.g., for local reliability) even if they are no longer part of PG&E's bundled portfolio.

Looking ahead, it is crucial that the state not limit its consideration of $PM_{2.5}$, SOx, and NOx emissions to the electric sector. Fossil power plants emit only 2 to 4 percent of statewide NOx emissions and only 1 to 2 percent of statewide $PM_{2.5}$ emissions, while the transportation sector is responsible for 60 to 75 percent of statewide NOx emissions and 12 to 22 percent of statewide $PM_{2.5}$ emissions. PG&E strongly supports a more comprehensive, multi-sector effort to tackle California's air pollution challenges. PG&E supports the statewide air pollution reduction program based on Assembly Bill (AB) 617 and is actively considering how to best facilitate the growth of electric and low-to-zero emission natural gas and hydrogen vehicles to reduce local air pollutant emissions from the transportation sector.

g. Action Plan

The Action Plan describes PG&E's near-term activities and recommendations for Commission action to support the effective implementation of PG&E's Conforming Scenarios. PG&E will continue to procure RPS resources and energy storage based on existing compliance obligations, including procurement mandated regardless of Investor-Owned Utility (IOU) need. PG&E will continue to offer a suite of demand-side management (DSM) programs and tariffs for EE, DG, and demand response resources, as well as programs for customers located in DACs. PG&E's Action Plan also includes the activities PG&E is engaged in to achieve two million zero-emission vehicles in PG&E's service territory by 2030. Facilitating the growth of clean transportation technologies is a cornerstone of PG&E's strategy to support California's GHG reduction goals and its efforts to reduce local air pollutants with early priority on disadvantaged communities.

h. Diablo Canyon Power Plant Retirement

In April 2020, the Commission approved Standard LSE Plan filing requirements related to DCPP replacement. Per the filing requirements, all LSEs are required to "[p]rovide narrative description explaining which specific resources are planned to be procured to serve their load in the absence of DCPP" and that "new resources are suitable substitutes and are able to maintain system reliability without increasing GHG emissions."[8]

PG&E appreciates the Commission's focus on new resources that are able to maintain system reliability without increasing GHG emissions. PG&E strongly supports efforts to conduct a comprehensive reliability assessment, which would consider the appropriate amount and type of renewable integration needed to reliably replace DCPP. PG&E urges the Commission to carefully review each LSE's IRP to ensure it sufficiently demonstrates how each LSE will meet future reliability and renewable integration needs.

PG&E's analyses for its 46 MMT Conforming Scenario indicates that, after Unit 1 retires in 2024 and Unit 2 retires in 2025, PG&E is projected to have sufficient GHG-free resources in its bundled electric portfolio such that the GHG emissions benchmark for PG&E's bundled electric portfolio would be met through 2030. Similarly, for its 38 MMT Conforming Scenario, with the planning addition of 748 MW of GHG-free resources by 2030, PG&E will meet its GHG emissions benchmark.

Additionally, PG&E continues to support reliability through its planned procurement, including dispatchable batteries which will aid in renewable integration and reliability. PG&E's 2030 planned portfolio provides 52 percent of its September RA requirement from flexible resources, including hydroelectric, pumped storage, and battery storage.

i. Lessons Learned

As PG&E developed its IRP LSE Plan filing, tests of the Commission's RSP using the RESOLVE model revealed the model's sensitivity to key inputs, including out-of-state (OOS) import capability and hydro resource capacity factors. Significantly different resource builds result from relatively modest input assumption changes, particularly regarding these two key modeling assumptions. More attention and analysis need to be given to these critical assumptions.

Similarly, PG&E notes that the Commission's Reference System Plan does not effectively account for fossil plant retirements—retiring 30 MW of peaker fossil plants while retaining all other fossil resources, including Combined Heat and Power (CHP) resources, in the 46 MMT case. The IRP should consider more realistic fossil retirements over the planning horizon.

j. Conclusions

This second IRP cycle, which comes amidst a global health pandemic and significant economic upheaval as well as CAISO-directed rolling blackouts, represents a crucial moment for electricity planning and GHG reduction in California. The IRP process continues to evolve and

[8] IRP Narrative template, p. 14.

adapt to the continued fragmentation of retail electric service, the uncertainties facing long-term planning efforts, and increasing behind the meter (BTM) generation and storage. We urge the Commission to continue to evolve the IRP process to provide the flexibility needed to accommodate future changes in market conditions, customers, and technologies, while keeping a close eye on reliability and affordability. Ultimately, developing and implementing a robust IRP process will support continuation of California's visionary leadership in service of a clean, reliable, and affordable energy future for all customers.

II. Study Design

This section of PG&E's Plan describes how PG&E developed its LSE Plan and includes the following components of PG&E's analysis:

- Objectives for the analytical work presented in the filing and scenarios included in PG&E's Plan
- Description of the study methodology including tools and approaches used in developing PG&E's scenario analysis.

a. Objectives

PG&E's key objectives for its IRP align with the customer-focused mission that drives all our activities: to safely and reliably deliver affordable and clean energy to our customers and communities every single day, while building the energy network of tomorrow. PG&E's IRP analysis specifically focuses on the following key objectives:

- **Clean energy:** For decades PG&E has been a leader in developing clean energy technologies in California. In 2019, PG&E delivered nearly 30 percent of its electricity from RPS-eligible renewable resources, such as solar, wind, geothermal, biomass, and small hydropower. Additionally, PG&E's GHG-free energy production, which encompasses renewable resources, large hydropower, and nuclear, satisfied all of PG&E's bundled retail sales in 2019.[9] PG&E's IRP analysis is focused on meeting the state's goals for RPS for the planning horizon and PG&E's 2030 GHG planning benchmark.
- **Reliability:** Maintaining system reliability is critical, especially as California transitions towards higher shares of GHG-free generation resources, many of which are intermittent.
- **Affordability:** PG&E's IRP analysis selects resources to meet the state's clean energy and reliability goals in a least-cost manner to customers and provides a system average rate forecast in compliance with the CPUC's requirements for IOUs.

b. Scenarios Considered

PG&E developed two IRP scenarios[10] to address PG&E's proportional share of a 46 MMT 2030 GHG target and its share of a 38 MMT 2030 GHG target. Both scenarios use the CSP Tool, which relies on a GHG emissions benchmark approach.

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[9] http://www.pgecorp.com/corp_responsibility/reports/2020/bu07_renewable_energy.html

[10] Consistent with the CPUC 2020 IRP filing requirement, "[e]ach LSE must produce and submit at least two "Conforming Portfolios:" one that addresses the LSE's proportional share of the 46 MMT GHG target, and another that addresses the LSE's proportional share of a 38 MMT target." Narrative Template Overview, dated June 15, 2020, at p. 4.

The IRP scenarios developed by PG&E are summarized in Table 1, below.

TABLE 1
PG&E'S IRP SCENARIOS

Line No	Scenario	PG&E Net System Sales (2030)	PG&E Bundled Sales (2030)	PG&E GHG Emissions Benchmark (2030)
1	Conforming Scenario I 46 MMT GHG Case	89,327 GWh	26,777 GWh	4.737 MMT
2	Conforming Scenario II 38 MMT GHG Case	89,327 GWh	26,777 GWh	3.784 MMT

i. Conforming Scenario I, 46 MMT GHG Case

Objective: Meet the filing requirements established by the Commission.

Key Variable(s):

1. 2019 Integrated Energy Policy Report (IEPR) loads utilized per CPUC Filing Requirements; and
2. 46 MMT 2030 GHG Target; CSP Calculator Tool based on 46 MMT GHG target.

For the 46 MMT Conforming Scenario, PG&E developed its portfolio based on the California Energy Commission's (CEC) 2019 IEPR load forecast for PG&E with the further modifications for updated CCA loads as permitted in the January 24, 2020 Administrative Law Judge (ALJ) Ruling.[11] The final 2019 IEPR forecast does not reflect the formation of new CCAs in PG&E's territory after 2020 and does not reflect potential expansion of existing CCAs beyond load growth/decline. PG&E's bundled load is 26,777 GWh in 2030 in this scenario.

For the 46 MMT Conforming Scenario, PG&E' assumptions are consistent with CPUC's RSP assumptions with the following exception:

- For future procurement of mandated program resources not yet in PG&E's bundled electric portfolio,[12] PG&E used its internal cost estimates for those programs derived from program and PG&E commercial data for calculating the revenue requirements.

ii. Conforming Scenario II, 38 MMT GHG Case

Objective: Meet the filing requirements established by the Commission.

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[11] ALJ Ruling Allowing Updated Load Forecasts, R.16-02-007, January 24, 2020.

[12] Includes ReMAT and BioMAT mandated RPS procurement programs. https://pge.accionpower.com/ReMAT/home.asp. https://pgebiomat.accionpower.com/biomat/home.asp.

Key Variable(s):

1. 2019 IEPR loads utilized per CPUC Filing Requirements; and
2. 38 MMT 2030 GHG Target; CSP Calculator Tool based on 38 MMT target.

For the 38 MMT Conforming Scenario, PG&E's assumptions and methodologies were consistent with its approach in developing the 46 MMT Conforming Scenario, albeit using the CSP Tool provided by the Commission for the 38 MMT case. PG&E's bundled load is unchanged (26,777 GWH in 2030) in this scenario.

iii. Other Considerations

This section describes PG&E's assumption for mandated procurement programs and GHG-free sales and includes a discussion of the impact of PCIA WG3 and CPE on future IRPs.

A. Continue Mandated Procurement

PG&E's portfolio reflects continued mandated procurement, including both of the CPUC's mandated small project Renewable Market Adjusting Tariff (ReMAT) and Bioenergy Market Adjusting Tariff (BioMAT) RPS procurement programs. The additions include a diverse mix of technologies such as wind, biogas, and biomass that begin operation by 2030.[13]

B. GHG-free Sales Assumption

Consistent with the Commission's LSE planning requirement that the IOUs retain all of the PCIA-eligible resources in their respective portfolios,[14] PG&E assumes that it will have future GHG-free energy sales based on the Commission adopted Resolution (Res.) E-5046.[15] Res. E-5046 gave LSEs within PG&E's Transmission Access Charge (TAC) area the option to receive a pro rata allocation of the GHG-free attributes associated with PG&E's large hydroelectric and nuclear carbon-free resources for the remainder of 2020. For its 2020 LSE IRP, PG&E assumes that GHG-free energy sales will continue for years 2021–2030, with sale levels that are consistent with the sales executed in 2020 for 2020 deliveries.

C. PCIA Working Group 3

In October 2018, the CPUC adopted modifications to the methodology for calculating the PCIA and ordered a second phase (Phase 2) of the proceeding to enable a diverse group of stakeholders to engage in a working group process to develop proposals to address additional

[13] PG&E's mandated procurement program assumptions do not reflect the recent proposals in R.18-07-003: "Revising the Bioenergy Market Adjusting Tariff Program" and the "Proposed Modifications to the Renewable Market Adjusting Tariff Program."

[14] D.20-03-028, O.P. 8.

[15] This is a planning level assumption and is subject to change in future.

issues identified in Phase 1 of the proceeding. The scope of issues for Phase 2 of the proceeding is for a working group to address three specific issues:

1) (Working Group 1) the benchmarking and true-up of the PCIA based on actual market results;
2) (Working Group 2) an option for DA and CCA customers to prepay their entire future PCIA obligation; and
3) (Working Group 3) portfolio optimization and cost reduction, auction and allocation.

As part of PCIA WG3, a series of workshops culminated in multiple parties submitting portfolio optimization and cost reduction, auction and allocation proposals in Q2 2020 for consideration by the CPUC. The proposals included allocation frameworks for the following attributes of the IOUs' PCIA-eligible portfolios: (1) Local RA, (2) System RA, (3) Flexible RA, (4) Renewable Energy Credits (RECs), (5) GHG-free energy, and (6) GHG-emitting energy (collectively, PCIA-eligible attributes).

All of the proposals include some form of allocation of the PCIA-eligible attributes to all PCIA-eligible load serving entities (LSEs), including the IOUs, but differ in frequency and implementation details. For instance, one proposal would allocate the entire PCIA-eligible portfolio starting with the 2021 delivery year, at the earliest. Another proposal would allocate the entire PCIA-eligible portfolio starting with the 2023 delivery year. A third proposal would allocate the IOUs' excess volumes, namely what is remaining after bundled service customer needs, starting with the 2023 delivery year. For PG&E, the first two proposals could mean allocating a majority of its annual RPS generation and would represent a significantly different approach than what is laid out in this IRP filing. A final decision from the CPUC on WG3 is expected in late 2020, precluding the inclusion of this potentially significant impact on LSEs' IRP bundled portfolios.

Commission staff has indicated that LSEs should not assume outcomes of PCIA WG3 in their IRP filings,[16] and, so, PG&E has not reflected these possible outcomes in its study methodology, design, or results. However, the Commission and parties should appreciate that the outcome of PCIA WG3 likely will have a significant impact on PG&E's and other LSE's portfolio management strategies and needs in the future.

D. Capacity Procurement Entity

Following the CPUC's recent decision in D.20-06-002, PG&E will serve as the CPE that will procure Local RA resources on behalf of all CPUC-jurisdictional LSEs in its TAC service territory area and not solely on behalf of bundled service load. As the CPE structure is implemented, PG&E will function in a dual capacity. The first delivery date for CPE procurement is January 2023 with CPE functions beginning in 2021. For this IRP Plan, PG&E has

[16] D.20-03-028, O.P. 8, directs LSEs to assume PCIA resources stay in their portfolio.

not analyzed its bundled portfolio needs in light of potential allocations from future CPE procurement activities.

Additionally, the CPUC may expand the CPE role beyond its current focus on local capacity needs. PG&E recommends that the IRP process adapt to accommodate the separate procurement functions that LSEs and CPEs perform for both system reliability and local area reliability needs. Specifically, the Commission should determine how system RA and energy procured by the CPE will impact LSE IRP requirements and be reflected in IRP modeling.

c. Methodology

i. Modeling Tools

PG&E has employed several analytic tools in developing its resource plans and in forecasting costs used in the revenue requirement and average bundled rate calculations. The tools fall into two broad categories:

1. CAISO System Tools: used to ascertain the resource buildout and underlying market attributes at the CAISO system level; and
2. Bundled Portfolio Analysis Tools: used to model PG&E's bundled portfolio.

The two sets of tools are linked, as outputs from the CAISO System Tools (e.g., CAISO resource mix) are used as inputs into the Bundled Portfolio Tools. A high-level description of the modeling tools used in the analysis follows below.

A. CAISO System Tools

1. **CPUC's RESOLVE Model:** For the Sensitivity Studies included in the Lessons Learned Section, PG&E used RESOLVE to model capacity expansion at the CAISO level. Using RESOLVE helps ensure consistency across all sensitivities and promotes simple comparisons with the Conforming Scenarios. PG&E relied solely on the capacity expansion results (i.e., system-level resource portfolios) because the commitment and dispatch modeling and the time granularity in RESOLVE are highly simplified. PG&E used its own proprietary models, as described below, that take the RESOLVE capacity expansion results as inputs to develop market price forecasts that are needed for the bundled portfolio assessment.
2. **PG&E's Hourly Power Price Forecast Tool:**[17] This model establishes CAISO hourly power prices as a function of the CAISO system net-load and dispatchable resources available at each hour. Key inputs for this model are the CAISO system-level resource mix forecast, CAISO load and net import levels, all of which come from the specified

[17] Note that this model is PG&E's proprietary model and is used routinely by PG&E as part of its forward curve development process, and variants have been used in past regulatory filings, including in Energy Resource Recovery Account (ERRA) forecast proceedings. A more detailed discussion of the framework underlying this tool can be found in PG&E's 2017 GRC testimony, A. 15-09-001, Chapter 2.

RESOLVE model run. The model also relies on natural gas prices and GHG prices from the April 2019 CEC gas commodity mid-case forecast. The hourly prices are used to calculate the bundled portfolio generation revenue requirements. The hourly prices are also essential inputs to other commodity forecast models (namely, RA and REC price forecasts) required for the generation revenue requirement calculations.

3. **PG&E's Capacity Price Forecast Tool:**[18] This tool forecasts dispatch and imputes a capacity value for RA as a function of a marginal resource's net market revenues and going-forward operating and capital costs for various generation technologies. The tool also incorporates market capacity prices in the short term.
4. **PG&E's REC Price Forecast Tool:**[19] The REC price forecast tool calculates REC forward price by calculating a per-MWh premium for RPS-eligible energy. For example, the REC forward price for a given year, say 2024, for a solar resource is calculated based on the levelized cost of a new solar resource coming online in 2024, minus the levelized market revenue of the new solar resource. The tool also incorporates prices of recent REC transactions in the short term.

B. Bundled Portfolio Analysis Tools

1. **CPUC's CSP Tool:** The CSP Tool is used to quantify PG&E's GHG emissions and local air pollutants associated with serving its bundled load on an hourly basis for PG&E's IRP scenarios. PG&E used the two versions of the CSP Tool that were provided by the Commission in order to analyze its Bundled Portfolio under the 46 MMT and 38 MMT 2030 GHG targets. PG&E also leveraged the hourly load energy shapes for calculating the bundled portfolio generation revenue requirements.
2. **PG&E's Procurement Portfolio Planner (P^3):** This proprietary model developed by PG&E forecasts PG&E's bundled portfolio generation and procurement costs.[20] P^3 includes the bundled portfolio's individual contracts and dispatchable unit characteristics. Market prices and bundled load are exogenous inputs to the model. The model follows an economic dispatch protocol where in each hour the dispatchable units are dispatched against price.
3. **PG&E's Bundled Portfolio Optimization Tool (BPOT):** This proprietary tool determines the optimal mix of new generation and storage resources to be added to the bundled portfolio under scenarios where the existing set of resources is unable to meet certain operational and/or policy constraints. The model uses linear programming to select a mix of new assets from a set of candidate resources thereby yielding the lowest overall portfolio costs. The model is set up to minimize the net present value of portfolio

[18] This is a PG&E-proprietary model.

[19] This is a PG&E-proprietary model.

[20] PG&E has used the P^3 model in a variety of regulatory proceedings including ERRA Forecasts used to set rates.

costs (new resource costs plus spot market transactions) over the forecast horizon subject to meeting the State's annual RPS requirements and the IRP-mandated 2030 LSE GHG planning target. The model utilized the levelized cost of energy (LCOE) for resources from RESOLVE and all related assumptions including inflation rate, levelization period, discount rate, taxes and financing. (See Appendix 1: Bundled Portfolio Optimization Tool for a more detailed description).

ii. Modeling Approach

This section describes PG&E's modeling approach for its Bundled portfolio.

A. Overview

PG&E's 2020 IRP modeling effort is guided by two key modeling principles:

- Adhere to CPUC IRP guidelines; and
- Provide planning insights in meeting study objectives.

PG&E followed these guiding principles to select the most appropriate tools, approaches, and assumptions for this IRP filing.

PG&E used a three-step process described in this section to develop an optimized bundled portfolio for the scenarios considered by PG&E. This process allows PG&E's portfolios to be tested against three requirements:

1. GHG emission planning benchmark established by CPUC
2. California's RPS (Renewable Portfolio Standard) targets
3. PG&E's system capacity needs to meet RA requirements

The three-steps in PG&E's portfolio development process are:

Step 1: Establish Assumptions to Be Used in the Analysis

For each scenario, the first step is to establish assumptions for PG&E bundled and CAISO system loads and market prices to be used in the different scenarios. These assumptions, along with assumptions for CAISO system level resource mix, are required to determine whether PG&E's portfolio meets the desired requirements listed above and to calculate PG&E's bundled portfolio revenue requirements. Certain assumptions have been specified by the Commission as part of the filing requirements.

Step 2: Determine Incremental LSE Resource Needs

Once the assumptions for the analysis have been established, the next step is to test if PG&E's existing and planned portfolio of bundled resources[21] will meet the three portfolio requirements and determine PG&E's incremental resource need.

[21] Includes utility-owned resources, resources with existing contracts, and resources to be added to meet mandates.

Step 3: As Necessary, Acquire Least-Cost New Resources

If Step 2 above shows a need for additional resources—for instance, to meet the GHG planning benchmark—then an additional step is taken to determine the optimal portfolio to fulfill such need. Functionally, this step resembles the capacity expansion process performed by Energy Division staff and E3 to establish the RSP for the CAISO system, but this step is employed for PG&E's bundled customers only.

B. Modeling Process Details

This section includes a more detailed description of the modeling processes underlying the three-step approach described above. It also provides additional discussion on the reasons behind specific modeling approaches.

Step 1: Establish Assumptions to Be Used in the Analysis

There are multiple sub-steps to develop assumptions to be used in subsequent steps and to calculate the rate forecast:

a) *Establish Bundled Load Forecast* – As discussed in the previous section, for the Conforming Scenarios, PG&E used the CPUC's prescribed load forecast for PG&E bundled customers.
b) *Establish Price Inputs* – Price inputs are used for developing hourly energy, REC, and RA prices. PG&E aligned price assumptions with RSP assumptions or assumptions from the CEC 2019 IEPR.
    1. Natural Gas and GHG Allowances – To develop the hourly energy prices for the Conforming Scenarios, PG&E used the 2019 IEPR natural gas and GHG price forecasts.
    2. Technology Cost – For developing REC prices, PG&E used LCOE forecasts for different technologies from the CPUC's RSP RESOLVE model.
c) *Develop CAISO System Portfolio* – For PG&E's Conforming Scenarios, this is simply the CPUC's RSP.
d) *Develop Energy Prices* – Since RESOLVE does not provide 8,760 hourly market energy prices, PG&E's Hourly Power Price Forecast Tool was used to develop hourly energy prices required to perform revenue requirement and rate calculations. Inputs to this model include CAISO load, the CAISO system portfolio, and natural gas and GHG prices.[22] These hourly energy prices are integral to calculating the bundled portfolio generation revenue requirement for energy market sales or purchases. They are also

[22] PG&E uses this tool routinely as part of its forward price curve development process. A more detailed discussion of the framework underlying this tool can be found in PG&E's 2017 GRC testimony (A.15-09-001).

an essential input to other commodity forecast models required for producing the capacity and REC price forecasts discussed below.

e) *Develop Capacity Prices* – PG&E developed capacity price forecasts using PG&E's Capacity Price Forecast Tool. This tool, as described above, estimates capacity prices based on whether a system has a sufficient capacity buffer above its Planning Reserve Margin (PRM) requirement. For a system with sufficient capacity margin above PRM, the tool calculates capacity prices based on the short run cost of maintaining existing resources. Otherwise, it calculates prices based on the long run cost of acquiring new resources.

   In PG&E's scenario analysis, the CAISO systems produced by RESOLVE had sufficient capacity margins across the planning horizon.[23] As a result, PG&E calculated capacity prices based on the short run cost of existing resources. Specifically, capacity prices are calculated as the minimum payment necessary to cover an existing resource's going-forward costs after considering potential energy market revenues. The market revenues are derived from the energy price forecasts described above. Thus, PG&E's capacity price forecasts reflect PG&E's scenario-specific energy price forecasts.

f) *Develop REC Prices* – REC prices are calculated as the difference between the levelized technology cost paid to acquire a new resource and the resource's estimated market revenue. Consequently, technology cost and market revenue are the largest determinants of the forecasted REC prices. For PG&E's Conforming Scenarios, REC prices were derived using the technology costs from RESOLVE and revenues based on Conforming Scenario prices.

<u>Step 2: Determine Incremental LSE Resource Needs</u>

For PG&E's Conforming Scenarios, PG&E modeled its bundled supply portfolio based on its latest data on existing contracts, future procurement for existing mandated programs, and planned power purchase agreement (PPA) expirations (e.g., CHP) and utility-owned generation (UOG) (e.g., DCPP) resource retirements to determine PG&E's additional resource need, if any.[24]

For all scenarios, PG&E included procurement under various CPUC-mandated programs, including energy storage resources for which it has sought approval pursuant to both Resolution E-4909 and the 2019 IRP Procurement Track mandates.

[23] The recent rolling blackout events of August 14-15, 2020 highlight the need for an operational reliability assessment and consideration of additional or different metric(s) for assessing system reliability given the current resource mix.

[24] For IRP planning purposes, PG&E assumes no recontracting with expiring CHP facilities. This is an IRP planning assumption only.

PG&E then tested the bundled supply portfolio against established requirements (e.g., RPS, GHG, and RA) to determine if there was any incremental resource need.

a) *GHG Emissions:* PG&E's GHG emissions and need for incremental resources were calculated using the CPUC-provided CSP Tool.
b) *RPS Requirement:* PG&E's bundled supply portfolio was tested to identify if additional renewables are needed to meet RPS compliance requirements.
c) *RA Requirement:* PG&E's system RA requirements and need for incremental resources were calculated using the CPUC-provided RDT RA calculator.

Step 3: If Necessary, Acquire Least-Cost New Resources

A bundled portfolio optimization step is triggered if Step 2 identifies a need for additional resources to meet PG&E's GHG planning benchmark or RPS requirements. For its 2020 IRP, PG&E only needed to perform the optimization step for the 38 MMT scenario. Incremental resource additions are not needed for the 46 MMT scenario since the 2030 GHG emissions for PG&E's baseline expected portfolio falls below PG&E's 2030 GHG benchmark. To the extent there was any incremental RA need not met by either PG&E's existing or future expected bundled resources, PG&E determined that such a need could be met through future CPE allocation or RA market procurement.[25]

iii. Revenue Requirement and Rates Modeling

PG&E developed its revenue requirement and System Average Bundled Rates (SABR) for the Conforming Scenarios utilizing the 2019 IEPR sales forecast as the baseline, consistent with the guidance provided in the March 26, 2020 Commission Decision adopting ALJ Ruling.[26] Only generation varied by scenario. The baseline revenue requirement forecast includes the following components:

Distribution (D)

- Forecast years 2020 through 2022 reflect PG&E's pending 2020 General Rate Case (GRC) settlement. Subsequent years escalate the prior year's base revenue requirement using an escalation factor of approximately 4 percent, which is based on the growth of the GRC distribution revenue requirement in the 2017 GRC and 2020 GRC settlement. In addition to the GRC base revenue requirement, the distribution revenue requirement reflects incremental revenue requirements for Electric Vehicle (EV) infrastructure, California Solar Initiative (CSI) (2020–2021), Self Generation Incentive Program, Alternative-Fuel Vehicle, Customer EE Shareholder Incentive,

[25] PG&E's plan does not reflect possible reliability requirement changes that the Commission may order in response to the August 2020 rolling blackout events.

[26] D.20-03-028, *2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning*.

Catastrophic Event Memorandum Account (2020–2022), CPUC Fee, FERA, Mobile Home Park investments, Hazardous Substance Mechanism, Wildfire Mitigation Cost Recovery (2020–2022), and Microgrids (2022–2024).

Transmission (T)

- The transmission revenue requirement includes the currently effective Transmission Owner (TO) base revenue requirement for 2020 and as filed in PG&E's TO20 Rate Year 2021 filing for the year 2021. Beyond 2021, the TO revenue requirement escalates by approximately 5 percent per year. In addition, the adjustments for the Federal Regulatory Energy Commission (FERC)-jurisdictional balancing accounts are also included in the transmission revenue requirement: (1) Reliability Services Balancing Account (RSBA), (2) Transmission Revenue Balancing Account (TRBA), and (3) Transmission Access Charge Balancing Account (TACBA).

DSM Programs

- The DSM Programs' revenue requirements include DR, EE, and DSM Programs.

Generation (G)

- PG&E's bundled customer generation revenue requirement is comprised of the expected bundled customer share of the forecasted cost recovery mechanisms for supply resources and the forecasted Energy Resource Recovery Account (ERRA) costs. The supply resource cost recovery mechanisms include the Cost Allocation Mechanism (CAM), Ongoing Competition Transition Charge (CTC), PCIA, and Tree Mortality Non-bypassable Charge (TMNBC). ERRA costs are primarily comprised of energy and related product purchases from the CAISO, retained RA and REC purchases from CTC and PCIA generation resources, excess RPS sales revenues, and residual RA transactions. RA, REC, and CAISO market energy price assumptions are consistent with the RSPs described above. Further details regarding each revenue requirement can be found in PG&E's 2021 ERRA Forecast application.[27]
- As specified in the IRP filing requirements, the generation revenue requirement also includes the forecasted bundled customer share of electric distribution utility (EDU) carbon allowance auction revenues as an offset to the forecasted generation procurement costs. PG&E's forecast of these revenues is based on PG&E's specified annual allowance allocations in California's Code of Regulations[28] and carbon prices from the 2019 IEPR mid demand scenario.

[27] See A.20-07-002.

[28] See Section 95892, Table 9-4.

Other

- The revenue requirements included in the Other category are: (1) the Public Purpose Programs, excluding those considered EE, DR, DSM, or TMNBC, (2) DWR Bond (which expires in 2020), (3) Wildfire Fund Charge, and (4) Nuclear Decommissioning. The Wildfire Fund Charge begins in 2020 at the same level as the expiring DWR Bond.

The non-generation revenue requirement forecast, comprised of Distribution, Transmission, DSM Programs, and Other is paired with the 2019 IEPR scenario's load forecast to derive the System Average Delivery Rate (SADR).[29] The SADR includes all non-Generation rate components and thus applies to all system sales independent of customers' choice of PG&E or third party supplier. The remaining costs are reflected in the Generation/Commodity revenue requirement and rate, which include the scenario-specific planning assumptions for market price forecasts and for market sales or purchases.

For the generation costs of the Conforming Scenarios, PG&E relied on the Commission's planning assumptions to develop price assumptions used for market purchases or sales. The Conforming Scenarios use PCIA revenue forecasts that assume market-based valuation of the portfolio's attributes, which reduces cost shifts to bundled customers.

The SABR was determined using a two-step process. First, the sum of the revenue requirements for all non-generation rate components applicable to all customers was divided by PG&E's forecasted total system sales for the respective year to determine the SADR. Second, the forecasted bundled share of generation revenue requirements was divided by PG&E bundled sales to determine bundled customers' Generation Rate.[30] The SADR and the Generation rate are summed to determine the SABR.

iv. GHG Emissions and Local Air Pollutants

PG&E relied on the CSP Calculator to model GHG emissions and local air pollutants from its bundled portfolio. In accordance with the ALJ Decision issued April 15, 2020, PG&E's LSE-specific 2030 GHG emissions benchmarks are 5.479 MMT and 4.526 MMT for the 46 MMT and 38 MMT scenarios, respectively.[31] While this ruling finalized the total emissions requirement for each LSE, per the CPUC, it did not account for BTM CHP emissions. In the June 15, 2020

[29] SADR does not include non-bypassable charges recovered through CTC, PCIA, or CAM rates, to which a majority of customers in PG&E's service territory are subject.

[30] Forecasted bundled share based on the bundled sales percent of the applicable total sales for each cost recovery mechanism.

[31] See *Administrative Law Judge's Ruling Finalizing Load Forecasts and Greenhouse Gas Benchmarks For Individual 2020 Integrated Resource Plan Filings and Assigning Procurement Obligations Pursuant To Decision 19-11-016*, dated April 15, 2020 ("April 15 ALJ Ruling").

update to the CSP Calculator and associated CSP Calculator Documentation file, [32] the CPUC clarified that neither emissions from, nor demand met by this type of resource is included in the CSP tool. To account for BTM CHP emissions, the CPUC made an allocation based on a combination of California Air Resources Board (CARB) emission allocations to each IOU Service territory and LSE load share. This was prescribed in the form of a more stringent GHG emissions benchmark laid out in the CSP Calculator files. Consequently, the updated GHG benchmarks for PG&E are 4.737 MMT and 3.784 MMT for the 46 MMT and 38 MMT scenarios respectively.

The CPUC's CSP calculator is also used to determine the emissions levels of three criteria pollutants for PG&E over the planning horizon. The pollutants included in the tool are $PM_{2.5}$, SO_x and NO_x. Though no formal requirement was mandated by the CPUC, the emissions levels of each of these pollutants from PG&E's portfolio are provided in the Study Results section of this filing.

v. System Reliability

PG&E relied on the RDT system reliability calculator to calculate the net system RA positions for its bundled portfolio. As detailed in the System Reliability Analysis section, PG&E identified two adjustments that needed to be made to the RDT to more accurately determine an LSE's system RA position. These adjustments include modifying the calculation for determining an LSE's annual system RA requirement and the net qualifying capacity (NQC) for hydroelectric resources.

While it is important that individual LSEs demonstrate compliance with existing RA requirements, simply demonstrating compliance with existing requirements may not be sufficient to confirm system reliability. PG&E therefore encourages the Commission determine whether new or different metrics should be used for assessing system reliability given the current resource mix.

[32] ftp://ftp.cpuc.ca.gov/energy/modeling/Clean%20System%20Power%20Calculator%20Documentation.pdf.

III. Study Results

Overall, PG&E does not expect it will need to procure new incremental resources, beyond its current mandated procurement, in order to meet its GHG emissions benchmark of 4.737 MMT for the 46 MMT scenario. For IRP planning purposes, PG&E has an incremental need for 748 MW of new resource additions to meet its GHG emissions benchmark of 3.784 MMT[33] for the 38 MMT scenario. In addition, the RPS requirement can be met with generation from PG&E's forecasted bundled RPS-eligible resources. The use of banked RECs from prior years' excess RPS-eligible resource procurement would not be needed to meet RPS compliance until after 2030. The primary reason for the lack of new incremental resource need is load shift to CCAs.

In the following subsections, PG&E presents its portfolio results for the following areas: (1) 46 and 38 MMT Scenario Portfolios, (2) GHG Emissions, (3) Local Air Pollutants and DACs, (4) Cost and Rate Analysis, (5) System Reliability Analysis, (6) Hydro Generation Risk Management, and (7) Resource Development.

a. Conforming 46 MMT Scenario and 38 MMT Scenario Portfolios

i. Energy Sales Forecast

PG&E used a combination of IEPR and ERRA forecasted load and load modifier quantities throughout the study results section in order to complete our analysis. Pursuant to Commission guidance, the scenarios use the 2019 IEPR load forecasts, as modified in the ALJ's April 15, 2020 Ruling adopting revised CCA load forecasts for the purpose of GHG and other criteria pollutant emissions calculations. For PG&E's Cost and Rate Analysis in Section D of the study results, the Commission-approved 2020 ERRA Forecast in D.20-02-047 was used.[34] As shown in Table 2, the bundled customer sales forecast for PG&E is expected to decline by approximately 25 percent from 2020 to 2030 primarily as a result of DA and CCA load departure.

PG&E Unmodified Bundled Customer Demand represents PG&E's bundled sales forecast prior to adjusting for EE, DG, EVs, and electrification. PG&E's Bundled Sales represent PG&E's

[33] See PG&E's Bundled Portfolio Optimization Tool (BPOT) description under the Methodology section or Appendix 1: Bundled Portfolio Optimization Tool for details on the methodology for determining the optimal mix of new generation and storage resources to be added to the bundled portfolio under scenarios where the existing set of resources is unable to meet certain operational and/or policy constraints.

[34] The 2020 forecast for loads, supply resources, and costs is based on the Commission-approved 2020 ERRA Forecast in D.20-02-047 to maintain consistency between PG&E's most recently approved ERRA Forecast and its 2020 IRP forecasts. For all other years of the Conforming scenario, load is based on the 2019 IEPR load. See April 15th ALJ Ruling Table 1 Attachment A located here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M333/K160/333160852.PDF.

sales forecast after accounting for those load modifiers. PG&E Net System sales represent PG&E's total service territory sales after accounting for DA (including BART) and CCA load.

Table 2 shows that expected increases in EE and DG photovoltaic (PV) offset the sales increase driven by economic and population growth and EV demand. This results in Net System Sales for PG&E's service area decreasing slightly from 2020 to 2030.

TABLE 2
CONFORMING SCENARIOS ENERGY SALES FORECAST (GWH)

Line No.	Description	2020[b]	2022	2026	2030
1	**PG&E Unmodified Bundled Customer Demand**	41,218	31,440	32,266	32,634
	Bundled Load Modifiers				
2	Energy Efficiency	[redacted]	(387)	(928)	(1,315)
3	Solar PV	[redacted]	(3,047)	(4,034)	(4,775)
4	Non-PV	[redacted]	(1,680)	(1,670)	(1,643)
5	Total Distribution Generation	[redacted]	(4,727)	(5,703)	(6,418)
6	Electric Vehicles	[redacted]	809	1,310	1,694
7	Building Electrification	[redacted]	0	0	0
8	Other Electrification	[redacted]	54	120	181
9	**PG&E Bundled Sales**	35,945	27,188	27,065	26,777
	Metered PG&E Service Area Demand				
10	Direct Access[e]	9,405	11,780	11,780	11,780
11	Community Choice Aggregation	34,091	37,508	37,546	37,892
12	PG&E Net System Sales	79,440	76,476	76,392	76,449

(a) Totals may not add due to rounding.
(b) 2020 Values come from Commission-approved 2020 ERRA Forecast in D.20-02-047. This results in differences (e.g., EE quantities) in load modifier volumes.
(c) Forecast for load comes from the CPUC-approved modified 2019 IEPR Form 1.1c, finalized in ALJ ruling dated 4/15/2020 and can be found here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M333/K160/333160852.PDF.
(d) All Load modifiers were calculated by the CPUC's CSP tool. Line 4 was not calculated explicitly in the CSP calculator, but followed the same methodology proposed by the CPUC.
(e) Line 10 includes all Direct Access customer demand for 2020 – 2030 and BART for 2022 – 2030.
(f) Lines 2-8 are modified from the CSP calculator to reflect demand at the customer meter.

ii. Resource Additions

PG&E plans to add resources as a result of procurement mandates already authorized by the Commission. This includes resources that have already been contracted and are not yet on-line, and mandated or authorized resources that PG&E had not contracted prior to the submittal of the 2020 IRP. Table 3 summarizes PG&E's resource additions. The amounts shown are total resource capacities, not reflecting any capacity allocations for the CAM. This list does not include investments by customers or third parties in distributed energy resources or investments in EE, which are modeled as load modifiers based on the IEPR forecast values.

TABLE 3
CONFORMING SCENARIOS CUMULATIVE RESOURCE ADDITIONS (MW)

Line No.	Technology	2020	2022	2026	2030
1	Biogas				
2	SB1122/ BioMAT	6	29	37	37
3	Biomass				
4	SB1122/ BioMAT	3	14	47	47
5	SB32/ReMAT	0	0	28	50
6	Wind				
7	SB32/ReMAT	0	0	9	22
8	Solar PV				
9	SB32/ReMAT	0	2	38	39
10	GTSR/ DAC	0	2	71	71
11	RPS (RFO)	50	50	50	50
12	Renewable Auction Mechanism (RAM)/ PV RAM	0	74	74	74
13	Storage(c)				
14	AB 2514/ IOU Target	0	85	95	95
15	Res. E-4909/ Local Deficiency	0	568	568	568
16	2019 IRP Procurement Track	0	583	744	744
17	46 MMT Scenario Resource Additions	59	1,406	1,758	1,794
18	38 MMT Scenario Additions				
19	Wind	0	0	0	748
20	38 MMT Scenario Resource Additions	59	1,406	1,758	2,542

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(a) Totals may not add due to rounding.

(b) The amounts are the gross amounts. They do not reflect the net amounts after CAM allocation. The net after CAM allocation is shown in Table 4.

(c) Storage quantities do not include any storage procurement conducted as part of the Oakland Clean Energy Initiative (OCEI) as PG&E is not the counterparty for either energy or capacity attributes.

Portfolio additions are expected as a result of the following activities:

a. **Existing Contracts:** Solar PV resources that executed contracts through PG&E's RPS RFOs or RAM program are expected to begin delivering energy for PG&E's bundled customers between 2020 and 2022.[35] In addition, several energy storage contracts from the 2019 IRP Procurement Track, AB 2514 storage target, and local area deficiency (E-4909) are expected to come online by 2022.
b. **RPS Resource Procurement Programs:** PG&E forecasts procurement of additional bioenergy, solar, and wind resources through the Commission's existing mandated procurement programs (e.g., BioMAT, ReMAT, RAM/PV RAM).[36]
c. **Energy Storage Procurement:** PG&E expects to make investments in storage resources that are recoverable through generation rates. For any storage recoverable through CAM, a portion of the capacity will be allocated to other LSEs. PG&E will also be procuring additional storage capacity as part of the mandated IRP Procurement Track issued in 2019. This includes storage capacity for both PG&E Bundled customers as well as LSEs within our service territory that have opted out of procuring this capacity themselves. Table 4 shows PG&E's bundled share of storage capacity. The amounts are net of CAM and distribution resource allocations.

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[35] PG&E's 2021 ERRA Forecast testimony at Chapter 6 provides an overview of PG&E's RPS-eligible contracts. Hyperlink at: https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=613283. PG&E's wholesale electric power procurement website provides information regarding historical RPS RFO and related RPS solicitations: https://www.pge.com/en_US/for-our-business-partners/energy-supply/wholesale-electric-power-procurement/wholesale-electric-power-procurement.page?ctx=business.

[36] These mandated procurement programs are described in Section 4.C of PG&E's Final 2019 Renewable Energy Procurement Plan, filed January 29, 2020 in Rulemaking (R.) 18-07-003. Hyperlink at: https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=593454). While PG&E has currently suspended the ReMAT program as directed by the CPUC in response to a federal court order in *Winding Creek Solar LLC vs. Peevey*, PG&E has modeled additional ReMAT volumes in its portfolio in this IRP under the assumption that future Commission action will address the court's order and revise ReMAT to comply with the Public Utility Regulatory Policies Act (PURPA).

TABLE 4
PG&E STORAGE ADDITIONS NET OF CAM ALLOCATION (MW)

Line No.	Description	2020	2022	2026	2030
1	AB 2514/ IOU Target	0	85	95	95
2	Res. E-4909/ Local Deficiency	0	194	194	194
3	2019 IRP Procurement Track	0	583	716	716
4	Total Bundled Portfolio Storage	0	862	1,005	1,005

(a) Note that the storage additions assumed in Table 4 are attributable to existing procurement requirements (e.g., AB 2514 or Resolution E-4909) as well as the 2019 IRP Procurement Track reliability mandate.

iii. Resource Sales

PG&E's resource portfolio is expected to be reduced as a result of the following forecasted sales:

a. **RPS Sales:** PG&E's planning assumptions include RPS sales quantities as described in its 2020 RPS Plan Filing for 2021–2030. The actual volumes executed may vary from the RPS Plan since the bundled load forecast used in the RPS Plan differs from what is being assumed for the IRP. However, the amount will be equivalent [redacted] in any single year. Based on PG&E's retail sales forecast provided in the CSP Calculator, this is equivalent to approximately [redacted] RPS sales from 2021–2030.[37] This assumption is consistent with D.20-03-028, O.P. 8, and as shown in Table 6 under 'RPS Sales.'
b. **Carbon-Free Energy Sales:** In May 2020, the Commission adopted Resolution E-5046 to give LSEs within PG&E's TAC area the option to receive a pro rata allocation of the GHG-free attributes associated with PG&E's large hydroelectric and nuclear carbon-free resources for the remainder of 2020. The sales levels for years 2021–2030 are consistent with the sales executed for the first year of the carbon-free energy sales PG&E conducted in 2020.[38] This assumption is consistent with D.20-03-028, O.P. 8, and is shown in Table 6 under 'Carbon Free Sales.'

[37] RPS sales assumption is consistent with PG&E's 2020 RPS plan, but total RPS sales volumes differ due to different bundled sales forecasts between PG&E's 2020 LSE IRP and its 2020 RPS Plan.

[38] This is an IRP planning assumption and is subject to change in the future.

iv. Resource Portfolio

The total capacity of generating resources in PG&E's portfolio is expected to decline from 2020 to 2030. Table 5 shows the capacity of resources declining by 6,683 MW from 19,615 MW in 2020 to 12,932 MW by 2030 for the 46 MMT Case. The amounts shown are total resource capacity, not reflecting capacity allocations for CAM or distribution resources. As described in the Study Results section, under the 38 MMT case PG&E adds, for planning purposes, 748 MW of additional wind resources to meet PG&E's 2030 GHG benchmark. This additional procurement considered candidate resources available in the RESOLVE model, including both in-state and OOS wind. Actual future procurement may differ in both resource type and quantity procured and will be based on market conditions at the time of RFO issuance and PG&E's least cost best fit evaluation criteria at that time.

TABLE 5
TOTAL PORTFOLIO RESOURCES BY TECHNOLOGY (MW)

Line No.	Description	2020	2022	2026	2030
1	Solar	4,378	4,381	4,450	4,440
2	Large Hydro[b]	[redacted]			
3	Nuclear	2,240	2,240	0	0
4	Wind	1,780	1,705	1,317	1,167
5	Storage	0	1,396	1,406	1,406
6	Pumped Storage	1,212	1,212	1,212	1,212
7	Small Hydro	525	470	454	421
8	Biomass	267	305	325	217
9	Geothermal	272	22	22	22
10	Biogas	51	48	80	76
11	Natural Gas	[redacted]			
12	Total 46 MMT Scenario	19,615	19,356	13,953	12,932
13	Wind (38 MMT Scenario)	0	0	0	748
14	Total 38 MMT Scenario	19,615	19,356	13,953	13,680

(a) Totals may not add due to rounding.

(b) Capacity reduction of approximately 100 MW after 2020 is due to contract expirations.

(c) These are gross capacity numbers. They do not reflect the amounts after CAM allocation.

The portfolio reductions are driven primarily by decreases in nuclear, geothermal, and natural gas resources. Nuclear capacity decreases to zero by 2026 as a result of the

Commission's 2018 decision approving the retirement of DCPP.[39] The reduction of 4,820 MW in natural gas-fired capacity is due to the expiration of legacy Qualifying Facility (QF) contracts and contracts executed as part of either the QF/CHP Settlement Agreement or the Long-Term Procurement Plan proceeding. Reductions in wind and geothermal capacity are due to the expiration of contracts that were primarily executed through the Commission's RPS procurement programs and that will not be needed for PG&E to meet its RPS compliance requirements.

v. Energy Requirement and Dispatch

For both Conforming Scenarios, the total load requirement and energy generation forecast from resources are shown in Table 6. The energy generation forecast values are the basis of PG&E's bundled generation revenue requirement modeling.

The data includes both forecasted generation from GHG-free resources that are included as part of the CSP calculation[40] as well as generation from dispatchable natural-gas fired and OOS wind resources. The amounts also include planned RPS and carbon-free energy sales described above.

[39] D.18-01-022.

[40] Resources eligible to be used in the CSP calculations are defined in Section 5 of the CPUC's June 15th, 2020 CSP Calculator Documentation document: ftp://ftp.cpuc.ca.gov/energy/modeling/Clean%20System%20Power%20Calculator%20Documentation.pdf.

TABLE 6
CONFORMING SCENARIO ENERGY DEMAND AND SUPPLY (GWH)

Line No.	Description	2020	2022	2026	2030
1	Energy Load				
2	PG&E Bundled Sales	35,945	27,188	27,065	26,777
3	Losses (T&D + Unaccounted for Energy)[(a)]	3,248	2,165	2,155	2,130
4	Total Load Requirement	39,193	29,353	29,220	28,907
5	Energy Supply				
6	CSP GHG-Free Resources				
7	Solar	10,254	10,190	10,518	10,307
8	Large Hydro	[redacted]			
9	Nuclear				
10	Wind	2,934	2,717	2,401	2,060
11	Energy Storage	[redacted]			
12	Small Hydro	1,511	1,419	1,266	1,031
13	Biomass	1,329	1,379	1,669	1,004
14	Geothermal	2,313	141	138	135
15	Biogas	311	374	463	446
16	RPS Sales[(b)]	(9,037)	[redacted]		
17	Carbon Free Sales[(c)]	(4,429)	(10,070)	(5,239)	(5,302)
18	Subtotal CSP GHG-free Resources	32,147	24,420	15,806	17,857
19	Other Resources				
20	Non-UOG Fossil	[redacted]			
21	UOG Fossil				
22	UOG Fuel Cell				
23	Wind (OOS) [(d)]	745	727	0	0
24	Subtotal Other Resources	19,100	11,785	5,657	1,550
25	Total Energy Supply – 46 MMT Scenario	51,247	36,205	21,462	19,407
26	Wind (38 MMT Case Additions)				
27	IRP Procurement	0	0	0	2,089
28	Total Energy Supply – 38 MMT Scenario[(e)]	51,247	36,205	21,462	21,496

(a) 2020 losses are based on PG&E's adopted 2020 ERRA Forecast. Post-2020 losses are based on the CSP tool's 'Baseline Loss Fraction' rate.

(b) RPS sales assumption is strictly a planning assumption and does not represent what PG&E will actually execute. Execution volumes are dependent on a combination of factors (e.g., limits under PG&E's pre-approved RPS sales framework, market demand, market pricing).

(c) This is IRP planning assumption and is subject to change in the future.

(d) CSP tool is only permitted to include Portfolio Content Categories (PCC) 1 RPS generation. These volumes are associated with firming and shaping projects outside of the CAISO.

(e) Actual forecasted fossil dispatch volumes used for the 38 MMT case generation revenue requirement calculations differ slightly from the 46 MMT case due to differences in the energy price assumptions between the two cases.

vi. Renewable Portfolio Standard Compliance Position

PG&E can meet its RPS requirement with physical deliveries from resources that are either currently in its portfolio or that are expected to be added from future procurement already mandated or authorized by the Commission. For both conforming portfolios, PG&E does not need to use banked RECs until [redacted] Figure 1 and Table 7 show PG&E's forecasted RPS compliance position and renewable physical position.[41]

As noted in the Resource Sales section of the Study Results, PG&E's IRP adopts the RPS sales strategy presented in its 2020 RPS Plan of annually [redacted] Currently, PG&E is forecasting sales of approximately [redacted] of incremental bundled RECs from 2021–2030. The actual volumes executed may differ from this forecast as they depend on a combination of factors (e.g., limits under PG&E's pre-approved RPS sales framework, market demand, market pricing, and actual bundled load). However, these volumes should be [redacted]

[41] PG&E's RPS position excludes generation volumes from resources recovered through PG&E's TMNBC cost recovery account per D.18-12-003.

FIGURE 1
CONFORMING SCENARIO RENEWABLE COMPLIANCE POSITION

[redacted]

TABLE 7
CONFORMING SCENARIOS RENEWABLE COMPLIANCE POSITION[a]

Line No.	Description	2020[b]	2022	2026	2030
1	RPS Requirement (GWh)	11,900	10,400	13,200	15,900
2	RPS Requirement (%)	33%	39%	49%	60%
3	RPS Physical Deliveries (GWh)[c]	20,200	17,500	16,800	16,200
4	Planned RPS Sales (GWh)	(9,000)	[redacted]		
5	46 MMT RPS Position (%)	31%			
6	Planned 38 MMT Additions (GWh)	0	0	0	2,100
7	38 MMT RPS Position (%)	31%	[redacted]		

(a) Data rounded to the nearest 100 GWh.

(b) 2020 data is based on PG&E's adopted 2020 ERRA Forecast in D.20-02-047. PG&E will meet its RPS Compliance Period 3 (2017–2020) requirements.

(c) RPS physical deliveries may be different than volumes shown in PG&E's annual RPS plan because of modeling and timing differences.

b. GHG Emissions Results

i. CSP Tool Resource Assumptions

a. **GHG-Free Energy Supply:** Both Conforming Scenarios assume the same carbon-free energy supply with the exception of the additional 748 MW of wind technology in the 38 MMT Conforming Portfolio needed to remain below the GHG emissions benchmark in 2030. This includes all the GHG-free resource types included in Table 6. In both portfolios, PG&E's non-PCC 1 OOS wind resources have been excluded from providing a GHG benefit in the CSP calculator. All additional resources considered to meet the 38 MMT Conforming Portfolio GHG emissions benchmark were candidate resources in the RESOLVE model.

b. **Hydro Imports:** Accurately accounting for the attributes associated with hydroelectric energy imported into California requires a level of centralized verification that does not currently exist. It is possible an LSE can show offtake agreements with a hydroelectric provider. However, without a clearinghouse to track the actual energy from each source there is no way to ensure that the IRP avoids double counting. Therefore, PG&E believes a pro-rata allocation of the hydroelectric energy imported into California is the appropriate way to avoid potential double counting, and PG&E has reflected its pro-rata share in its calculation.

c. **Demand Response:** All customers within PG&E's service area can benefit from PG&E's DR and Demand Response Auction Mechanism (DRAM) programs. Accounting for which customers receive peak load shifting benefits from these programs can be difficult and could result in LSEs showing a load reduction from the same mechanism, leading to potential double counting. PG&E believes a pro-rata allocation of DR capacity is the appropriate way to avoid potential double counting, PG&E has reflected its pro-rata share in its calculation.

d. **Energy Storage (RA-Only):** PG&E has several RA-Only contracts with energy storage assets. Since these contracts have no claim to the energy rights of these resources, they have not been included as part of PG&E's conforming CSP portfolios. For this 2020 IRP and future IRPs, PG&E requests the Commission clarify how LSEs should treat RA only energy storage contracts as part of their CSP portfolios, strictly for IRP GHG emissions modeling. PG&E's exclusion of RA Only storage contracts is meant to prevent potential double counting of these resources as the energy from these assets may be contracted by another entity.

e. **Front-of-the-Meter CHP:** The current CSP tool is set up to calculate each LSE's front-of-the-meter CHP emissions based on their respective load share. This does not account for actual potential individual LSE's CHP retirements and assumes there is no reduction in system CHP capacity over time as California moves towards meeting its SB 100 goals. While the CSP assumption on CHP emissions helps to simplify calculations, it may fail to account for changes individual LSEs are making to reduce CAISO system CHP capacity and consequently GHG emissions.

f. **BTM CHP:** As noted at the end of the Study Methodology section, the CPUC issued an update to the CSP calculator and associated documentation on June 15th, 2020. This update affirmed that BTM CHP emissions were not accounted for in the CSP calculator. To correct for this, the CPUC allocated emissions from these resources using a combination of IOU Service territory CARB emissions allocations and LSE load share. This was prescribed and incorporated into PG&E's emissions results in the form of a more stringent GHG emissions benchmark in the CSP Calculator files.

ii. 46 MMT Portfolio

Based on the 46 MMT CSP tool system emissions factor and PG&E's resource portfolio assumptions described above, PG&E's forecasted 2030 GHG emissions total is 4.543 MMT. This value is below PG&E's 2030 GHG emissions benchmark of 4.737 MMT.

iii. 38 MMT Portfolio

Based on the 38 MMT CSP tool system emissions factor and PG&E resource portfolio assumptions described above, PG&E's initial forecasted 2030 GHG emissions is 4.517 MMT. This value is above PG&E's 2030 GHG emissions benchmark of 3.784 MMT. As described above, PG&E shows an additional 748 MW of wind resources need to be added to its portfolio in order to meet the 2030 GHG emissions benchmark. With the additional wind resources added in 2030, PG&E's 2030 portfolio GHG emissions are 3.784 MMT.

c. Local Air Pollutant Minimization and Disadvantaged Communities

In this section, PG&E describes the local air pollutant emissions from its two Conforming Scenario bundled portfolios based on their respective CSP Tools. PG&E also discusses its efforts to mitigate local air pollutants from its bundled portfolio with early prioritization on DACs. This section also provides insights on customers that reside in DACs and highlights PG&E's programs and regulatory activities that impact DACs.

i. Local Air Pollutants

PG&E's CSP-Tool-calculated portfolio local air pollutant emissions are summarized in Table 8. These emission amounts were determined using the 46 MMT CSP Tool and 38 MMT CSP Tool.

TABLE 8
LOCAL AIR POLLUTANT EMISSIONS (TONS/YEAR)

Line No.	Description	Scenario	2020	2022	2026	2030
1	$PM_{2.5}$	46 MMT Case	587	665	943	682
2		38 MMT Case[(a)]	586	663	943	643
3	SOx	46 MMT Case	271	297	375	270
4		38 MMT Case	271	297	374	267
5	NOx	46 MMT Case	1,772	1,899	2,489	1,772
6		38 MMT Case	1,771	1,897	2,488	1,714

(a) 38 MMT Case Includes additional 748 MW of wind resources procured to meet 2030 GHG requirement.

ii. Focus on Disadvantaged Communities

PG&E supports the Commission's focus on DACs[42] for this IRP filing, especially given the high levels of air pollutants historically recorded in DACs by the California Environmental Protection Agency (CalEPA). PG&E engaged a cross functional working team in order to better collaborate to provide early prioritization and to better address the energy needs of DACs in its service territory. Through this effort, PG&E aims to better align resources, engage stakeholders, and develop a unified approach to better understand the needs of these communities and the unique circumstances they face, and to bring innovative solutions to their critical energy issues. Many of these communities are characterized by high levels of economic hardship. Simultaneously, DACs face a relatively high energy burden compared to other communities in PG&E's service territory. Additionally, the CalEPA identifies these communities as having the highest percentile of adverse scores pertaining to poor environmental health and air quality.

While the issues facing DACs extend far beyond the scope of the CPUC's IRP proceeding, the IRP process is a useful venue to consider how electric sector resource planning and other related decarbonization efforts (such as clean transportation and building electrification) may

[42] Both in the IRP and in D.18-02-018, DACs are defined as follows: "a disadvantaged community shall be defined as any community statewide scoring in the top 25 percent statewide or in one of the 22 census tracts within the top five percent of communities with the highest pollution burden that do not have an overall score, using the most recent version of the California Environmental Protection Agency's CalEnviroScreen tool."

impact air pollution and DACs. The IRP process also presents an opportunity for LSEs to highlight the breadth of activities and programs impacting disadvantaged communities.

Here, PG&E discusses its efforts to mitigate local air pollutants with early prioritization on DACs. We first provide an overview of the DACs in PG&E's service territory. We then provide an overview of PG&E's broad efforts to target its local air pollutant mitigation programs for DACs. Finally, we consider PG&E's bundled portfolio strategy as it relates to mitigation of local air pollutants, with early prioritization on DACs, including PG&E's proactive and forward-thinking work beyond the energy sector to reduce air pollutants across the State with an early prioritization on DACs.

A. Disadvantaged Communities in PG&E's Service Territory[43]

To better identify DACs in PG&E's service territory, PG&E completed an analysis to determine the share of its customers in DACs, considering both residential and business customers within DACs[44] and key demographic information (see Table 9 below). This analysis is provided in comparison to PG&E's overall residential customer base to highlight specific demographics and characteristics that are present in DACs. Of particular note is the high number of DACs that are present in the Central Valley, resulting in a higher proportion of DAC residential and business customers in the Central Valley than elsewhere in the service territory. PG&E identified 548 census tracts within PG&E's electric service territory as DACs.[45]

TABLE 9
OVERALL PG&E AND DISADVANTAGED COMMUNITIES POPULATION IN PG&E ELECTRIC SERVICE TERRITORY

Line No.	Customer Types	Overall PG&E	Disadvantaged Communities	Percent of Overall PG&E
1	Residential Customers	5,445,618	837,154	15%
2	Business Customers	546,087	116,175	21%

Approximately 15 percent of the 5.5 million PG&E electric service territory residential customers live in designated DAC Census Tract Areas. Of these, almost three-quarters (72 percent) are in the Central Valley region, despite the Central Valley region containing only approximately one-fifth of all residential customers in PG&E's electric service territory.

[43] See also Appendix 2: Map of DACs in PG&E's Service Territory.

[44] For the purposes of this filing, customers are defined as distinct PG&E account holders. Customers can have multiple accounts and can also have multiple individuals that are served by their account (e.g. family members or employees).

[45] All accounts reflect PG&E electric service territory customers. PG&E gas only customers are excluded from this dataset.

Residential customers living in a designated DAC Census Tract on average skew younger, more diverse, and more likely to earn an annual household income under $60,000. Spanish as a preferred language is two and a half times as prevalent as in the overall service territory. Residential customers living in DAC Census Tracts are much more likely to work in blue collar/craftsman roles, or as farmers in the Central Valley and Central Coast regions. They are less likely to be retired or to work in professional/technical, administrative, managerial, sales, service, clerical, or white-collar roles than electric service customers living in non-DACs. As with the overall PG&E electric service territory customer base, about a third have children under 18 living at home. Although over half are homeowners, they are much more likely to be renters relative to the overall customer base. Those who are homeowners in DACs are more likely to be living in older, detached dwellings built prior to 1949, except in the Bay Area Region.

TABLE 10

REGIONAL DISTRIBUTION OF RESIDENTIAL CUSTOMER ACCOUNTS IN PG&E ELECTRIC TERRITORY[46]

Line No.	PG&E Region	PG&E Electric Service Territory Customer Accounts (%)	PG&E Electric Service Territory Residential DAC Accounts (%)
1	Bay Area Region	1,186,934 (20%)	109,579 (13%)
2	Central Coast Region	1,626,063 (30%)	56,843 (7%)
3	Central Valley Region	1,205,945 (22%)	599,242 (72%)
4	Northern Region	1,447,219 (26%)	71,609 (9%)

Approximately 21 percent of PG&E's 546,000 business customers are located in DACs. These businesses are predominantly located in the Central Valley region, with approximately two thirds located in this area compared to only one fourth of all business accounts. Based on energy usage, businesses in DACs skew small/medium in size relative to businesses in the broader PG&E electric service territory. Across the entire PG&E electric service territory, businesses in DACs are much more likely than overall businesses to be in wholesale, manufacturing, transportation, construction, retail, and administrative waste industries. They are much less likely to be in public administration, utilities, agriculture, information, mining, management, arts/entertainment, or recreation industries.

[46] This figure is based on the number of residential customer accounts, not the number of residential customers. Some PG&E residential customers may have multiple accounts across PG&E's electric service territory.

TABLE 11

REGIONAL DISTRIBUTION OF BUSINESS ACCOUNTS[47]

Line No.	PG&E Region	PG&E Business Accounts (%)	DAC Business Accounts (%)
1	Bay Area Region	107,545 (20%)	15,273 (13%)
2	Central Coast Region	165,892 (30%)	16,413 (14%)
3	Central Valley Region	141,431 (26%)	77,396 (67%)
4	Northern Region	133,415 (24%)	7,456 (6%)

B. PG&E's Efforts to Mitigate Local Air Pollutants with Early Prioritization on DACs

Consistent with IRP requirements, PG&E used the CSP Tool to estimate the local air pollutant emissions of its bundled portfolio, as reflected in the Local Air Pollutants section of the Study Results. However, using the CSP Tool, PG&E is not able to determine the portion of local air pollutant emissions that directly affect DACs in PG&E's service territory for several reasons. A significant number of customers in certain DACs within PG&E's service territory do not receive electric service from PG&E, and instead receive service from other LSEs, including CCAs and DA providers. Nor are specific resources in PG&E's portfolio tied to a specific set of customers. Moreover, some of the resources in PG&E's portfolio are used to serve customers of other LSEs. Therefore, it is not possible to determine the amount of local air pollutants or starts of natural gas plants *within* DACs in PG&E's service territory that are attributable to PG&E resources serving PG&E bundled customers. Nevertheless, PG&E is focused on minimizing air pollutant emissions from its portfolio for bundled customers with early prioritization of DACs as part of its enterprise goals of providing safe, reliable, affordable energy service while proactively combating climate change. Coupled with our efforts to mitigate local air pollutants, PG&E has a broad array of programs that are designed to improve both the air quality and the economic vitality of DACs and low-income demographics in PG&E's service territory.

PG&E has two guiding principles in developing DAC-targeted programs given the increasing LSE fragmentation in California:

1. All LSEs must support DAC customers. Non-IOU LSEs are offering electric generation service to customers in DACs, and some may even be contracting with or building new facilities in DACs. Furthermore, several programs already exist to support DAC customers, and many non-IOU LSEs can pursue Commission-approved avenues to offer EE and DR programs to their customers, including customers in DACs.

[47] This figure is based on the number of business accounts, not the number of business customers. Some PG&E business customers may have multiple accounts across PG&E's electric service territory.

2. If costs for a program, pilot, or investment are recovered from a service-territory wide customer base, then all service territory customers should be able to participate in or receive benefits from the program, pilot, or investment.

Based on these principles, PG&E actively addresses the challenges of DAC and low-income communities through the following activities:

1. **Considering DACs in PG&E's key efforts related to programs, bill assistance, environmental policy, legislation, and philanthropic efforts.**
2. **Providing leadership across CPUC proceedings and directives aimed at DACs.** A growing number of proceedings include DAC issues. PG&E seeks to provide innovative, cost-effective solutions that support these communities. Proceedings where PG&E is actively considering DACs include:
    - Affordability OIR
    - Building Decarbonization OIR
    - Climate Change Adaptation OIR
    - De-Energization OIR
    - Development of Rates and Infrastructure for Vehicle Electrification OIR
    - Disconnections OIR
    - ESA/California for Alternate Rates (CARE) Income Qualified Programs Application
    - Net Energy Metering OIR
    - Integrated Resource Planning
3. **Increasing awareness, outreach, and accessibility of PG&E program offerings in DACs.** PG&E acknowledges that DACs may have energy challenges that go beyond only low-income program offerings. Even though long-running low-income programs—like CARE and ESA—meet (1) critical bill assistance, (2) EE, and (3) comfort, health, and safety needs; they may be limited in addressing other issues around energy options, environmental resilience, and climate change. PG&E continues to seek creative ways to maximize customer participation in existing programs and maximize customer benefits through program stacking, as is being done in the San Joaquin Valley Electrification pilots.
4. **Seeking new, innovative opportunities to better serve DACs.** A few key examples include the following:
    - **Electrification and fuel switching pilots in the San Joaquin Valley:** Building electrification is an important step in decreasing harmful emissions in California, and the San Joaquin Valley pilots will provide valuable learnings on barriers and challenges to be overcome to electrify low income and DAC customers. The San Joaquin Valley pilots are expected to move into the home assessment and electrification phase in late 2020 and anticipate having lessons learned to share in the 2022 IRP filing.

- **Community solar programs specifically for customers residing in DACs:** Clean energy programs can provide renewable generation to customers residing in DACs, while also providing bill savings. Specifically, the Community Solar Green Tariff enables residential customers in DACs who may be unable to install solar on their roof to benefit from a local solar project and receive a 20 percent bill discount. PG&E launched its first DAC-Green Tariff and Community Solar Green Tariff procurement solicitations in March 2020.

  In addition to community solar programs, PG&E also offers incentives for single-family home solar installations through the Single-family Affordable Solar Homes program, and DAC-SASH (Single-family Affordable Solar Homes) program.
- **Clean Transportation programs designed for DACs:** As discussed in the introduction of this section, the transportation sector is a major contributor of harmful air pollutants in DACs, and transportation electrification can minimize these emissions. The Empower EV program is designed to lower barriers to EV adoption for low income and DAC customers by providing richer incentives and outreach through education.

  PG&E further elaborates on the programs above and describes additional programs, pilots, and investments it currently provides to customers in disadvantaged communities and to low income customers in Table 27 and Table 28 in Appendix 3: PG&E DAC Programs. The tables also indicate whether the program is available to PG&E bundled customers only or if the program is available to all customers in PG&E's service territory.

5. **Increasing partnerships with community-based organizations and local and elected officials to leverage insights, resources, and outreach to DACs.** PG&E has an extensive network of non-profit community-based organizations (CBO) and relationships with local civic leaders to help advance collective policy goals and program offerings. These stakeholders often have unique perspectives and reach into communities that may be harder to penetrate via traditional means. PG&E values these insights and seeks to further activate its local partners for deeper engagement in serving hard-to-reach customers residing in DACs.

As stated throughout PG&E's 2020 IRP, PG&E anticipates a 25 percent decline in bundled electric service in its service territory load by 2030. Nevertheless, PG&E presents a service territory-wide view of its DAC customers and the current and planned activities to support them. PG&E remains committed to serving all DAC customers in its service territory and continues to work collaboratively across numerous organizations to ensure an inclusive and equitable approach for its customers.

PG&E looks forward to participating with stakeholders through the CPUC's IRP process and in other venues to continue to address how to minimize air pollution in DACs and across PG&E's service territory.

C. PG&E's Bundled Portfolio Strategy to Mitigate Local Air Pollutants

PG&E has a long history of emission reduction leadership in California. Between 2011 and 2015, PG&E proactively reduced its bundled portfolio emissions produced by several QFs comprised of approximately 300 MW of coal and petroleum coke facilities. PG&E terminated its contracts with these facilities or, in the case of two of them, successfully converted the resources to biomass. PG&E now has no coal or petroleum coke facilities in its bundled electric portfolio.

More recently, PG&E executed three 50 MW resource adequacy contracts with storage resources in a DAC area to meet its share of the 2019 reliability procurement mandate.[48] PG&E will continue to look for cost-effective opportunities in DAC areas to meet its future mandates and resource needs.

Looking to PG&E's current and forecasted portfolio needs, PG&E does not forecast adding any new natural gas-fired resources to meet its projected energy or system RA needs. Currently, PG&E owns three natural gas fired power plants: Gateway Generating Station, Colusa Generating Station, and Humboldt Bay Generating Station. These plants provide a safe and reliable source of energy, contribute to PG&E's diverse portfolio of generating resources, and provide flexibility to support renewable integration. These plants comply with relevant air pollution regulations and are not located in DACs.[49]

PG&E has seven non-CHP long-term contracts with fossil power plants located in DACs. All but one of these contracts are set to expire by 2024.[50] PG&E does not currently anticipate a need for any future long-term contracts with these facilities to meet its projected bundled-customer energy or RA needs.

PG&E also has ten long-term contracts with fossil CHP resources located in DACs; all but one of these contracts are set to expire by 2022. PG&E does not currently anticipate a need for

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[48] The three 50 MW energy storage projects are being developed by Diablo Energy Storage, LLC, and will be located in Pittsburg, California. See PG&E Advice Letter 5826-E, dated May 18, 2020. PG&E has contracted for an additional 273 MW of energy storage in areas adjacent to DACs.

[49] Note that all of PG&E's owned and contracted units are offered into the CAISO energy market using physical or contractual operating limits. The operations of these plants are controlled by the CAISO, including their starts and stops, cycling, and annual generation outputs. Since PG&E follows least-cost dispatch protocols to bid and operate its resources based on dispatch orders from the CAISO, PG&E has limited control over the resulting dispatch or resulting air pollution emissions from these dispatched resources.

[50] Some of these resources have been awarded RA-only contracts for the 2021–2022 year.

future long-term contracts with soon-to-expire CHP resources. Several of these resources are in local reliability constrained areas.

While PG&E does not intend to retain these resources for its bundled customer portfolio needs, some of these facilities may nevertheless enter the CPE's portfolio if they bid into the CPE's resource solicitations and are the most feasible alternative to meet the CPE's local reliability requirements after accounting for, among other criteria, environmental justice considerations.[51] It is therefore possible that some level of emissions may result from continued, albeit infrequent, operations of some of these resources.

PG&E is committed to collaborate with the CAISO, the CPUC, and other stakeholders (including local LSEs) in finding innovative solutions to cost-effectively meet its reliability needs while reducing emissions. PG&E recently had a successful experience in its OCEI where PG&E worked with EBCE to develop cost-effective solutions to meet a local reliability while reducing emissions in the Oakland area.

Additionally, PG&E is pursuing a range of other air pollutant mitigation strategies to improve air quality in DACs across its service territory, as well as across the state.

Since electricity generation is expected to only account for two to four percent of NOx emissions and one to two percent of $PM_{2.5}$ emissions in California in 2030 while the transportation sector emits 60–75 percent of the state's NOx and 12–22 percent of the $PM_{2.5}$,[52] the key to PG&E's strategy is to help facilitate growth in clean transportation initiatives to more comprehensively address air pollution challenges in the state. PG&E is committed to helping enable the growth of cleaner transportation options for its customers in support of the State's climate and zero-emissions vehicle goals. As reflected in the 2019 IEPR forecast used for both Conforming Scenarios, PG&E estimates over two million light-duty EVs in PG&E's service

[51] CPE is required to use in its LCBF evaluation the "location of the facility (with consideration for environmental justice)." D.20-06-002, O.P. 14.

[52] CPUC Energy Division, IRP Proposed Reference System Plan ("CPUC RSP"), Attachment A, dated September 18, 2017, slides 172–173, available at http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentA.CPUC_IRP_Proposed_Ref_System_Plan_2017_09_18.pdf.

territory by 2030 which would result in an estimated 1,700 MT of avoided NOx and 250 MT of avoided $PM_{2.5}$ emissions.[53]

Beyond light-duty vehicles, PG&E believes that growth of clean fuel medium- and heavy-duty vehicles, which typically use diesel fuel today, can contribute even further to reducing NOx and $PM_{2.5}$ emissions. Clean fuel medium- and heavy-duty vehicles may be powered by electricity, hydrogen, or natural gas. Because multiple technology pathways exist, future levels of each type of clean medium- and heavy-duty vehicles are unknown. PG&E estimates a typical medium-duty EV could avoid an estimated 4,700 grams of NOx and 1,100 grams of $PM_{2.5}$ per year per vehicle, though this depends on the vehicle type and annual miles traveled, which are more varied for these vehicles than light-duty vehicles.[54] For these classes of vehicles, new natural gas engine technologies also provide significant emissions reductions. Equipment manufacturers report that ultra-low NOx engines emit NOx at levels 90 percent lower than the existing federal standard.[55] In addition to operating CNG vehicles within the PG&E fleet, PG&E maintains a network of CNG vehicle refueling facilities that are open to customers and, as of December 2019, are now all supplied with renewable natural gas as part of a 3-year RNG pilot.

PG&E actively supports the adoption of electric vehicles through infrastructure programs, rates, and outreach and education to our customers. While there are many factors that influence a customer's decision to electrify their personal vehicle or commercial fleet, PG&E aims to address specific barriers such as lack of access to charging, total cost of ownership, and lack of awareness of EV benefits through its customer programs. All of PG&E's EV infrastructure programs have a specific focus on increasing access to EV charging in DACs and include richer incentives for and deployment targets in DACs. Through March 2020, 25 percent of the installed and activated ports in PG&E's EV Charge Network program are located in DACs.[56] PG&E also plans on launching the Empower EV program which is the first program of

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[53] Based on a national average 11,556 miles/year traveled (https://www.fhwa.dot.gov/policyinformation/statistics/2018/vm1.cfm), and emissions factors from California Air Resources Board's Low Emission Vehicles III emissions standards (https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/lev-program/low-emission-vehicle-regulations-test), which lead to an estimated avoided emissions of 794 gNOx/vehicle/year and an estimated 113 gPM/vehicle/year.

[54] Based on an estimated annual mileage of 19,058, and emissions factors from CARB's LEVIII emissions standards (https://www.arb.ca.gov/regact/2012/leviiighg2012/levfrorev.pdf).

[55] Source: https://www.gladstein.org/gna_whitepapers/game-changer-next-generation-heavy-duty-natural-gas-engines-fueled-by-renewable-natural-gas/.

[56] PG&E's EVCN Quarterly Report for Q1 2020.

its kind aimed at providing income qualified residential customers with EV chargers and additional incentives to help cover the cost of panel upgrades for eligible customers.

Additionally, through participation in the CARB's Low Carbon Fuel Standard (LCFS) Program, PG&E generates funds to be returned to customers through programs that support EV adoption. Per CARB's regulation, PG&E will spend an increasing percentage of the funds on equity projects beginning with 30 percent in 2022.[57] More information on PG&E's Clean Transportation programs can be found in Table 27 and in the Action Plan section of the IRP. PG&E plans to continue to work with state agencies and other stakeholders to help increase adoption of clean fuel vehicles, particularly in segments that do not yet have viable zero-emissions technologies available and in regions where there is immediate need for air pollution improvements.

d. Cost and Rate Analysis

Table 12 and Table 13 present the revenue requirements and rate analysis for the 46 and 38 MMT scenarios. Both tables are expressed in real 2019 dollars. PG&E's 38 MMT scenario does not incorporate any additional transmission or distribution investments that may be needed to connect new resources and continue reliably serving PG&E's customers. As a result, only the generation revenue requirement varies by scenario.

The rate presentation includes both the SADR containing the rate components recovered from all PG&E customers, and the SABR, which includes the bundled generation rate from PG&E's portfolio plus the SADR to determine the average system rate for bundled customers.

As described in the Study Design section, the Conforming Scenarios relied on the Commission's planning assumptions to develop price assumptions used for bundled energy market purchases and revenues for generation market sales. This includes gas prices, GHG allowance costs, and REC and RA market prices. For the other components of its revenue requirement forecast (transmission, distribution, DSM programs, and other), PG&E created a forecast based upon recent assumptions. PG&E notes that the rate forecasts provided in the IRP are indicative. Actual realized rates will depend upon realized market prices, the outcomes of future rate cases, in particular GRCs, other ongoing proceedings, and market conditions. Future rate forecasts will reflect the information available at that time and may lead to updated revenue requirements associated with additional (or reduced) future costs including, but not limited to, transmission and distribution upgrades, grid modernization costs, clean transportation infrastructure costs, and changes based on PG&E's cost of capital.

The revenue requirement and rate differences between the two scenarios is small. In 2030, the 46 MMT scenario's SABR in 2019 dollars is 20.96 cents per kWh and in the 38 MMT

[57] LCFS regulation (2019) (https://ww3.arb.ca.gov/regact/2019/lcfs2019/fro.pdf)

scenario, the SABR in 2019 dollars is 21.03 cents per kWh. The small rate difference in the generation revenue requirements for the two scenarios is due primarily to different forward market prices, which impacts the dispatch of fossil resources and are used to value sales and purchases. In 2030, the 46 MMT Conforming scenario's bundled generation rate in 2019 dollars is 8.01 cents per kWh and in the 38 MMT Conforming scenario, the bundled generation rate is 8.09 cents per kWh.

PG&E is concerned that the revenue requirements do not fully capture the increase in costs to implement either the 46 MMT or 38 MMT scenarios. For example, based on the technology costs provided by the CPUC additional transmission costs are not required to access the additional renewables such as OOS wind. Moreover, PG&E believes the system will incur additional cost not identified in the IRP to create the flexibility and capacity needed to operate a system with increasing levels of renewables.

TABLE 12
REVENUE REQUIREMENTS AND SYSTEM AVERAGE BUNDLED RATES FOR
46 MMT CONFORMING SCENARIO
(2019 $MILLIONS)

Line No.	Cost Category	2020(1)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Distribution	$ 5,212	$ 6,463	$ 5,951	$ 5,363	$ 5,434	$ 5,466	$ 5,542	$ 5,612	$ 5,701	$ 5,799	$ 5,897
2	Transmission	$ 2,410	$ 2,336	$ 2,153	$ 2,687	$ 2,760	$ 2,838	$ 2,910	$ 2,999	$ 3,091	$ 3,186	$ 3,286
3	Generation	$ 3,506	$ 2,852	$ 2,630	$ 2,497	$ 2,516	$ 2,408	$ 2,282	$ 2,244	$ 2,218	$ 2,200	$ 2,146
4	Demand Side Programs	$ 142	$ 215	$ 248	$ 237	$ 233	$ 228	$ 224	$ 220	$ 215	$ 211	$ 207
5	Other	$ 752	$ 874	$ 690	$ 687	$ 671	$ 658	$ 640	$ 630	$ 524	$ 514	$ 504
6 (sum lines 1-5)	Baseline Revenue Requirement	$ 12,021	$ 12,741	$ 11,672	$ 11,471	$ 11,614	$ 11,599	$ 11,598	$ 11,705	$ 11,750	$ 11,911	$ 12,040
7	System Sales (GWh)	79,440	76,975	76,476	76,259	76,292	76,344	76,392	76,389	76,427	76,407	76,449
8	Bundled Sales (GWh)	35,945	28,904	27,188	27,035	27,035	27,050	27,065	27,057	27,057	26,909	26,777
9	System Average Delivery Rate (¢/kWh)	10.72	12.85	11.82	11.77	11.93	12.04	12.20	12.39	12.47	12.71	12.94
10	Bundled Generation Rate (¢/kWh)	9.75	9.87	9.67	9.23	9.31	8.90	8.43	8.30	8.20	8.18	8.01
11	System Average Bundled Rate (¢/kWh)	20.47	22.71	21.50	21.00	21.23	20.94	20.63	20.68	20.67	20.89	20.96

(a) Revenue requirements and sales for the year 2020 are based on the amounts effective in PG&E's rates on August 1, 2020.

(b) Totals may not add due to rounding.

(c) See Revenue Requirement and Rates Modeling in the Methodology section for SADR and SABR calculation methodology.

TABLE 13
REVENUE REQUIREMENTS AND SYSTEM AVERAGE BUNDLED RATES FOR 38 MMT CONFORMING SCENARIO
(2019 $MILLIONS)

Line No.	Cost Category	2020(1)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Distribution	$ 5,212	$ 6,463	$ 5,951	$ 5,363	$ 5,434	$ 5,466	$ 5,542	$ 5,612	$ 5,701	$ 5,799	$ 5,897
2	Transmission	$ 2,410	$ 2,336	$ 2,153	$ 2,687	$ 2,760	$ 2,838	$ 2,910	$ 2,999	$ 3,091	$ 3,186	$ 3,286
3	Generation	$ 3,506	$ 2,852	$ 2,626	$ 2,499	$ 2,521	$ 2,411	$ 2,272	$ 2,234	$ 2,206	$ 2,179	$ 2,165
4	Demand Side Programs	$ 142	$ 215	$ 248	$ 237	$ 233	$ 228	$ 224	$ 220	$ 215	$ 211	$ 207
5	Other	$ 752	$ 874	$ 690	$ 687	$ 671	$ 658	$ 640	$ 630	$ 524	$ 514	$ 504
6 (sum lines 1-5)	Baseline Revenue Requirement	$ 12,021	$ 12,741	$ 11,667	$ 11,473	$ 11,619	$ 11,602	$ 11,588	$ 11,695	$ 11,738	$ 11,890	$ 12,059
7	System Sales (GWh)	79,440	76,975	76,476	76,259	76,292	76,344	76,392	76,389	76,427	76,407	76,449
8	Bundled Sales (GWh)	35,945	28,904	27,188	27,035	27,035	27,050	27,065	27,057	27,057	26,909	26,777
9	System Average Delivery Rate (¢/kWh)	10.72	12.85	11.82	11.77	11.93	12.04	12.20	12.39	12.47	12.71	12.94
10	Bundled Generation Rate (¢/kWh)	9.75	9.87	9.66	9.24	9.32	8.91	8.40	8.26	8.15	8.10	8.09
11	System Average Bundled Rate (¢/kWh)	20.47	22.71	21.48	21.01	21.25	20.95	20.59	20.64	20.62	20.81	21.03

(a) Revenue requirements and sales for the year 2020 are based on the amounts effective in PG&E's rates on August 1, 2020.
(b) Totals may not add due to rounding.
(c) See Revenue Requirement and Rates Modeling in the Methodology section for SADR and SABR calculation methodology.

e. System Reliability Analysis

Maintaining system reliability is of paramount importance to the IRP process. A robust reliability assessment was a critical component of the long-term procurement plan process and foundational reliability issues should not be overlooked as the Commission analyzes the aggregated LSE Plans. Indeed, without verifying that the PSP meets local, system, and flexible reliability needs, the Commission cannot confirm the PSP will reliably meet its GHG reduction goals.

In the following sections PG&E presents the initial Reliability Analysis results for its 46 and 38 MMT portfolios based on the prescribed method for calculating PG&E's annual system reliability positions. While completing the initial portfolio calculations, PG&E identified two adjustments that need to be made in order to calculate a more accurate estimate of PG&E's system reliability positions. Those adjustments are discussed below as well, with the impacts to PG&E's system reliability positions presented in Table 14.

i. Initial Results

The system reliability calculator from the RDT was used to estimate PG&E's annual system reliability positions for the 46 and 38 MMT portfolios. The initial results for the two scenarios are presented in Table 23 and Table 24 in Appendix 2: System Reliability Calculator Tables. For both cases, PG&E shows that it meets its annual system reliability requirement through 2024 based on the required planning assumptions. While PG&E is showing a system capacity need beginning in 2025, two methodology adjustments are needed to more accurately reflect PG&E's potential need for system capacity during the study period. These adjustments are discussed in the following sections. The adjusted tables are included in Table 25 and Table 26 in Appendix 2: System Reliability Calculator Tables.

A. System Peak Adjustments

Per the 2020 IRP filing requirements, LSE's are to use their respective share of the 2021 RA peak demand allocation to calculate their annual system RA open positions.[58] This is reflected in the position PG&E presents in Table 23 and Table 24. While PG&E supports the use of a standard methodology to assist with a complete allocation of the annual RA requirements across LSEs, PG&E identified two adjustments that need to be made to the RA requirement in order to calculate a more representative estimate of PG&E's September system RA requirements.[59]

First, the use of the draft 2021 system RA allocation requirements appear to result in PG&E being allocated a disproportionate share of the total system RA requirement. PG&E

[58] Only the draft 2021 RA requirements were available for the September 1, 2020 IRP filing date.

[59] System Reliability Analysis Dashboard was published on June 15, 2020. There was not a formal opportunity for stakeholders to provide comments on the Dashboard.

notes the apparent disconnect between the change in bundled energy demand between 2019 and 2021 as measured by the 2019 IEPR Form 1.1c and the change in the bundled RA requirement calculated as the difference between the 2019 Final RA requirement and the 2021 draft RA requirement. Specifically, PG&E's share of the CAISO area IOU, CCA, ESP coincident demand only decreases by [redacted] percent from [redacted] percent to [redacted] percent while PG&E's bundled sales decline 15.6 percent from 2019 to 2021.[60] While changes in energy and peak demand do not necessarily move in perfect tandem, they are none-the-less closely correlated. The fact that the change in the peak requirement does not more closely mirror the change in energy demand forecast is problematic and likely related to the ongoing shift of PG&E's bundled customers to both CCA and DA since 2015. As a result, rather than using the draft 2021 RA requirement, PG&E proposes to anchor the derivation of the bundled RA requirement to its 2019 share of system RA calculated using PG&E's final 2019 RA requirement.[61]

The second adjustment addresses the fact that, as currently specified, the RDT assumes the bundled portfolio's share of the system peak is constant over the entire forecast horizon despite the declining PG&E bundled sales forecast from 2019 to 2030 shown in IEPR Form 1.1c. Specifically, the required annual energy demand forecast assumptions show PG&E's bundled customer energy demand declining 22 percent from 34,262 GWh in 2019 to 26,777 GWh in 2030. Over that same period of time, the CAISO sales forecast only decreases 1 percent, indicating that the PG&E energy drop is reflective of the reduction in PG&E's share of the system load. Therefore, it is appropriate to assume that PG&E's share of the CAISO system RA requirement declines in-line with its declining bundled customer energy demand forecast.[62] To that end, PG&E proposes for each year of the forecast to scale the initial 2019 bundled share of system RA by the ratio of forecasted energy demand divided by the level of demand in 2019. However, PG&E recognizes that simply scaling by load might lead to too great a reduction in the bundled peak requirement as some of the reduction in load is driven by factors that impact the whole CAISO system. To account for this, PG&E has adjusted the load scaling factors by subtracting in each year an amount equal to the percent change (relative to 2019) in the CAISO area IOU, CCA, ESP non-coincident demand forecast specified in the "estimate_System_RA_Requirement" tab of the RDT.[63]

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[60] PG&E's bundled sales data based on CSP Tool IEPR Form 1.1c.

[61] PG&E's 2019 bundled sales in IEPR Form 1.1c align most closely with PG&E's adopted 2019 bundled sales forecast in D.19-02-023.

[62] PG&E's RA requirement adjustment accounts for both its change in annual energy demand and the annual capacity demand change for CAISO area IOU, CCA, and ESP load.

[63] PG&E's proposed adjustment expressed in algebraic terms is:

After incorporating both of these adjustments, PG&E's annual September system peak RA requirement, including the planning reserve margin (PRM), is reduced by approximately [redacted] in 2022, 2026, and 2030, respectively. Furthermore, in order for the Commission to review other LSEs' respective annual system reliability positions, similar adjustments need to be made for calculating their annual system RA requirements.

B. Adjusted Hydroelectric Resource Effective Load Carrying Capacity Assumptions

Overall, PG&E agrees with and supports the RDT adjusting the NQC values for hydroelectric resources downwards from their maximum capacities when calculating the system RA supply position for an LSE's portfolio.[64] However, based on PG&E's review of the effective load carrying capacity (ELCC) assumptions used in the RDT to adjust the NQC values for hydroelectric resources, PG&E believes the ELCC assumptions being used for hydroelectric resources understate the amount of system RA that should be counted from them. Furthermore, the hydroelectric ELCC adjustments used in the RDT are not consistent with those used in RESOLVE for the RSP.

While a majority of hydroelectric resources are considered dispatchable by the CAISO,[65] the RDT applies the non-dispatchable hydroelectric ELCC factors from the CAISO's 2020 net qualifying capacity (NQC) list to all hydroelectric resources.[66] The non-dispatchable ELCC adjustment factors vary by month, from 26 to 44 percent. Application of the non-dispatchable factors to dispatchable units results in an undercounting of system RA from PG&E's hydroelectric resources, in particular during the peak demand months of July through September when an average non-dispatchable adjustment of 28 percent is being applied.[67]

For this 2020 IRP filing, PG&E supports using the 15 percent planning adjustment factor from RESOLVE for hydroelectric resources in the RDT. This factor better represents the

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$$BRA_t = CAISOC_t \times \frac{BRA_{2019}}{CAISOC_{2019}} \times \left\{1 + \left(\left(\frac{(BLOAD_t - BLOAD_{2019})}{BlOAD_{2019}}\right) - \left(\frac{(CAISONC_t - CAISONC_{2019})}{CAISONC_{2019}}\right)\right)\right\}$$

Where:

$BRA_t = Bundled\ RA\ requirement\ in\ Year\ t$

$CAISOC_t = CAISO\ area\ IOU, CCA, ESP\ coincident\ demand\ in\ Year\ t$

$BLOAD_t = Bundled\ energy\ demand\ in\ Year\ t$

$CAISONC_t = CAISO\ area\ IOU, CCA, ESP\ non - coincident\ demand\ in\ Year\ t$

[64] In the past, for some planning purposes, the NQCs for hydroelectric resources were assumed to be the resources' PMax capacity.

[65] See page 32, 2019–2020 IRP Inputs & Assumptions.

[66] See '2020 Technology Factors' tab in CAISO's 2020 Net Qualifying Capacity List excel workbook.

[67] Average July through September hydro ELCC adjustment from the 'ELCC' tab in the RDT.

expected NQC that hydroelectric resources will provide during peak demand months. It also aligns the calculation methodologies being used between RESOLVE and the RDT, improving consistency within the IRP.

For future IRP cycles, PG&E proposes the Commission use the dispatchable hydroelectric calculation methodology recently adopted by the Commission in D.20-06-031. While not available for this 2020 IRP cycle, D.20-06-031 approves the use of a methodology for calculating monthly dispatchable hydroelectric NQC values that better accounts for hydrological variability and other operational constraints.

For PG&E's 2020 IRP system RA position, updating the monthly hydroelectric ELCC values to a fifteen percent adjustment results in an annual increase in the NQC values for PG&E's hydroelectric resources of approximately [redacted] over the planning horizon.

ii. Final Results

Making the adjustments to PG&E's bundled system RA requirement and hydroelectric NQC values discussed above materially impacts PG&E's annual bundled system RA positions. The total bundled supply, system RA requirement and shortfall/surplus amounts for both the initial and adjusted results are shown in Table 14.

TABLE 14
46 MMT INITIAL AND ADJUSTED RA POSITION COMPARISON

Initial	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
TOTAL supply, NQC MW	[redacted]									
Load (MW)										
Load +15% PRM (MW)										
Supply minus load: Shortfall (-) or Surplus (+), in MW										
Adjusted										
TOTAL supply, NQC MW										
Load (MW)										
Load +15% PRM (MW)										
Supply minus load: Shortfall (-) or Surplus (+), in MW										

(a) Totals may not add due to rounding.

The adjusted reliability results shown in Table 14 indicate a small unfilled September system capacity requirement for PG&E's bundled load of approximately [redacted] starting in 2025 that increases to approximately [redacted] by 2030. PG&E expects a majority of this open position will be filled with system RA allocated by the CPE as a result of local RA purchases. Any potential remaining short positions would then be met with capacity market transactions as needed.

The positions calculated here are likely to change based on impacts from the CPE, potential additional load departures and future Commission decisions.[68]

f. Hydro Generation Risk Management

As presented in Table 6 and Table 25, PG&E's bundled customers rely on a variety of generation technology types for providing carbon-free energy and system capacity. While the proportional contribution differs between energy and capacity, hydroelectric resources play a critical role in PG&E meeting both its reliability and GHG emission planning requirements.

The following sections provide additional detail regarding PG&E's hydroelectric resources and their expected energy and system reliability supply as well as associated risks for each.

i. Energy

A. Hydro Generation for 2020 IRP

Consistent with PG&E's 2018 IRP and past IEPR forecast filings, PG&E based its 2020 IRP hydroelectric generation assumption on its most recent long-term average performance analysis of its hydroelectric resource portfolio.[69] PG&E currently uses a thirty-year performance average in its hydroelectric generation forecast to mitigate year-to-year variability, including the impacts of in-state drought. A thirty-year average balances the requirements for a sufficiently long period of record to capture hydrological variability (e.g., cycle of droughts and wet years) and a sufficiently short period of record to reflect current operating conditions. Operating condition drivers include new FERC license constraints, unit characteristics, watershed characteristics, climate change, and market value. The thirty-year performance average is used in the forecasts of energy production, GHG emissions and expected costs.

Based on this approach, PG&E's annual hydroelectric generation forecast in the 2020 IRP is approximately 10 percent lower using the most recent long-term average analysis compared to the prior analysis covering 1981–2010. This decline reflects the impact that the

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[68] PG&E's plan does not reflect possible reliability requirement changes that the Commission may order in response to the August 2020 rolling blackout events.

[69] PG&E's most recent long-term hydro averages are based on 1987 through 2016 historical data.

drought period from 2012–2016 had on PG&E's thirty-year average hydroelectric generation as well as new FERC license operating conditions and other drivers listed above.

B. Modeling Considerations for Future IRP Cycles

In addition to relying on recent long-term average performance, PG&E is considering incorporating additional explicit modeling methodologies for use in future IRP cycles. These additions would capture known future operating condition drivers, such as upcoming FERC license conditions and planned maintenance outages, to better estimate future hydroelectric generation.

C. Comparison to Reference System Portfolio

As described in the Hydro Generation Risk Management section above, PG&E currently estimates its hydroelectric generation based on its most recent thirty-year average hydroelectric generation analysis. For the large utility-owned hydroelectric resources, this equates to a capacity factor assumption of approximately 43 percent.[70] By comparison, the capacity factor for the prior thirty-year average hydroelectric generation was 48 percent.

As described in the 2019–2020 IRP Inputs and Assumptions document, both the 46 and 38 MMT scenarios derived the annual hydroelectric generation assumption as part of the representative sampling of days method used by RESOLVE.[71] The daily hydro conditions sampled were specifically based on the 2008, 2009, and 2011 hydro years. Based on the published RSP results, this methodology resulted in a capacity factor assumption of approximately 30 percent for large hydroelectric resources within the CAISO.[72]

Compared to PG&E's recent thirty-year average, the RSP assumes approximately 30 percent less generation from large hydroelectric resources located within the CAISO.[73] This equates to approximately 7,800 GWh less in annual generation from CAISO large hydroelectric resources. Given that PG&E's large hydroelectric capacity represents a third of the CAISO's large hydroelectric capacity, PG&E recommends that the CPUC review and update as appropriate the expected generation from large hydroelectric resources interconnected to the CAISO. While PG&E has limited historical CAISO-level data, PG&E's preliminary analysis of large hydroelectric generation from 2013–2019 shows generation levels approximately 10 percent greater than what is currently being assumed in RESOLVE. Since much of this record is

[70] Capacity factors represent the ratio of expected output compared to the maximum output for a unit generating at its maximum capacity for every hour in a year.

[71] Inputs & Assumptions: 2019-2020 Integrated Resource Planning, p.68.

[72] Derived from the reference system plan results of 18,668 GWh large hydroelectric generation from 7,070 MW.

[73] Calculated based on PG&E's 30-year capacity factor of 43 percent compared to RESOLVE's 30 percent for large hydroelectric resources.

comprised of the 2012–2016 drought period, PG&E expects that average generation from a thirty-year period would be closer to PG&E's capacity factor assumption of approximately 43 percent. This is based on PG&E's analysis of its utility-owned hydroelectric resources during the 2013–2019 period compared to its recent thirty-year average analysis.

ii. System Reliability

A. Planning Assumptions for Hydro Reliability Supply

As described in the Final Results subsection of the System Reliability Analysis section, for calculating each LSE's system RA open positions in the 2020 IRP filing PG&E proposes using the Commission's fifteen percent large hydroelectric resource ELCC adjustment factor from RESOLVE in the RDT as well. Additionally, for future planning cycles, the Commission should adopt the methodology from D.20-06-031 for calculating monthly dispatchable hydroelectric NQC values. This methodology will account for hydrological variability and other operational constraints resulting in more representative reliability planning assumptions for hydroelectric resources.

iii. Risks and Planning

A. GHG Emissions

As described above PG&E currently uses a thirty-year performance average in its hydroelectric generation forecast to mitigate year-to-year variability, including the impacts of in-state drought. The thirty-year average is used in the forecasts of GHG emissions, as well as, energy production and expected costs. PG&E periodically updates the thirty-year average using the most recent data. Furthermore, as described in the Modeling Considerations for Future IRP Cycles subsection of the Study Results section, PG&E expects to refine its long-term hydroelectric generation modeling methodology for use in future IRPs, which would further improve the assessment of risk that in-state drought poses to PG&E's GHG emissions planning.

Compared to PG&E's 2018 IRP, PG&E's bundled customers no longer bear the full risk associated with potentially lower levels of hydroelectric generation. This is due to the recontracting of carbon-free energy sales that PG&E expects to occur, which reduces PG&E's bundled customer's reliance on generation from large, utility-owned hydroelectric resources for GHG emissions planning. Further details on this assumption are provided in Conforming 46 MMT Scenario and 38 MMT Scenario Portfolios subsection of the Study Results section.

B. Reliability Supply

Unlike GHG emissions where fluctuations in annual hydroelectric generation volumes have a direct impact on an LSE's total GHG emissions, in-state drought conditions pose a more limited risk to reliability planning since most of PG&E's hydroelectric resources are flexible and have operational discretion on when and how much to dispatch. Even during drought conditions, the supply of water can be reoptimized and released when and where it is most needed to provide peak hour availability and generate at their respective NQCs. However, that flexibility can be reduced during sustained extreme drought, whereby releases could become constrained by late summer or early winter prior to the onset of precipitation for the next water year.

C. Expected Costs

As with the energy and GHG emission forecasts discussed above, PG&E uses a recent thirty-year performance average to forecast energy from hydroelectric generation to mitigate year-to-year variability. The cost risk associated with lower-than-forecasted energy production from the hydroelectric resources is not solely borne by PG&E's bundled customers because utility-owned hydroelectric resources are recovered through the PCIA rate. Since a majority of customers in PG&E's service territory are subject to PCIA charges, PG&E's bundled customers are responsible for less than half of the above market cost from utility-owned hydroelectric resources.[74]

While the expected annual cost impact from in-state drought is relatively flat for long-term position planning, the primary risk posed by in-state drought is associated with the short-term, year-to-year fluctuations in actual hydroelectric generation. Given that the costs for PG&E's hydroelectric resources are predominantly fixed, annual fluctuations in hydroelectric generation resulting from actual hydro conditions impacts the CAISO energy market revenues for hydroelectric resources. The next section provides further detail regarding how PG&E's hedging strategy addresses this short-term hydro condition risk.

D. Hedging and Contingency Planning

PG&E's current hedging strategy addresses near term market price risk exposure for PG&E's bundled customers. As the expected hydroelectric generation is updated based on more recent hydro condition data, PG&E updates its hedge position accordingly to reflect either more or less expected generation due to a wetter or drier hydro year, respectively.

Beyond hedging short term market price risk, PG&E has developed a risk mitigation plan regarding potential large uncontrolled water releases.[75] In its plan PG&E identifies potential risks for large uncontrolled water releases and proposed mitigation actions to address those risks. In addition to addressing safety concerns, the mitigation plan also reduces the potential for lost water supply and, therefore, an associated increase in future GHG emissions due to a reduction in hydroelectric generation.

[74] Based on prescribed PG&E bundled customer sales assumption for the 2019-2020 IRP cycle.

[75] A.20-06-012, Chapter 13 Risk Assessment and Mitigation Phase Risk Mitigation Plan: Large Uncontrolled Water Release.

g. Long-Duration Storage Development

Currently, PG&E is not actively pursuing development of pumped storage resources but recognizes the potential value that additional pumped storage or other long-duration storage technologies could provide as California integrates increasing levels of intermittent renewable energy resources and decarbonizes its economy.

PG&E is an active member in a variety of energy storage organizations and stakeholder working groups, providing an opportunity to actively monitor and work with industry members to track new developments on the technology side and policies that support deployment of long-duration storage in an equitable way for bundled and unbundled customers.

As we consider long-duration solutions within an optimized portfolio of resources that can meet key IRP objectives, current market and regulatory challenges will need to be addressed, including the following:

- Regulatory clarity on the specific needs that long-duration storage can cost effectively address
- Determination of value of additional duration beyond four-hour needs, in light of the current RA market and procurement models
- Consideration of how procurement of large, capital-intensive resources will be accomplished among a large and diverse set of LSEs (e.g., through an expanded use of a CPE)
- Policy support in legislative and regulatory arenas for cost-recovery mechanisms that ensure that all benefiting customers pay
- Consideration of State funding for pilot and demonstration projects that can help to drive down technology costs

h. Out-of-State Wind Development

Currently, PG&E is not actively pursuing OOS wind resources. However, PG&E is actively monitoring developments in this market segment and will continue to do so, in part, because OOS wind was selected as the incremental resource addition in PG&E's 38 MMT scenario. Key issues of interest include delivery of OOS resources into the CAISO, the rules associated with the counting of these resources toward meeting RPS targets and the possibility of additional transmission investments not identified in this IRP.

i. Transmission Development

PG&E has included resource location information for new contracted resources in the RDT as required by the Commission. For more information, see the RDT, Unique Contracts tab, for a list of resources and their queue position.

For its 38 MMT Conforming scenario, PG&E made generic resource additions to meet its 2030 GHG emission benchmark. These resources do not yet have an interconnection queue position. To ensure that the generic resources are a part of the CPUC Reference System Portfolio, PG&E limited the candidate resources available to meet PG&E's open GHG position to those chosen at the system level by the RESOLVE model. Therefore, PG&E's transmission assumptions are consistent with the CPUC Reference System Plan assumptions.

As noted in the Lessons Learned section, the actual transmission need and cost will be available after CAISO's reliability assessment in its Transmission Planning Process (TPP). Given the level of increase in renewable resources, it is likely that additional transmission investment will be required to interconnect and reliably integrate the new renewables and storage resources to the CAISO system.

IV. Action Plan

Based on the study objectives and results of PG&E's IRP analysis, this section presents PG&E's Action Plan to source the resources identified in its Conforming Portfolios.

The Action Plan presented below is the same for both Conforming Scenarios. Nearly all of PG&E's near-to-mid-term procurement activities are driven by existing state policy mandates and implementation of DSM programs. Due to past and expected load loss to CCAs and the composition of PG&E's existing resource portfolio, PG&E has sufficient resources in the near-to-mid-term to meet RPS and system RA compliance.

For GHG compliance, no incremental resources or action is needed to meet the 2030 46 MMT benchmark. To meet the 2030 38 MMT benchmark, PG&E has identified a need to procure an additional 748 MW of in-state and OOS wind on existing transmission capacity.

The Action Plan does not identify actions for procurement of the incremental wind resources. Should the Commission adopt a 38 MMT target for electric sector and/or there are significant changes in PG&E's portfolio resulting from the PCIA WG3 decision, PG&E will develop a procurement plan to meet its portfolio needs in a LCBF manner and may seek authorization from the Commission for execution of additional GHG-free resource procurement prior to filing its next IRP. PG&E will seek a technology-neutral procurement process to select the LCBF resources to fulfill PG&E's compliance requirements. Given that portfolio and market conditions will differ between the planning and procurement stages, PG&E may procure different resource-types and volumes than that shown in the IRP.

While this Action Plan focuses on describing PG&E's GHG-free resource additions, PG&E also engages in market sales of energy products to benefit its bundled customers in compliance with its Commission-approved BPP and other relevant resource plans (e.g., RPS Procurement Plan).

In implementing its IRP Action Plan, PG&E is committed to serving customers in disadvantaged communities. Regarding outreach to disadvantaged communities, PG&E describes its existing outreach activities in Study Results and in Appendix 4: Map of DAC Areas in PG&E's Service Territory. Given evolving market dynamics, PG&E's current energy procurement and customer engagement activities are driven primarily by state policy mandates and the implementation of DSM programs, many of which already include targeted offerings to DAC communities.

The remainder of this section is organized by resource types to cover PG&E's current procurement activities, identification of key barriers, and recommendations for Commission directives or action to cover the Narrative Template requirement sections IV a through IV d.

a. PG&E Procurement Activities

PG&E regularly evaluates its resource portfolio to provide safe, reliable, affordable energy to its bundled customers. In this exposition of our ongoing procurement activity, we have sought to demonstrate the breadth of PG&E's procurement programs generally and with respect to our IRP scenario results.

PG&E commonly has a wide range of procurement solicitations underway. A snapshot of current procurement solicitations is provided in Appendix 5: PG&E's Current Procurement Activity. Information about online dates for PG&E's planned procurement, as relied upon in preparing this IRP analysis, is included in the RDT that accompanies PG&E's IRP LSE Plan. PG&E recommends that the Commission refer to the updated list of its procurement solicitations on its website for the most up-to-date information.[76]

Following the description of PG&E's wide-ranging procurement activities, this report then discusses proposed activities particularly associated with PG&E's IRP scenario analysis.

i. Renewable Energy

PG&E will continue to meet its RPS requirements as established by the California Legislature. In both Conforming Scenarios, PG&E is well-positioned to meet its RPS requirements and does not have any incremental need for RPS resources until after 2030. To address PG&E's long position, PG&E has not signed new RPS contracts (outside of mandated procurement programs) since the 2012 RPS procurement solicitation and continues to assess potential sales of excess RPS volumes. Moreover, in CPUC proceedings where new procurement mandates are proposed, PG&E is an active stakeholder and continues to reiterate its lack of RPS need.

PG&E's strategy for procurement and sales of RPS energy is approved by the CPUC as part of PG&E's Annual RPS Procurement Plan filing. Any changes to PG&E's RPS procurement strategy will be detailed in PG&E's future RPS Procurement Plans.

[76] https://www.pge.com/en_US/for-our-business-partners/energy-supply/wholesale-electric-power-procurement/wholesale-electric-power-procurement.page.

TABLE 15
RENEWABLE ENERGY – SUMMARY OF PG&E STUDY RESULTS, ACTIONS, AND RECOMMENDATIONS

Existing Near-Term Actions[(a)]	• Administer BioMAT program auctions. • Suspend ReMAT program activity, pending resolution of legal challenge.[(b)] • Bioenergy Renewable Action Mechanism (BioRAM) procurement • DAC solicitations twice a year. • GTSR solicitations once a year. • PURPA/Renewable CHP procurement. • Continue sales of RPS energy.
Key Barriers	• Load forecast uncertainty, including future CCA departure. • Uncertainty regarding the PCIA OIR outcome.
Proposed New Near-Term Actions/ Commission Direction	Commission decision on PCIA WG3.
Recommendation for Future IRPs	Continue modeling RPS resources as candidate resources.

(a) Resource additions are from either existing contracts not yet online or future procurement for mandated procurement programs. This total RPS generation value includes an assumption of continued RPS bundled energy sales.

(b) PG&E has currently suspended the ReMAT program as directed by the CPUC in response to a federal court order in *Winding Creek Solar LLC v. Peevey*. On June 26, 2020 the CPUC issued a staff proposal with proposed modifications to bring ReMAT into compliance and subsequently reopen the program. PG&E has modeled additional ReMAT volumes in its portfolio in this IRP under the assumption that future Commission action will address the court's order and render ReMAT compliant with PURPA.

Existing Near-Term Actions

PG&E is currently taking the following steps related to RPS procurement:

Administer BioMAT Program Auctions: PG&E will continue to administer its bi-monthly BioMAT auctions for waste management and dairy/agricultural projects, and monthly BioMAT auctions for sustainable forest management projects. On October 3, 2018, the CPUC issued a staff proposal, initiating a BioMAT program review. On March 10, 2020 the CPUC issued a revised staff proposal for the program review. PG&E has participated in comments, reply comments, and a workshop. On July 24, 2020 the CPUC issued a proposed decision extending the program end date to December 31, 2025 and implementing various other program changes. Next steps will include market participants submitting comments to the proposed decision by August 13, 2020 and CPUC issuing a final decision. Through BioMAT, PG&E is required to procure a total 111 MW of bioenergy resources. Currently PG&E has procured 31 MW under this program.

Suspend ReMAT Program Activity, Pending Resolution of Legal Challenge: On December 6, 2017, the U.S. District Court in *Winding Creek Solar LLC v. Peevey* held that the ReMAT program violates PURPA. In response to the District Court decision, the CPUC ordered the IOUs to suspend all program activity, pending further Commission action. On June 26, 2020 the CPUC issued a staff proposal with proposed modifications to bring ReMAT into compliance and subsequently reopen the program. PG&E has participated in comments and reply comments. Next steps may include a revised staff proposal or Proposed Decision.

BioRAM Procurement: PG&E will continue to comply with SB 901 and CPUC Resolution E-4977 which requires PG&E to seek to extend various Biomass contracts by five years and modify feedstock requirements. PG&E has so far received CPUC approval for one amendment to an existing BioRAM contract and one new 5-year BioRAM contract. PG&E will offer the RA and RECs generated by BioRAM facilities for sale in accordance with the Tree Mortality Non-bypassable Charge decision.

DAC Solicitations: In compliance with E-4999, PG&E will hold two solicitations per year seeking new solar PV projects for Disadvantaged Communities Green Tariff ("DAC-GT") and Community Solar Green Tariff ("CS-GT") until the remaining capacity is procured. PG&E's allocation is 54.82 MW for DAC-GT and 14.20 MW for CS-GT. PG&E completed its first solicitation for DAC-GT and CS-GT and is working toward execution with counterparties.

GTSR Solicitations: In compliance with E-5028, PG&E will hold a minimum of 1 solicitation per 12-month period for as-available peaking, as-available non-peaking, and baseload projects until the remaining capacity is procured. PG&E is required to procure 272 MW under Green Tariff Shared Renewables ("GTSR"). GTSR has two program components, and PG&E has procured about 53 MW under Green Tariff (brand name Solar Choice) and about 1.66 MW under Enhanced Community Renewables (brand name Regional Renewable Choice).

PURPA/Renewable CHP: In compliance with the 2010 Qualifying Facility and Combined Heat and Power (QF/CHP) Settlement Agreement, the Standard Offer PURPA contract remains available to renewable Qualifying Facilities.

Continue Sales of Bundled RPS Volumes: Pursuant to the Commission's approval of PG&E's 2020 RPS Procurement Plan, PG&E continues to consider opportunities for sales of RPS volumes that benefit its bundled customers. Execution volumes are dependent on a combination of factors, including limits under PG&E's pre-approved RPS sales framework, market demand and market pricing.

Key Barriers to Renewable Energy

PG&E notes two key uncertainties impacting its RPS strategy:

(1) Load Forecast Uncertainty, Including Future CCA Departure: PG&E's RPS need is a function of its forecasted bundled service retail sales. The energy landscape in California has changed significantly over the last few years and an emphasis on customer choice, in the form of DG, CCAs and potential further reopening of DA, has dramatically changed PG&E's expectation of future retail sales. Uncertainty regarding future levels of load departure to other suppliers, as well as load growth from EV adoption, creates uncertainty with respect to PG&E's future RPS need. Based on PG&E's current view of its bundled service load, PG&E has no incremental RPS procurement need in the Conforming Scenarios until after 2030.

(2) Regulatory Uncertainty: PG&E's RPS strategy is highly dependent upon the CPUC's resolution of Phase 2 of the PCIA proceeding, for example depending on whether the CPUC adopts a proposal to voluntarily allocate PG&E's PCIA-eligible RPS portfolio in the PCIA proceeding.

Recommendations for Commission Action and in Future IRPs

Renewable energy should continue being modeled as a candidate resource to meet the system's RPS and GHG reduction needs. Future IRP cycles should compare utility-scale renewable resources against demand-side alternatives, utilizing consistent valuations for both the supply-side and demand-side resources. Additionally, the costs assumed for renewable energy should reflect current market prices as closely as possible and a broad range of future costs should be considered.

ii. Energy Storage

PG&E is actively implementing California's programs to develop cost effective energy storage resources in the state to integrate renewable resources, provide output in periods of peak demand, and reduce GHG emissions. Additionally, in some cases energy storage projects can be a preferred alternative to provide grid efficiency and reliability in lieu of conventional wires solutions. Energy storage technology can also provide enhanced grid resiliency for critical customers during grid disturbances. PG&E's energy storage strategy includes all of these use cases and seeks to ensure the proper regulatory rules are in place to enable them.

PG&E is accelerating deployment of energy storage on its grid through owning and operating storage resources, procuring storage through third party contracts, testing innovative storage solutions through pilot projects, and enabling customer adoption of energy storage. PG&E envisions a large and growing need for energy storage in the future as California continues to increase renewable energy production and pursue GHG reduction goals. There is a suite of innovative storage technologies, including power to gas, pumped hydro, and vehicle to grid technologies, that PG&E feels should be considered "eligible storage technologies" to meet the state's needs. In summary, there is ample opportunity going forward for utilities, third-party storage providers, and retail customers to be part of the energy storage solution that incorporates a wide array of storage technologies.

TABLE 16
ENERGY STORAGE – SUMMARY OF PG&E STUDY RESULTS, ACTIONS, AND RECOMMENDATIONS

Existing Near-Term Actions[(a)]	• AB 2514 Energy Storage RFOs • AB 2868 Distributed Energy Storage Investments and Programs • OCEI • System Reliability RFOs
Key Barriers	• Cost effectiveness of storage vs. traditional grid solutions • Uncertainty for Energy Storage Devices Providing Services Across Grid Domains • Lack of enhanced visibility, monitoring and control systems for utility operations to ensure grid needs are addressed and fully realize the value of energy storage • Maintaining distribution grid reliability in multi-use applications (MUA) • Unresolved rules and requirements in regulatory proceedings that can both optimize the use of storage technologies and ensure grid services are provided.
Proposed New Near-Term Actions/ Commission Direction	None at this time.
Deviations From Current Resource Plans	PG&E's 2020 Energy Storage Procurement and Investments Plan covered only required procurement under AB 2514. All storage procurement outside of or beyond those targets (such as the System Reliability RFOs) was not included in that Application.
Recommendation for Future IRPs	Continue modeling energy storage resources as candidate resources.

(a) PG&E's 2020 IRP only includes energy storage needed to meet: (1) existing procurement requirements (e.g., AB 2514); or (2) other procurement proposals already made by PG&E (e.g., System Reliability RFOs). PG&E did not include assumptions about the procurement of energy storage for any other purposes, including to address future reliability or grid needs or to meet regulatory, CAISO or legislative requirements.

Existing Near-Term Actions

AB 2514 Energy Storage RFOs: PG&E is on track to comply with the state-wide energy storage adoption requirements of 580 MW by 2024 (AB 2514). PG&E has conducted two energy storage solicitations to date.

AB 2868 Distributed Energy Storage Investments and Programs: In March 2018, PG&E filed its proposal with the CPUC to deploy distributed energy storage in compliance with AB 2868.[77] PG&E included in its proposal up to 5 MW BTM thermal energy storage program which provides incentives for low-income customers and customers in DACs to electrify their water heating and shift the associated load to off-peak hours. PG&E is waiting for CPUC action on its Advice Letter implementing the program. Once approved, the program is expected to launch in 2020 and enroll 9,400 customers, who will benefit from energy bill savings and reduced onsite emissions from propane-based water heating.

Oakland Clean Energy Initiative: PG&E and the CAISO have worked collaboratively over the last several transmission planning cycles to study the reliability needs in the Oakland area, leading to the development of the OCEI. This project will leverage clean energy resources in the Oakland sub-area to support grid reliability as a less costly alternative to building a new transmission line. OCEI was approved by CAISO in March 2018, and a competitive solicitation was launched in May 2018. In April 2020, PG&E executed two Local Area Reliability Service (LARS) Agreements for a total of 43.25 MW of energy storage ("OCEI Preferred Portfolio") and filed an Application with the CPUC for cost recovery approval. The OCEI Preferred Portfolio, along with traditional transmission upgrades and load switching, will meet the CAISO reliability need and allow an aging fossil generator to be repowered with energy storage. The OCEI solicitation was conducted in coordination with East Bay Community Energy (EBCE), the CCA serving load in the Oakland area. EBCE procured the RA product from the same projects in PG&E's OCEI Preferred Portfolio. Therefore, PG&E's OCEI Application did not seek approval to count the OCEI Preferred Portfolio towards the AB 2514 goal. PG&E's IRP modeling does not include any of the OCEI resources.

System Reliability RFOs: In November 2019, the CPUC issued D.19-11-016, which takes a number of steps to address the potential for system RA shortages beginning in 2021, including ordering incremental electric system reliability procurement by all LSEs operating within the CAISO's balancing area to meet system RA needs for the period 2021–2023. D.19-11-016

[77] A.18-03-001, Application of PG&E for Approval of its 2018 Energy Storage Procurement and Investment Plan, filed March 1, 2018.

requires PG&E to make incremental procurement of 765.1 MWs[78] of system-level qualifying capacity. The Decision also requires that at least 50 percent of LSE resource responsibilities come online no later than August 1, 2021, at least 75 percent by August 1, 2022, and the remaining by August 1, 2023. PG&E issued its System Reliability RFO – Phase 1 on February 28, 2020 to solicit offers from participants for the purchase of eligible system RA to come online by August 1, 2021, and count towards PG&E's requirement. At the conclusion of the RFO PG&E submitted for CPUC approval seven agreements, together totaling 423 MW of incremental system RA to come online no later than August 1, 2021.[79] PG&E issued the System Reliability RFO – Phase 2 on July 10, 2020 to procure the remaining required MWs.

Information for Procurement Ordered in D.19-11-016 (2019 IRP Procurement Track): In response to the system resource adequacy (RA) procurement ordered in Decision (D.) 19-11-016, PG&E submitted a Tier 3 advice letter (Advice 5826-E) on May 18, 2020, seeking Commission approval of seven agreements to meet PG&E's August 1, 2021 requirement (Phase 1). The agreements were submitted confidentially to the Commission in PG&E Advice 5826-E. Table 17 below summarizes the project names, technology, MW contracted, and expected online dates for the projects that PG&E has entered into agreements with to meet its 2021 requirement.

[78] PG&E was informed on April 15, 2020 via ALJ Ruling that it is required to procure an additional 48.2 MW for CCAs and ESPs in its TAC area that chose not to self-provide their required portion of incremental system RA. 765.1 MW includes the original 716.9 MW for PG&E bundled customers plus an additional 48.2 MW of backstop procurement.

[79] See PG&E Advice Letter 5826-E, dated May 18, 2020.

Table 17 IRP Procurement Track Procurement Status

Counterparty (Project Name)	Technology	Commercial Online Date	Initial Delivery Date	Term (Years)	Size (MW)
Dynegy Marketing and Trade, LLC (MOSS100 Energy Storage)	Lithium Ion Batteries	7/18/2021	10/1/2021	10	100
Diablo Energy Storage, LLC (Diablo Energy Storage – Tranche 1)	Lithium Ion Batteries	7/18/2021	10/1/2021	15	50
Diablo Energy Storage, LLC (Diablo Energy Storage – Tranche 2)	Lithium Ion Batteries	7/18/2021	10/1/2021	15	50
Diablo Energy Storage, LLC (Diablo Energy Storage – Tranche 3)	Lithium Ion Batteries	7/18/2021	10/1/2021	15	50
Gateway Energy Storage, LLC (Gateway Energy Storage)	Lithium Ion Batteries	7/18/2021	10/1/2021	15	50
NextEra Energy Resources Development, LLC (Blythe Energy Storage 110)	Lithium Ion Batteries	7/18/2021	10/1/2021	15	63
Coso Battery Storage, LLC (Coso Battery Storage)	Lithium Ion Batteries	7/18/2021	10/1/2021	15	60

In addition, PG&E has launched Phase 2 of its System Reliability RFO (Phase 2) and expects to sign contacts in mid-December for resources to meet the 2022 and 2023 online date requirements. PG&E intends to file an advice letter requesting Commission approval of such contracts by the end of December 2020. That solicitation will complete PG&E's procurement obligation as directed in D.19-11-016.

Proposed New Near-Term Actions

PG&E will continue to procure energy storage needed to meet PG&E's 2020 IRP, which only includes energy storage needed to meet: (1) existing procurement requirements (e.g., AB 2514); or (2) other procurement proposals already made by PG&E (e.g., System Reliability RFOs). PG&E did not include assumptions about the procurement of energy storage to address future reliability or grid needs or to meet regulatory, CAISO, or legislative requirements, but acknowledges there may be additional storage projects required in the next 1–3 years.

Deviations from Current Resource Plans

The most comprehensive resource plan for energy storage in PG&E's territory is PG&E's 2020 Energy Storage Procurement Plan (filed March 2, 2020). However, this plan is only meant to encompass required procurement under AB 2514. All storage procurement outside of or beyond those targets was not included in that Application. For example, the results of the System Reliability RFO—Phase 1 were filed separately on May 18, 2020.

Key Barriers to Energy Storage

Cost Effectiveness of Storage vs. Traditional Grid Solutions: While battery costs are expected to decline over time, energy storage is still an expensive technology when compared to traditional grid infrastructure or generation today. In some cases, energy storage is precluded as a solution to grid needs due to PG&E's obligation to seek the most cost-effective grid solutions for its customers.

Uncertainty for Energy Storage Devices Providing Services Across Grid Domains: The competitiveness of many energy storage technologies is expected to improve with anticipated future price reductions in the cost of battery energy storage systems, improvements in operating efficiencies, increased duration of storage systems, and value-stacking through MUAs. The stacking of value streams across the wholesale markets, RA, transmission, distribution, and customer domains is critical to achieving cost-effective storage projects today. However, the rules and regulations for MUA storage to access those value streams are complex and, in some cases, insufficient, creating a need for further CPUC or CAISO action or planning and operational protocols/tools to avoid jeopardizing the reliability of the distribution grid. This includes the definition of "incrementality," appropriate compensation methodologies for resources, and cost recovery for utilities. Stakeholder initiatives at the CPUC and CAISO from the MUA working group and the Storage as a Transmission Asset initiative to ESDER 4 and Hybrid Resources are positive steps to removing these barriers.

Lack of Enhanced Visibility, Monitoring and Integrated Control Systems for Utility Operations to Ensure Grid Needs are Addressed and Fully Realize the Value of Energy Storage: As storage deployment and opportunities for multiple use applications increase, the complexity of utility distribution and transmission grid planning and operations will also increase. Enhanced utility planning, operational and communication systems and protocols will be required to: (1) maintain both transmission and distribution grid safety and reliability; (2) realize the maximum value of storage; and (3) validate storage operational performance for compliance and settlements. These enhanced measures will require integration of multiple transmission and distribution system planner and operator applications to not only validate storage performance but to also simplify management of the grid.

Maintaining Distribution Grid Reliability in MUA: The adoption of rules by the CPUC to guide the formation of MUAs for energy storage has taken California one step closer to providing equitable compensation for a variety of services that energy storage devices can provide. Inherent within these rules is a clear understanding that grid reliability services provided by energy storage systems must take priority over any other service.[80] The MUA working group discussed this issue, within the Ensuring Performance chapter, and recommended adopting a "dispatch primacy" principle to clearly set the boundaries to maintain distribution reliability. Still, challenges remain to turn these principles and rules into real-world

[80] D.18-01-003.

planning and operational processes and market design procedures that ensure distribution grid reliability. PG&E actively engaged with utility and industry stakeholders in the MUA working group to better define how these rules would be implemented in the future.

Recommendations for Commission Action and in Future IRPs

Energy storage should continue to be modeled as a candidate resource in the CPUC's capacity expansion modeling. To the extent feasible, multiple value streams should be considered, including energy arbitrage, avoided capacity costs, GHG reduction, and avoided transmission or distribution grid upgrades. A wide range of storage technologies should also be considered for future storage needs, including but not limited to, batteries, power to gas, pumped hydro, and vehicle to grid. The IRP process can be utilized in the future to determine the cost-effective levels of additional storage needed to meet the state's clean energy goals and maintain system reliability in 2030.

iii. Energy Efficiency

PG&E's current and future EE procurement activity is focused on soliciting for new third party-implemented programs in order to meet the CPUC's requirement that, by the end of 2022, each of the California IOUs administer an EE portfolio consisting of at least 60 percent third party-implemented programs.

TABLE 18
ENERGY EFFICIENCY – SUMMARY OF PG&E STUDY RESULTS, ACTIONS, AND RECOMMENDATIONS

Existing Near-Term Actions	• EE Request for Abstracts (RFA) and Request for Proposals (RFP) across multiple sectors (residential, commercial, industrial, agricultural, public) continuing to add new contracts with third-party programs are on track to achieve 60 percent third-party implemented programs by December 2022.
Key Barriers	None at this time.
Proposed New Near-Term Actions / Commission Direction	• Implementation of PG&E's suggested policy changes as reflected in the EE proceeding • Commission should implement PG&E's EE Business Plan to be filed in Q3 2021.
Deviations From Current Resource Plans	None at this time.
Recommendation for Future IRPs	None at this time.

PG&E has fully embraced the transition to a predominantly third-party implemented portfolio. PG&E has met the June 30, 2020 compliance target of 25 percent third-party programs and is on a path to meet the 40 percent target by the end of 2020, and to make substantial progress towards the 60 percent outsourcing target in advance of the December 2022 deadline.

PG&E designed its primary solicitation as a single solicitation across five sectors: Residential, Commercial, Industrial, Agricultural, and Public. While significantly more complex to manage than a sector-specific solicitation, PG&E recognized that the all-sector design would (1) most efficiently and effectively consolidate and streamline PG&E's EE program portfolio, and (2) minimize the transition period for new programs. The all-sector design provides maximum design flexibility to implementers and has enabled PG&E to be receptive to all strong third-party proposals. It enables PG&E to build its future portfolio around the best new programs focused on performance and cost-effectiveness, rather than merely recreating the existing portfolio structure with third-party program delivery.

In 2019–2020, PG&E worked closely with its Independent Evaluators (IE) and the Procurement Review Group (PRG) to complete the RFA and RFP for its all-sector solicitation. In addition, PG&E initiated a solicitation for non-resource Local Government Partner programs and completed a solicitation for Statewide Codes and Standards Advocacy.

In the first half of 2020, PG&E signed new third-party program contracts for SW Codes and Standards Advocacy, Local Government Partners (non-resource), the Industrial, Agricultural and Public sectors, and portions of the Residential and Commercial sectors. In addition to existing third-party programs, these new contracts enabled PG&E to achieve the 25 percent target for third-party implemented programs. In the second half of 2020, PG&E expects to sign new third-party program contracts across several sectors, including the remaining portions of the Residential and Commercial sectors, Statewide New Construction (Residential and Non-Residential), and Statewide Workforce Education and Training (K-12 and Career Workforce Readiness). These programs, as well as the Statewide Programs being launched by other IOUs, will enable PG&E to achieve the target of 40 percent third-party implemented programs.

Per D. 18-01-004, PG&E must achieve 60 percent third-party implemented programs by the end of 2022. PG&E expects to achieve that target through its funding of new statewide programs led by other IOUs and co-funded by all four California IOUs. The other IOUs are soliciting for many of those programs now, and other statewide programs will be solicited in 2021. Going forward, PG&E may conduct smaller, targeted solicitations to address any future EE portfolio needs as necessary.

PG&E's Energy Efficiency Business Plan ("Business Plan")[81] presents PG&E's annual energy savings and demand reduction forecasts, annual projected GHG emission reductions, budget forecasts, and projected cost effectiveness targets for 2018–2025 from EE programs in each of five customer or market sectors: Residential, Commercial, Public, Industrial, and Agricultural. In addition, its plans for these market sectors are complemented by four segments within its cross-cutting sector—Codes and Standards, Workforce Education & Training, Emerging Technologies, and Financing—that play a pivotal role in advancing its customers' pursuit of energy savings. Each Business Plan chapter describes the proposed intervention strategies and tactics for each sector in greater detail. The Business Plan describes how cross-cutting programs will be used strategically to support PG&E's portfolio across the five market sectors. During the period 2018–2025, EE may be called upon to provide new functions as a result of various resource planning proceedings at the Commission. As the phase-in of third-party implementation shifts the task of program design and delivery more to third parties, PG&E will retain responsibility to ensure that the contracted programs remain consistent with PG&E's approved strategies to achieve reliable energy savings.

Key Barriers to Energy Efficiency

None at this time.

Recommendations for Commission Action and in Future IRPs

PG&E continues to be guided by the vision and objectives detailed in the 2018–2025 Business Plan. That vision is a customer-centric EE portfolio that inspires customers and enables partners to eliminate unnecessary energy use by cost-effectively scaling EE and positioning it as a competitive grid resource to help meet the challenge of climate change.

PG&E is forecasting a cost effectiveness portfolio with the inclusion of Codes and Standards. However, without Codes and Standards, the portfolio Total Resource Cost in 2023–2025 does not meet the 1.25 required Total Resource Cost cost-effectiveness threshold established by the CPUC. There are several challenges that inhibit forecasting an EE portfolio that meets a 1.25 Total Resource Cost, while achieving energy savings targets and policy goals. These challenges are due in large part to:

- Diminished and unpredictable avoided costs
- Temporal misalignment of forecast development and external input finalization
- Conflicting objectives for EE portfolios
- Diminished availability of measures with significant, positive net benefits

[81] Application of PG&E for Approval of 2018–2025 Rolling Portfolio Energy Efficiency Business Plan and Budget, filed January 17, 2017. Available at http://prccappiiswc002/Docs/EnergyEfficiency2018-2025-RollingPortfolioBusinessPlan/Pleadings/PGE/2017/EnergyEfficiency2018-2025-RollingPortfolioBusinessPlan_Plea_PGE_20170117_399326.pdf .

As the portfolio administrator, PG&E plans to employ several tactics to manage the cost-effectiveness challenges and uncertainty its portfolio will face through 2025. However, cost-effectiveness challenges cannot be overcome by portfolio administrator action alone. Policy changes are also needed to ensure alignment of EE portfolios with California's EE policy objectives, including cost-effectiveness. PG&E discussed potential policy changes to address cost-effectiveness challenges in its response to the Administrative Law Judge's Ruling inviting responses to potential and goals policy questions; these changes will be discussed further in PG&E's filings throughout the EE proceeding and in the new Business Plan that the Commission has ordered PG&E, and each IOU, to submit in September 2021.

iv. Demand Response

PG&E continues to support demand response (DR) as a technology-neutral platform through which customers and aggregators can access markets and receive compensation for the provision of grid services. Moreover, PG&E continues to operate its own DR programs as well as support third-party DR market participation. PG&E facilitates third-party provider participation that directly bid into the CAISO markets with access to customer authorized data for CAISO registration, verification of customer eligibility, and settlement processes for such a mechanism.[82]

PG&E is at the mid-way point in its current DR funding cycle for programs covering the period 2018–2022.[83] In order to address the key barriers identified below, PG&E is engaging with stakeholders to address evolving issues.

Key policy discussions and trends that will shape how load responds to signals, and therefore the DR portfolio in the future include:

The size and role of PG&E as a DR provider is uncertain due to retail market fragmentation and the cost effectiveness of its programs. Sensitivities to PG&E's role include:

- **The role of third-party participation.** The CPUC is still evaluating the future of DRAM, as the provider of economic DR.

[82] This includes the Rule 24 tariff and the ongoing DRAM pilot.

[83] D.17-12-003 adopted each of the three IOUs Funding Applications for 2018-2022. As part of the extended cycle, each IOU was obligated to file a Mid-Cycle update by April 1, 2020 (AL-5799-E). Furthermore, the IOUs were ordered to file their next five (2023-2027) year funding Applications by November 1, 2021.

- **CCA DR program impact on IOU programs:** Per the Competitive Neutrality[84] framework, if a CCA offers a "similar" program as an IOU, the IOU program must cease to offer its own DR program to customers of that CCA, and remaining programs funds would need to be returned.
- **The capacity valuation of demand response.** The RA Proceeding at the CPUC has ushered in new proposals from CAISO on the value of DR. The final capacity valuation of DR could be a large sensitivity in the size of the portfolio and impact cost-effectiveness. Generally, DR programs should be cost-effective.
- **Prohibited Resources:** The restrictions on the use of fossil fueled backup generation has created some challenges, especially for traditional load drop DR resources.[85]
- **The technology that participates in demand response.** The underlying load impacts both the size of the portfolio and its performance in the CAISO market. While most of the load that participates in DR is behavioral, market trends indicate that we may see more automated and dispatchable load in the future.

A policy shift away from market integration to load management: PG&E recognizes there has been a waning interest in CAISO market participation due to challenges that are unique to demand response, coupled with an increased interest in more flexible rates, as suggested by the CEC in their Load Management Rulemaking.[86]

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[84] D.14-12-024 established a competitive neutrality cost causation framework by which IOUs would refrain from offering DR products and services to customers of third-party Load Serving Entities (LSEs), such as CCAs or ESPs, if these LSEs establish a "similar" DR program. Moreover, DR funds collected from customers who are with CCAs and ESPs that offer a "similar" DR program would need to be returned; thereby, reducing the pool of funds available to support the IOU DR program. While the IOUs jointly filed an implementation plan via AL-5353-E in August 2018, this filing has not been resolved by the Commission.

[85] CPUC Resolution E-4906 imposed restrictions on the use of prohibited resources for supporting DR events beginning January 1, 2019. The proceeding addressing this issue undertook a test year pilot to determine the level of baseline compliance and to test metering/logging capabilities for enforcement. A final determination on a permanent compliance framework is expected in the second half of 2020.

[86] The CEC initiated a stakeholder process to address load management. The *2020 Load Management Rulemaking* (Docket #19-OIR-01) will expand on efforts to increase efficiency and demand flexibility in California's electricity grid. The California Energy Commission (CEC) will revise the existing standards to promote a demand flexible electricity market, while ensuring that costs and benefits are equitable. The CEC will consider new tariffs, technologies, and other measures that are consistent with the need for increased demand flexibility to support a renewable and decarbonized electricity grid. How this stakeholder process will fit into the overall DR framework is unknown at this time.

New capabilities: The Lawrence Berkeley National Lab (LBNL) is undertaking its next DR Potential Study (Phase 4)[87] which may further assist in identifying potential demand flexibility and capabilities for not only DR but a broader segment of Distributed Energy Resources.[88]

[87] The DR Potential Study (Phase 4) is being undertaken by the Lawrence Berkeley National Lab (LBNL) based on data provided by the three IOUs. The study requested data from each IOU in the spring 2020 timeframe. The scope of information requested indicates that the study will assess more than just DR as information on other DERs were requested (e.g., EE, DG (including NEM, SGIP, EV), Rule 24). The study was mandated and is funded through the IOUs' 2018-2022 DR Funding Applications (A. 17-01-012 et al.) as adopted by D. 17-12-003. The Decision called for the three IOUs to collectively fund the study through an authorized budget of $5 million. The draft release of the DR Potential Study (Phase 4) is expected in late 2021.

[88] The expanded scope of the DR Potential Study (Phase 4), may help inform broader aspects of SB 350, which raised the RPS to 50 percent by 2030, called for doubling of Energy Efficiency deployment as well as a host of other activities associated with energy uses.

TABLE 19
DEMAND RESPONSE – SUMMARY OF PG&E ACTIONS, KEY BARRIERS, AND RECOMMENDATIONS

Existing Near-Term Actions	• Work with regulators on programs that can participate in CAISO and CPUC DR markets. • Continue PG&E's DR programs for residential and non-residential customers with an eyeing on modifications proposed in the Mid-Cycle Review. • Continue refining the DRAM pilot with third party demand response providers. • Track potential impacts of COVID-19 on the DR portfolio and communicate any changes in program implementation to the Commission, as needed.
Key Barriers	• Uncertainty with respect to PG&E's role as the demand response provider (DRP) or procurer. • Uncertainty with respect to the ability of DR resources to cost-effectively provide grid services. • Time-of-Use (TOU) rate roll-out in the next few years will affect the needs of the grid based on how customers respond or not respond to TOU price signals. • Enrolling EV and other BTM battery storage in demand response programs for smart charging. • Rapid technological advancement and changing customer preferences.
Proposed New Near-Term Actions / Commission Direction	• Approval of PG&E's mid-cycle filing by end of 2020. • Commission guidance for the next funding cycle (2023–2027). The next DR Application is due November 1, 2021.
Deviations From Current Resource Plans	The demand response in PG&E's Conforming Scenarios is aligned with the current DR funding cycle budget (2018–2022) authorization per D. 17-12-003. However, the actual MW load impact achieved for 2018 and 2019 fell short of the forecast in the 2018–2022 Application.
Recommendation for Future IRPs	Develop and refine the supply curve for DR resources to be evaluated in the IRP optimization based on the most recent Load Impact filing (4/1/2020).

Existing Near-Term Actions

Work with Regulators on Programs that can Participate in CAISO and CPUC DR Markets: PG&E has implemented DR programs in compliance with D.17-12-003, which authorized program designs and funding levels for the IOUs for the period 2018–2022. More recently, PG&E proposed a number of modifications in its Mid-Cycle filing to address its DR offerings. This included tightening eligibility requirements for its Base Interruptible Program (BIP),[89] facilitating residential enrollment for its Capacity Bidding Program (CBP), and ceasing to actively market its Smart Air Conditioner Program (SmartAC) due to high cost and attrition. In addition, PG&E continues to support the ecosystem of DR participants, aggregators and third-party program providers through a wide range of tools that ensure customers are able to participate in DR programs. Specifically, ongoing improvements have and continue to be made for improving the enrollment process for both utility and third-party offerings.[90]

Offer DR Programs for Residential and Non-Residential Customers: PG&E's DR portfolio includes programs such as the BIP and Peak Day Pricing (PDP) for non-residential customers, SmartAC and Smart Rate for residential customers and CBP and TOU rates for all customer classes. Customers can enroll in PG&E DR programs directly or through third-party aggregators (e.g., CBP and BIP). All PG&E customers are eligible to participate in DR programs with the exception that customers whose energy is procured by a CCA or other non-PG&E energy service provider are not eligible to participate in PDP, SmartRate or TOU programs. It should be noted that both PDP and SmartRate are Critical Peak Pricing, which are rate based. While these two Critical Peak Pricing are designed, funded, and managed outside of the DR funding process, the dispatch of PDP and SmartRate is administered by the DR Operations team.

Pilot the DRAM RFO with Third Party Demand Response Providers: PG&E is administering the DRAM RFO pilot through a pay-as-bid auction of monthly capacity for DR RA bid into the CAISO's energy market, where DR providers must meet the CAISO's must-offer obligations with customers in PG&E's service area. The pilot is designed to encourage third party DR providers to develop demand response programs that can spur innovation and growth of a competitive third-party market.

[89] PG&E subsequently withdrew its proposal on May 19, 2020, due to concerns expressed by parties and the broader impact it would have on certain participants during the economic uncertainty due to Covid-19.

[90] Third-party participation includes offerings by Aggregators that utilize PG&E's programs as well as third-party DR providers that utilize DRAM or simply leverage the rule 24 tariff. In the former, PG&E's BIP program allows for Aggregator participation in part but also includes direct PG&E enrollment. On the other hand, the CBP program is only offered through third-party Aggregators.

Key Barriers to Demand Response

Uncertainty with Respect to PG&E's Role as the DRP or Procurer: This uncertainty manifests in in two ways. First, CCAs are serving an ever-increasing portion of customers within the PG&E service territory and there is the possibility that the DA cap might be reevaluated.[91] Second, the future of the role of IOUs in providing DR versus third parties, such as DRAM, is an open question.

With respect to the first issue, under the Competitive Neutrality Cost Causation principle, a customer whose energy is procured by a CCA or an ESP is ineligible to participate in an IOU DR program if the CCA or ESP offers a program that is deemed by the Commission to be "similar" to the one offered by the IOU. Reductions in the number of eligible customers for PG&E DR programs could result in programs becoming less cost effective if indirect unavoidable costs (that pertain to systems, employees, education / training and Evaluation, Measurement and Verification) were to be refunded (i.e., bill credit) to the provider's customers.

As it relates to DRAM, the CPUC has yet to decide the future of this procurement mechanism. Since 2016 DRAM has been a pilot (mechanism) that has been extended several times. In its current form, the DRAM pilots are expected to be administered through 2023. The CPUC is undertaking its second evaluation of the DRAM pilot to determine if it should transition to a permanent mechanism, after which the Commission is expected to provide clarity on expectations about the role of IOU DR programs.

Uncertainty with Respect to the Ability of Demand Response Resources to Cost-Effectively Provide Grid Services: Additionally, grid needs are evolving away from system capacity and toward local capacity, flexible capacity, and ancillary services that are needed to support the transition to a cleaner grid. It will be important to determine which evolving grid needs DR is best suited to meet cost-effectively. This is important because the IOU DR programs are mandated to be cost-effective and the complexities associated with an evolving grid may require costly solutions in terms of program offerings and system administration. In addition, recent changes to the methodology for calculating Avoided Costs could will impact the value attributed to DR resources.[92]

Need for Alternative Rate Designs: For DR programs to provide the greatest value, they must be compatible and complimentary with an underlying rate design. DR programs will be most effective when paired with underlying rates that accurately reflect the time-varying nature of the cost of providing grid services. In certain instances, where the underlying rate

[91] Per CalCCA, there are 12 CCAs within PG&E's service territory that supported approximately 41 percent of PG&E's total load in 2019. SB 237 passed in 2018 added 4,000 GWh to the existing 24,000 GWh of load that could be served by DA. It also mandated that the CPUC file a report by July 2020 to determine whether DA should be further opened.

[92] D. 20-04-010 (2020 Policy Updates to the Avoided Cost Calculator).

design does not align with grid needs, DR programs can also be utilized as the mechanism to procure additional grid services and dispatched when needed by grid operators. Such an alternative rate design fits into the broader push for load management, which may rely on more real-time rate offerings that leverage automated technologies.

Enrolling EV and other BTM battery storage in demand response programs for smart charging: Many BTM DER technologies have the potential to provide grid services via DR by temporarily dropping or shifting load to help realign supply and demand, and/or reduce the customer's utility bill. These include battery systems, in EVs or stand alone. Smart charging of a battery can be utilized to maximize customer benefit, which may or may not align with maximizing benefit to the electric grid. If enrolled in a DR program, however, the battery is incentivized to dispatch when needed by the grid.

Rapid Technological Advancement and Changing Customer Preferences: An important recognition in DR program design involves consideration of technological advancement and customer preferences. These are critical as certain legacy technologies (e.g., direct load control) may no longer provide cost-effective resources. Moreover, customers' desire to embrace new technologies (e.g., Smart thermostats) and understanding behavioral changes (e.g., when are customer using resources) are critical in the development of DR offerings. A key challenge is staying ahead of these trends.

Recommendations for Commission Action and in Future IRPs

In the near term, to facilitate Demand Response procurement activity, PG&E desires that its mid-cycle filing made via AL-5799-E be approved by end of 2020 at the latest.[93] Furthermore, as part of the approval process or in tandem, the Commission should provide guidance for the next funding cycle (2023–2027) Application due November 1, 2021.

PG&E recommends that for future IRP modeling, the Commission and DR providers develop supply curves for DR products allowing DR resources to compete in the IRP optimization with other resources using consistent valuations.

v. Distributed Generation

Here, DG refers to customer-sited renewable generation installations – primarily rooftop solar PV systems. PG&E has a long history as the leading utility when it comes to solar DG.[94] PG&E supports customer adoption of solar and other DG technologies by implementing DG-specific tariffs and incentive programs, working to improve and streamline interconnection processes, and by providing customers DG-related educational and customer service resources.

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[93] The CPUC in D.16-09-056 had signaled its intent to release a Resolution (DRAFT) no later than September 2020.

[94] Smart Electric Power Institute (SEPA) 2019 Annual Utility Survey.

PG&E has also been active in developing best practices for incorporating DG into load planning and building codes and standards.

TABLE 20
DISTRIBUTED GENERATION – SUMMARY OF PG&E STUDY RESULTS, ACTIONS, AND RECOMMENDATIONS

Existing Near-Term Actions[(a)]	• Provide customer service infrastructure to implement Net Energy Metering (NEM) tariffs. • Administer or support DG and storage programs. • Streamline interconnection and facilitate incorporation of solar inverter technology. • Continue to integrate DG impacts into load planning and building codes and standards.
Key Barriers	• Incentives through the NEM tariff structure that are misaligned with DG's net value • Lack of visibility into DG generation data • Current utility operational systems are not yet capable of using advanced inverter technology to its fullest extent. • Unknown distribution operational impacts of high penetration levels of BTM PV • Lack of systems and protocols to achieve full visibility, monitoring and ability to identify and capture potential market benefits
Proposed New Near-Term Actions	Actively participate in upcoming CPUC NEM Reform proceeding to support sustainable customer-focused NEM tariffs
Deviations From Current Resource Plans	N/A (PG&E does not develop a resource plan for DG + BTM storage).
Recommendation for Future IRPs	• Evaluate DG in IRP as a candidate resource • Ensure consistent valuation between supply-side resources and DG. • Validate assumed DG generation profiles against metered data.

(a) PG&E did not make any separate forecast assumptions about solar PV that may be built as a result of future distribution deferral opportunities.

Existing Near-Term Actions

PG&E recently reached 500,000 bundled and unbundled customers with DG installed behind the utility meter. PG&E is supporting these and future DG customers through several existing and planned actions.

Provide Customer Service Infrastructure to Implement NEM Tariffs: NEM tariffs—which allow customers to receive monetary credits for electricity exported to the grid and use credits to offset charges for imported electricity—have spurred significant growth in DG adoption. The NEM tariffs and sub-schedules require specialized billing infrastructure to implement, dedicated staff with specialized training in safe generation interconnection, as well as educational and communication resources for customers and vendors due to the complexity of these tariffs. PG&E provides dedicated staff and billing infrastructure, as well as communications resources (including a call center dedicated to handling approximately 20,000 monthly calls from DG customers) to implement the NEM tariffs and sub-schedules. In addition to the call center, PG&E offers online educational tools and guides for customers who are considering or who have installed DG.

Administer or Support DG and Storage Programs: PG&E manages or supports DG Programs that will continue to facilitate the incorporation of DG and BTM storage into PG&E's electric system. These include:

- The Self Generation Incentive Program (SGIP) is administered by PG&E in its service area, which provides incentives to non-solar PV technologies such as fuel cells and wind, along with storage technologies. In 2020 SGIP was re-oriented to focus on providing customer resilience, and the program currently will extend through 2025.
- The CSI Multifamily Affordable Solar Housing (MASH) Program is administered by PG&E in its service area. This program is currently accepting applications and will fund installations through the end of 2021.
- The Disadvantaged Communities Single-family Affordable Solar Homes (DAC-SASH) program is administered by Grid Alternatives on behalf of all three IOU. PG&E supports the DAC-SASH program by reviewing final incentive packages, managing and providing data and processing payments.
- The Solar on Multifamily Affordable Housing (SOMAH) program is administered by the Center for Sustainable Energy on behalf of all three IOUs. PG&E supports the SOMAH program by providing participant data to the administrator and reviewing final incentive packages and processing payments. In addition, PG&E ensures safe interconnection of SOMAH generation and administers the supporting SOMAH tariff.
- PG&E also administers four community solar programs for both general market and Disadvantaged Communities. For general market these include the Solar Choice and Regional Renewable Choice programs, which are collectively capped at 272 MW of generation resources. For DACs these include the Green Saver and Local Green Saver programs, which are capped at 52.7 and 14.2 MW of solar resources, respectively.

Streamline Interconnection and Facilitate Incorporation of Smart Inverter Technology: PG&E has devoted significant resources to improving processes to reduce interconnection times. PG&E has published a system-wide refresh of PG&E's Integration Capacity Analysis results on a Data Portal available to DG installers. This portal provides improved visibility into locations where DG may be more readily interconnected without significant grid infrastructure upgrades. PG&E is actively participating in the Rule 21 Proceeding and Smart Inverter Working Group (SIWG), which are developing smart inverter standards, and monitoring smart inverter requirements through its interconnection processes. Additional on-going work in these initiatives continues to allow stakeholders to better understand the necessary technologies and systems to further advance Smart Inverter technology into utility grid operations.

Continue to Integrate DG into Load Planning and Building Codes and Standards: To facilitate appropriate electric system resource decisions, DG must be incorporated into LSEs' load planning, and DG's role in shaping load through building codes and standards must also be considered. PG&E has facilitated better incorporation of DG into statewide load planning and building codes and standards by:

- Dedicating resources to improving PG&E's system-level and geospatial DG adoption and generation forecasting to support PG&E's load and procurement planning;
- Participating in the CEC's IEPR Demand Forecasting process and CEC's Demand Analysis Working Group (DAWG) to improve statewide DG forecasting;[95]
- Hosting an annual Distribution Forecasting Working Group (DFWG) as part of the CPUC's Distribution Resources Plan Proceeding to better incorporate geospatial DG forecasts into IOU distribution planning;
- Developing and sharing information with CEC staff to inform Zero Net Energy (ZNE) requirements in California's Title 24 building code and incorporating the impact of those requirements in DG forecasting efforts;
- Developing an approved community alternative for builders taking advantage of Title 24 alternatives to mandatory rooftop solar; and
- Constructively participating in the NEM successor stakeholder discussions and proceeding(s).

PG&E plans to continue to work with the CEC, CPUC, DG providers, and other stakeholders to improve understanding of DG adoption trends and load impacts, and to assess and implement best practices for incorporating DG into load planning and codes and standards. In addition, PG&E will work with the CPUC and other stakeholders to more closely align the NEM tariff with appropriate cost causation principles.

[95] As PG&E explains in the "Assumptions" section of this IRP, PG&E uses lower estimates of annual generation output from rooftop PV in its service territory than the CEC IEPR forecast based on PG&E's modeling and validation against metered data.

Key Barriers to DG

Key barriers, including a misaligned NEM tariff structure and lack of visibility into DG generation data, should be addressed to enable the successful incorporation of future DG resources.

Incentives Through the NEM Tariff Structure That Are Misaligned with DG's Net Value: PG&E supports customers' choice to use DG to serve their energy needs, and NEM tariffs have played a role in incenting customers to adopt DG. As was documented in PG&E's communication to the CPUC and other stakeholders during the NEM Successor Tariff proceeding, PG&E remains very concerned that NEM currently provides incentives that are not proportionate to the net value of DG resources to the electrical system,[96] as is required by law.[97] This has resulted in DG adoption that is inconsistent with meeting system needs in the least cost manner, as demonstrated in RESOLVE modeling that shows that overall system costs increase with higher assumed levels of BTM PV adoption. Furthermore, under the past and current NEM Tariff structures, revenue recovery from the DG customers usually is less than the cost to serve them, and the DG customers cost the utility more to serve in comparison to the non-NEM customers under most of the circumstances. As a result, there is a disproportionate burden on customers who cannot, or choose not to, adopt DG to bear the cost for electric system infrastructure that supports all customers.

PG&E supports continued availability of rooftop solar as a viable option for our customers and looks forward to working with all stakeholders in near-term CPUC proceeding expected to result in a sustainable NEM tariff. Among other things, PG&E will focus on continuing to improve the customer experience of rooftop solar and other DG choices.

Lack of Visibility into DG Generation Data: In the California IOU service areas, DG vendors and customers are not required to provide sub-metered data on DG generation to the IOUs or to statewide planners. This lack of access to DG generation data creates challenges for customer understanding of NEM billing and may pose operational awareness challenges for utilities and planners as more DG, and particularly solar with variable generation, is incorporated into California's electrical system. Of increasing concern is the paucity of data regarding charge/discharge operation of BTM customer storage installation, particularly those installed in conjunction with rooftop solar.

Current Utility Operational Systems Are Not Yet Capable of Using Advanced Smart Inverter Technology to Its Fullest Extent: Through active engagement in the CPUC's SIWG,

[96] PG&E's Comments on Party Proposals and Staff Papers, September 1, 2015, NEM Successor Tariff, R.14-07-002 (hyperlink at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M154/K655/154655659.PDF).

[97] PUC Section 2827.1(b)(4)

PG&E has supported adoption of requirements that DG installations enable certain autonomous smart inverter functions.[98] However, further utility investment is required to deploy technology to connect to Smart Inverters and utilize DGs as a reliable grid resource in the future, especially if Smart Inverters are controlled at scale and in real-time across the electrical distribution system.

Unknown Distribution Cost Impacts of High Penetration Levels of BTM PV: Integration costs for rooftop solar are still unknown, especially at high penetration levels. As California moves forward with the CEC's ZNE codes for new homes, effective January 1, 2020, resulting in a high concentration of rooftop solar at new housing developments, these effects could have consequences that are not well understood at this time. The resulting integration issues associated with many residential circuits having high levels of solar installations are not well understood at this time.

Lack of systems and protocols to achieve full visibility, monitoring and ability to identify and capture potential market benefits**:** BTM PV systems are not metered by utilities for generation output. Visibility is restricted to the net usage (electric consumption net of solar generation) and exports to the grid that are measured by the utility revenue meter for customers participating in a NEM tariff. It is infeasible currently to collect data on the actual generation. While most vendors provide information to customers regarding their PV systems' production, there are no collection standards and quality requirements for that data. Furthermore, there are limited existing data collection, delivery protocols, and communication infrastructure that could be used make the data available to utilities, regulators, or market participants. Significant investment in data collection and communication infrastructure would be required before BTM generation could be reliably used for market participation that relied on measured data from the generator, which may be necessary for realization of BTM PV value for certain system benefits.

Recommendations for Commission Action and in Future IRPs

The Commission should use appropriate IRP-based avoided cost values to inform future NEM tariff design to actively participate in upcoming CPUC NEM reform proceeding to support sustainable customer-focused NEM tariffs.

The Fourth Amended Scoping Memo in Rulemaking 14-07-002, issued on March 29, 2018, indicated the Commission's intent to initiate, no later than January 1, 2019, a successor proceeding to revisit NEM tariffs. However, in D.20-06-058,[99] the commission signaled that a new rulemaking to consider changes to NEM policies is likely at the beginning of 2021 after the conclusion of a study evaluating the current interim NEM tariff. PG&E appreciates the Commission's commitment to re-examine NEM and suggests the Commission move swiftly to

[98] https://www.cpuc.ca.gov/General.aspx?id=4154.

[99] https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=342169723.

advance this discussion. PG&E looks forward to working with all stakeholders to ensure an outcome that supports sustainable choices for our customers who want rooftop solar and rooftop solar coupled with storage. As described in greater detail below, to ensure the sustainable deployment of DG, PG&E encourages the CPUC to evaluate DG as a candidate resource in the next IRP cycle, using consistent valuation across supply-side and demand-side resources. Including DG as a candidate resource in the IRP and using these results in the NEM tariff re-design discussions will help to ensure the NEM tariff sends the right price and quantity signals to the market so that California can achieve its GHG targets in the most cost-effective manner.

Evaluate DG in Integrated Resources Planning as a Candidate Resource: As PG&E has communicated previously in the IRP proceeding and as alluded to in the section "Proposed New Near-Term Actions" above, PG&E recommends that DG be modeled as a candidate resource rather than a load modifier in the next IRP process. This will help inform policy makers on the system-level costs and GHG emission reduction benefits of incorporating DG into CA's electrical system and will help the CPUC design NEM or other compensation mechanisms that appropriately reflect net climate benefits provided by DG.

Ensure Consistent Valuation Between Supply-Side and DG: Inconsistency raises costs and creates market inefficiencies, which may create challenges in meeting the state's GHG goals. Specifically, inflated pricing for some resources could result in non-cost-effective procurement for GHG abatement. This will ultimately result in increased rates, as lower cost abatement solutions will not be pursued and higher cost abatement solutions will not face market pressure to become more cost competitive. Furthermore, there is a risk that a higher GHG reduction cost in the electric sector may dissuade other sectors (e.g., transportation) from pursuing GHG reductions.

Validate DG Generation Profiles Against Metered Data: Limited validation has been performed of estimated DG generation profiles (particularly for BTM PV) against metered data. PG&E encourages the CPUC to ensure that the accuracy of DG generation profiles used for IRP modeling be assessed against metered data.

vi. Clean Transportation

PG&E is committed to increasing adoption of clean fuel vehicles, such as electric vehicles, hydrogen vehicles, and natural gas vehicles, in California to help the state meet its aggressive climate and clean transportation goals. The 2019 IEPR EV forecast was used for PG&E's conforming scenario includes expected deployment of over two million clean fuel vehicles in its service territory by 2030 and five million statewide, in furtherance of the Governor's goal regarding zero-emission vehicles. PG&E's existing and soon to be implemented customer offerings address key barriers to transportation electrification and EV adoption throughout its service territory. Not only will PG&E continue to implement its existing CPUC approved infrastructure programs and offer EV-specific rates and rebates in the near term, but the utility will also look for new opportunities aligned to PG&E's core capabilities to support the needs of EV drivers, including customers located in disadvantaged communities, through additional program and rate design and through technology research and development.

TABLE 21
CLEAN TRANSPORTATION – SUMMARY OF PG&E STUDY RESULTS, ACTIONS, AND RECOMMENDATIONS

Existing Near-Term Actions	• Grow charging infrastructure via PG&E's EV Charge Network Program. • Support MDV/HDV charging infrastructure via SB 350 Priority Review Project pilots and PG&E's EV Fleet Program. • Expand charging options through PG&E's EV Fast Charge Program • Expand charging infrastructure in state parks and schools through PG&E's EV Schools and Parks Program • Support increased EV adoption among low-and-moderate-income customers through PG&E's Empower EV program • Offer customers EV specific rates (e.g., EV-2A, EV-B, and Business EV (BEV)). • Offer customers Clean Fuel Rebates.
Key Barriers	• Lack of availability of charging infrastructure • Total cost of ownership • Lack of EV awareness or understanding • Grid impacts due to magnitude of expected EV load
Proposed New Near-Term Actions	PG&E is not requesting any additional actions in this IRP. However, PG&E encourages the Commission to approve the following actions, which will be filed in separate, future proceedings: • A decision on the Transportation Electrification Framework and approval of PG&E's associated Transportation Electrification Plan (TEP) • Approval of new LCFS Holdback Programs • Approval of post-prudency cost recovery for PSPS EV Resiliency Pilots • Approval of BEV Dynamic Rate Filing
Deviations from current resource plans	N/A (activities conform with all PG&E's recent CPUC clean transportation related filings).

PG&E is currently supporting EV adoption in its service territory through the following actions:

Grow Level 2 Charging Infrastructure Via PG&E's EV Charge Network Program: Continue implementation of the EV Charge Network Program directive that builds 4,500 level 2 EV charging stations at workplaces and multi-unit dwellings across Northern and Central California, installing a minimum of 15 percent of the chargers in DACs and providing additional rebates for sites in DACs.[100]

Support MDV/HDV Charging Infrastructure via SB 350 Priority Review Project Pilots and PG&E's EV Fleet Program: Continue implementation of the short-term SB 350 Priority Review Project pilots to encourage electrification outside the light duty vehicle sector among transit buses, school buses, and transport refrigeration units and provide a web-based EV charging information resource for residential EV drivers.[101] In addition, implement PG&E's EV Fleet Program by installing "make-ready" infrastructure for non-light-duty fleets at a minimum of 700 sites, and supplying charging for at least 6,500 vehicles.[102] Additional incentives will be provided to sites in DACs and to school and transit bus projects.

Expand Charging Options through PG&E's DC Fast Charging Infrastructure Program: Implement PG&E's EV Fast Charge Program by installing more than 50 sites for DC fast charging in corridor and urban sites, with 25 percent of sites located in DACs adjacent areas. Additionally, rebates will be provided to sites in DACs.[103]

Expand Infrastructure in State Parks and Schools: Implement PG&E's EV Schools and Parks program to install Level 2 and DC Fast Charging infrastructure at city and county parks, state parks and beaches, school facilities, and educational institutions within PG&E service territory.

Support Increasing EV Adoption Among Low-and-Moderate Income Customers through Empower EV: PG&E's Empower EV offers a rebate for a residential charger, and in some cases panel upgrade, as well as tailored marketing, education, and outreach to meet the needs of low and moderate income customers with a focus on communities in Fresno, San Jose, and Brentwood/Oakley. PG&E will tailor Marketing, Education, and Outreach to best serve these communities with a focus on providing multi-lingual resources and leveraging a diverse

[100] D.16-12-065.

[101] D.18-01-024.

[102] D.18-05-040.

[103] *Ibid.*

set of marketing channels. PG&E will also seek to partner with a program implementer with close ties to the communities served to administer the Empower EV program.

Offer Customers EV Specific Rates (e.g., EV-2A and EV-B): PG&E has two residential EV rates designed to promote EV charging during times consistent with grid needs, EV2-A and EV-B.[104] The rates are differentiated based on whether the EV charging has a dedicated meter. Both rate plans use an un-tiered TOU rate structure. They offer on-peak, partial peak, and off-peak energy prices. Additionally, PG&E now offers an EV rate for commercial customers. The BEV rate is being phased in throughout 2020, with basic functionality offered beginning May 1, 2020, and full functionality planned for October 1, 2020. PG&E offers two BEV plans, BEV-1 and BEV-2, based on charging installation load and combines a customizable monthly subscription charge with a time-of-use rate structure.

Offer Customers Clean Fuel Rebates: PG&E will continue to administer the Clean Fuel Rebate funded by the State's Low Carbon Fuel Standard program.[105] EV owners are rewarded for contributing to a cleaner energy future with their eligibility to receive a $800 Clean Fuel Rebate. PG&E plans to phase out the Clean Fuel Rebate program upon the launch of the statewide point-of-purchase Clean Fuel Rewards program.

Customer Education: PG&E has launched the Home Charger Information Resource Pilot that provides a step-by-step checklist and additional resources to aid customers in installing a home EV charging station. Additionally, PG&E's EV Savings Calculator is a customizable tool that disambiguates total cost of ownership and pools together information on EV models, rates, and incentives.

Key Barriers to Clean Transportation

The actions PG&E is currently taking to promote clean transportation will facilitate achievement of California's clean transportation goals. While the EV market continues to mature, barriers to EV adoption still remain to achieve the state's and PG&E's aggressive goals for expanding clean fuel vehicles. In the next 3 years, PG&E will target actions addressing the following barriers:

Lack of Availability of Charging Infrastructure: Access to EV charging infrastructure continues to be a major challenge across all vehicle types that contributes to range anxiety and hinders EV adoption. To date there are 30,355 public and private charging ports in California, 4,607 of which are Direct Current Fast Charging (DCFC).[106] Progress toward the state of

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[104] Resolution E-4508, PG&E's Advice 3910-E and 3910-E-A, August 27, 2012.

[105] D.14-12-083, Decision Adopting Low Carbon Fuel Standard Revenue Allocation Methodology for the Investor-Owned Electric and Natural Gas Utilities, dated December 18, 2014.

[106] Total public and private chargers in California from the Department of Energy's Alternative Fuels Data Center.

California's goal of 250,000 charging ports, including 10,000 DCFC, has been slow in part due to the significant costs associated with EVSE installation. PG&E is committed to accelerating investment in infrastructure to aid progress toward this goal and address this gap.

Total Cost of Ownership: While EV technology continues to advance and model types increase, EVs can still cost more than traditional internal combustion engine vehicles. In addition to the upfront vehicle costs, some vehicle types (e.g., medium- and heavy-duty EVs) are often required to charge at higher power. The resulting electricity costs, which can include demand charges, may be higher than alternatives, especially when utilization of the charging asset is low.

Lack of EV Awareness or Understanding: The decision to purchase an EV or convert a fleet involves awareness and understanding of new technology not limited to the vehicle itself but also the charging equipment, rate structures, and ways to maximize TOU benefits, as well as how to navigate the various incentive programs available to both residential and commercial customers.[107]

Grid Impacts due to Magnitude of Expected EV load: The statewide goal of 5 million passenger vehicles by 2030 and the complementary regulations for other transportation sectors will result in significant additional load to the grid which could exacerbate reliability issues. This will require new strategies and technologies, such as VGI, to successfully integrate future load of this magnitude.

Recommendations for Commission Action and in Future IRPs

As PG&E plans to further address EV adoption barriers in the next 1–3 years, we request that the Commission address the following actions:

Approval of PG&E's TEP: Under the Transportation Electrification Framework (TEF), PG&E will file a TEP outlining plans for transportation electrification investments and programs for the next five to ten years in support of statewide goals. Depending on the timing and content of the final TEF, PG&E plans to file a TEP and new TE program applications by early 2022.

Approval of new LCFS Holdback Programs: PG&E plans to file proposals for new LCFS-funded programs to support EV customers in 2020 and 2021 upon gaining final guidance in the Transportation Electrification Framework. These programs are an opportunity to use non-ratepayer funds to nimbly address emerging transportation electrification market needs with a focus on equity.

Approval of Cost Recovery for PSPS EV Resiliency Pilots: PG&E plans to implement pilot projects to investigate the feasibility of mobile and deployable EV Level 3 fast charging by

[107] PG&E's Prepared Testimony, Transportation Electrification SB 350 (A.17-01-022), submitted January 20, 2017.

the 2021 wildfire season, as required by the PSPS OIR, Decision 20-05-051 dated May 28, 2020. Each pilot is limited to $4M and the total cannot exceed $10M. Per the Decision, CPUC approval is not necessary for PG&E to deploy infrastructure. PG&E is authorized to seek ex-post prudency determination and recovery of costs involved for the procurement and deployment of this infrastructure in the next GRC.

Approval of BEV Dynamic Rate Filing: PG&E will file a proposal for a BEV dynamic rate by October 24, 2020, as directed by D.19-10-055 in response to PG&E's Commercial EV Rate Filing. The goal of this proposal is to explore the feasibility of dynamic rates as a tool to reduce the price of EV charging as well as understand the influence of dynamic rates on grid load management.

Consistent with PG&E's comments on the 2019 IEPR forecast (i.e., the load forecast used in this 2020 IRP), PG&E would like to encourage the CPUC and the CEC to include an assessment of carsharing electrification in future iterations of the electric transportation energy demand forecast.

The benefits of EV charging flexibility should be further explored in future iterations of the IRP. As the Commission considers even higher levels of EVs in future IRP cycles, flexible charging can ensure that clean transportation growth benefits renewable integration and does not exacerbate grid reliability issues. The Commission should therefore study the benefits to system reliability and reduced renewable curtailment as well as the costs of the associated grid and charging infrastructure required to facilitate flexible EV charging.

b. Diablo Canyon Power Plant Replacement

This section addresses the requirements related to DCPP retirement in the 2020 Standard LSE Plan filing requirement related to DCPP Replacement (D.19-04-040). In April 2020, the Commission approved Standard LSE Plan filing requirements related to DCPP Replacement. Per the filing requirements, all LSEs are required to:

1. "[P]rovide narrative description explaining which specific resources are planned to be procured to serve their load in the absence of DCPP[,]" and
2. "Consistent with decision D.19-04-040, those LSEs will have to demonstrate that new resources are suitable substitutes and are able to maintain system reliability without increasing GHG emissions (i.e., RECs alone do not satisfy this requirement, nor do natural gas resources)[.]"

PG&E appreciates the Commission's focus on new resources that are able to maintain system reliability without increasing GHG emissions. PG&E strongly supports efforts to conduct a comprehensive reliability assessment, which would consider the appropriate type and amount of renewable integration needed to reliably replace DCPP. PG&E urges the Commission to carefully review each LSE's IRP to ensure it sufficiently demonstrates how each LSE will meet future reliability and renewable integration needs.

As discussed in the GHG Emissions Results section, in the 46 MMT scenario PG&E's existing and planned resources are sufficient to meet its 2030 GHG compliance requirement. Therefore, PG&E has no additional planned procurement to serve its load in the absence of DCPP in the 46 MMT case beyond already planned procurement activities. Procurement that has already been planned, such as that for the 2019 procurement track, is largely comprised of dispatchable batteries that will aid in renewable integration and reliability. With the additional procurement described in this IRP, PG&E would also meet its 2030 GHG requirement in the 38 MMT scenario.

PG&E's portfolio includes a diverse set of resources that provide support to CAISO system reliability. After DCPP's retirement, PG&E's diverse resource portfolio will continue to contribute to CAISO system reliability. PG&E's 2030 planned portfolio provides 52 percent of its September RA requirement from flexible resources, including hydroelectric, pumped storage and battery storage.[108] Such non-emitting flexible resources are critical to renewable integration and system reliability.

[108] The 52 percent is derived by dividing the sum of the NQC values of PG&E's contracted and owned hydroelectric, pumped-storage and battery storage resources for September 2030 by PG&E's RA requirement (load and a 15 percent planning reserve margin) for the same month. See Appendix 2: System Reliability Calculator Tables, Table 25. The battery storage values are reduced for the CAM allocation of RA to other LSEs.

V. Lessons Learned

a. Reliability Assessment Before Preferred System Plan Decision

The Commission's 2018 IRP PSP did not identify a need for additional resources for System Reliability. Yet within months of this determination and outside the designed structure of the IRP planning process, the Commission determined that there was a significant need for additional capacity for System RA and ordered procurement of over 3,300 MW of new capacity as part of the 2019 IRP Procurement Track. This outcome represents a breakdown in the IRP process and raises questions about the viability and utility of the IRP process going forward.

The current IRP cycle represents an opportunity for the LSEs, the CAISO, and the Commission to work together to remedy the issues with the prior cycle and produce a reliable and cost-effective plan to address California's energy resource needs and emissions goals. It is critical that any procurement resulting from the IRP be based on the resources and need documented in LSE plans and an assessment by the CAISO to confirm that the amount and the type of resources identified in the IRP process are sufficient to meet its operational reliability needs (both at system and local levels).

Therefore, to close the current IRP, at a minimum, the following need to be completed:

- A robust reliability analysis with opportunities for stakeholders' review. The recent rolling blackout events of August 14–15, 2020 clearly demonstrate a need for an operational reliability assessment to confirm that the planned resources from the IRP process are sufficient to address operational reliability needs.[109]
- An assessment of local area resource needs due to OTC retirements. At a minimum, the analysis should confirm whether OTC replacement resources are needed in local areas (as defined by the CAISO) or at a sub-regional level due to transmission limitations (e.g., Path 26 rating).

b. Methodology for Future Reliability Procurement Allocation

Any incremental procurement resulting from the IRP process beyond each LSE's planned procurement should be allocated based on an LSE's reliability need (i.e., a "need-based allocation" method). The allocation methodology used in the 2019 Procurement Track did not satisfy that standard.

[109] In performing a robust reliability assessment, there are several key assumptions that must be evaluated in greater detail, as even minor changes in assumptions can have significant impacts on reliability and the resource build-out, including refining the counting rules for specific technology types, evaluating the validity of key assumptions (e.g., import limitations and large hydro optimization), and the timing (and location) of natural gas retirements.

A "need-based allocation" method links an LSE's future supply procurement obligations with its net contribution to the overall system procurement need and is therefore a better approach to ensure that each LSE is adequately planning to support system reliability. In contrast, the "peak load ratio" method fails as an allocation methodology because it does not provide appropriate incentives for LSE planning.

The Commission should use a stakeholder-driven process to develop a need-based allocation methodology for assignment of any incremental procurement (beyond what is already planned by the LSEs) to ensure that the allocation is fairly based on an LSE's contribution to the incremental system need.

In addition, if the results of a reliability assessment and the IRP proceeding indicate a need for large, capital-intensive resources (e.g., long duration storage), the CPUC must consider how such procurement will be accomplished among a large and diverse set of LSEs. This could include, for example, consideration of an expanded use of a CPE.

c. Assessment of Reliability and Cost Before Considering Lower 2030 GHG Target

A key element of the IRP proceeding is to ensure that the State is planning to meet its GHG reduction goals in a reliable and cost-effective manner. Although the current IRP includes a high-level estimate of transmission costs, without a robust reliability assessment (typically performed in the CAISO TPP process) a full understanding of the additional cost associated with integrating higher levels of renewables and inverter-based technologies is not available.

Before committing to a lower GHG target, and in light of the recent rolling blackouts, the Commission and stakeholders need to have a clear understanding of the reliability and cost implications. The work done so far does not address these questions sufficiently. In particular, PG&E is concerned that the results of the rate analysis associated with the 38 MMT GHG target fail to fully capture the investments needed in the transmission and distribution system and for renewable integration to reliably operate the system. The Commission should not adopt a 38 MMT target until these reliability and affordability issues have been resolved.

d. Lessons Learned Related to Modeling Assumptions

i. Reference System Plan Modeling Assumptions

In the process of developing this filing, PG&E tested several scenarios using the CPUC RSP RESOLVE model. The results of these scenarios point to the sensitivity of the CAISO resource build to certain assumptions and the importance of further vetting key assumptions. Two key assumptions are import capability and hydro capacity factors.

After comparing RESOLVE hydro capacity factors to the historic data from PG&E's fleet, PG&E ran a hydro sensitivity which allowed large hydro to generate approximately 7,800 GWh more per year. This results in a capacity factor of 43 percent compared to 30 percent in the RSP which is more reflective of both the PG&E fleet and CAISO historic data.[110]

Though the model builds nearly the same total quantity of capacity by 2030, it does so later and at significantly lower cost to customers, saving $475 million per year by 2030. Importantly, the results of this sensitivity also dramatically change the build out of the two specific resource types which the commission has required LSEs to discuss in their 2020 IRP plans: OOS wind and pumped storage. As shown in Table 22, with the hydro capacity factor sensitivity, the model completely removes out-of-state wind from its selected resources by 2030 and cuts new pumped storage capacity by more than half as compared to the RSP.

The significant impact to selected resources found in changing the hydro capacity factors suggests future IRP cycles should review this assumption more carefully. Further, if new OOS wind and pumped storage are only selected when hydro conditions differ significantly from historic conditions, additional analysis to defend the procurement of such resources is necessary to confirm those resources meet the least-cost best-fit requirement for procurement.

PG&E also ran a RESOLVE case intended to assess the sensitivity of the model to the import assumption. In this sensitivity, PG&E increased the out of state import capacity to 8,000 MW from the 5,000 MW assumption utilized in the RSP, a 60 percent increase. This level of imports is regularly seen across the CAISO, including during the 2019 peak day.[111] As shown in Table 22, with a 3,000 MW increase to the RSP import assumption, the resulting build from this sensitivity shows a greater need for out of state wind resources by 2030 but picks no pumped storage throughout the entire model horizon.

While PG&E acknowledges that the changing resource mix across the Western Electricity Coordinating Council (WECC) will impact the availability of imported energy going forward, we strongly urge the Commission to refine this assumption based on WECC-wide production cost modeling that accounts for baseload retirements and renewable growth across the WECC. These modeling results should be checked against actual recent CAISO import data, especially given the recent rolling blackouts. Without doing so, the IRP planning process is more likely to result in the development of a suboptimal resource mix, especially if specific resource procurement is adopted in subsequent procurement tracks.

More generally, such analyses highlight that current assumptions do not align with historic CAISO dispatch trends, nor are they sufficiently justified in how they differ. While PG&E

[110] See discussion in Study Results, Comparison to Reference System Portfolio.

[111] CAISO Peak Day Load History 1998 through 2019 https://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf. Related import data pulled from CAISO's OASIS database

recognizes the IRP process continues to evolve, refining such assumptions should be a priority going forward.

TABLE 22
RESOLVE SENSITIVITY RESULTS

Line No.	Selected New Resources (2030)	RSP	Hydro Sensitivity (+7,800 GWh/yr)	Import Sensitivity (+3,000 MW)
1	OOS Wind (MW)	606	0	1,500
2	Pumped Storage (MW)	973	434	0
3	Total In-State New Renewables (MW)	13,854	14,540	12,423
4	Total Resource Cost ($MM/yr)	$45,680	$45,205	$45,471

ii. Retirement of Transmission-interconnected Fossil and CHP Resources

The Commission's RSP no longer effectively accounts for age-based fossil retirements. For example, the RSP retires only 30 MW of fossil resources by 2030 in the 46 MMT case, all of which are peaker units. Meanwhile, the RSP retains all CHP resources. The CSP Tool then allocates these units across all LSE portfolios. PG&E views this low level of fossil retirement to be unlikely. The Commission's modeling should consider more realistic level of fossil retirements over the planning horizon.

e. Reallocation of RA Procurement Responsibility among LSEs

The CPUC System RA requirement allocation is based on the draft 2021 RA allocation and stays the same through 2030. PG&E's bundled load is expected to reduce with time and therefore its RA requirement will also reduce. Therefore, in the current IRP PG&E has been over-allocated the RA requirement implying that other LSEs are not planning for their appropriate share of the RA requirement. This issue needs to be addressed promptly to ensure that a fair "need based" allocation methodology can be developed for any future mandated procurement.

VI. Glossary of Terms

A.: Application

AAEE: Additional Achievable Energy Efficiency

AB: Assembly Bill

ALJ: Administrative Law Judge

Approve (an IOU, ESP or CCA Plan): the CPUC's obligation to approve an LSE's integrated resource plan derives from Public Utilities Code Section 454.52(b)(2) and the procurement planning process described in Public Utilities Code Section 454.5, in addition to the CPUC obligation to ensure safe and reliable service at just and reasonable rates under Public Utilities Code Section 451.

Balancing Authority Area (CAISO): The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

BART: Bay Area Rapid Transit

Baseline Resources: those resources assumed to be fixed as a capacity expansion model input, as opposed to Candidate resources, which are selected by the model and are incremental to the Baseline. Baseline resources are existing (already online) or owned or contracted to come online within the planning horizon. Existing resources with announced retirements are excluded from the Baseline for the applicable years. Being "contracted" refers to a resource holding signed contract/s with an LSE/s for much of its energy and capacity, as applicable, for a significant portion of its useful life. The contracts refer to those approved by the CPUC and/or the LSE's governing board, as applicable. These criteria indicate the resource is relatively certain to come online. Baseline resources that are not online at the time of modeling may have a failure rate applied to their nameplate capacity to allow for the risk of them failing to come online.

BioMAT: Bioenergy Market Adjusting Tariff

BioRAM: Bioenergy Renewable Action Mechanism

BIP: Base Interruptible Program

BPOT: Bundled Portfolio Optimization Tool

BTM: Behind the Meter

CAISO: California Independent System Operator

CalEPA: California Environmental Protection Agency

CAM: Cost Allocation Mechanism

Candidate Resource: those resources, such as renewables, energy storage, natural gas generation, and demand response, available for selection in IRP capacity expansion modeling, incremental to the Baseline resources.

Capacity Expansion Model: A capacity expansion model is a computer model that simulates generation and transmission investment to meet forecast electric load over many years, usually with the objective of minimizing the total cost of owning and operating the electrical system. Capacity expansion models can also be configured to only allow solutions that meet specific requirements, such as providing a minimum amount of capacity to ensure the reliability of the system or maintaining GHG emissions below an established level.

CARB: California Air Resources Board

CARE: California Alternative Rates for Energy

CBO: Community Based Organization

CBP: Capacity Bidding Program

CCA: Community Choice Aggregators

CCGT: Combined Cycle Gas Turbine

CEC: California Energy Commission

CEJA: California Environmental Justice Alliance

Certify (a Community Choice Aggregator Plan): Public Utilities Code 454.52(b)(3) requires the CPUC to certify the integrated resource plans of CCAs. "Certify" requires a formal act of the Commission to determine that the CCA's Plan complies with the requirements of the statute and the process established via Public Utilities Code 454.51(a). In addition, the Commission must review the CCA Plans to determine any potential impacts on public utility bundled customers under Public Utilities Code Sections 451 and 454, among others.

CHP: Combined Heat and Power

Clean System Power (CSP, formerly "Clean Net Short") Methodology: the methodology used to estimate GHG emissions associated with an LSE's Portfolio based on how the LSE will expect to rely on system power on an hourly basis.

CNS: Clean Net Short

CO2: Carbon Dioxide

Community Choice Aggregator: a governmental entity formed by a city or county to procure electricity for its residents, businesses, and municipal facilities.

Conforming Portfolio: the LSE portfolio that conforms to IRP Planning Standards, the 2030 LSE-specific GHG Emissions Benchmark, use of the LSE's assigned load forecast, use of inputs and assumptions matching those used in developing the Reference System Portfolio, as well as other IRP requirements.

CPE: Central Procurement Entity

CPSF: Clean Power San Francisco

CPUC or Commission: California Public Utilities Commission

CRVM: Common Resource Valuation Methodology

CSI: California Solar Initiative

D.: Decision

DA: Direct Access

DAC: Disadvantaged Communities

DAC-SASH: Disadvantaged Communities Single-family Affordable Solar Homes program

DAWG: Demand Analysis Working Group

DCFC: Direct Current Fast Charging

DCPP: Diablo Canyon Nuclear Power Plant

DER: Distributed Energy Resource

DG: Distributed Generation

DR: Demand Response

DSM: Demand-Side Management

DWR: California Department of Water Resources

E3: Energy and Environmental Economics

EBCE: East Bay Community Energy

ED: Energy Division

EE: Energy Efficiency

Effective Load Carrying Capacity: a percentage that expresses how well a resource is able avoid loss-of-load events (considering availability and use limitations). The percentage is relative to a reference resource, for example a resource that is always available with no use limitations. It is calculated via probabilistic reliability modeling. It yields a single percentage value for a given resource or grouping of resources.

Electric Service Provider: an entity that offers electric service to a retail or end-use customer, but which does not fall within the definition of an electrical corporation under Public Utilities Code Section 218.

ERRA: Energy Resource Recovery Account

ESA: Energy Savings Assistance

EV: Electric Vehicles

FERA: Family Electric Rate Assistance

FERC: Federal Energy Regulatory Commission

Filing Entity: an entity required by statute to file an integrated resource plan with CPUC.

Future: a set of assumptions about future conditions, such as load or gas prices.

GAM: Green Allocation Mechanism

GDP: Gross Domestic Product

GHG: Greenhouse Gas

GHG Benchmark (or LSE-specific 2030 GHG Benchmark): the mass-based GHG emission planning targets calculated by staff for each LSE based on the methodology established by the California Air Resources Board and required for use in LSE Portfolio development in IRP.

GHG Planning Price: the systemwide marginal GHG abatement cost associated with achieving a specific electric sector 2030 GHG planning target.

GRC: General Rate Case

GWh: gigawatt-hour

IEPR: Integrated Energy Policy Report

Integrated Resource Planning (IRP) Process: integrated resource planning process; the repeating cycle through which integrated resource plans are prepared, submitted, and reviewed by the CPUC

Integrated Resources Planning Standards (Planning Standards): the set of CPUC IRP rules, guidelines, formulas and metrics that LSEs must include in their LSE Plans.

IOU: Investor-Owned Utility

IRP: Integrated Resource Planning

kW: Kilowatt

kWh: kilowatt-hour

lbs.: Pounds

LCBF: Least Cost, Best Fit

LCOE: Levelized Cost of Energy

LDV: Light Duty Vehicle

LEV: Low Emission Vehicles

Load Serving Entity: an electrical corporation, electric service provider, community choice aggregator, or electric cooperative.

Load Serving Entity (LSE) Plan: an LSE's integrated resource plan; the full set of documents and information submitted by an LSE to the CPUC as part of the IRP process.

Load Serving Entity (LSE) Portfolio: a set of supply- and/or demand-side resources with certain attributes that together serve the LSE's assigned load over the IRP planning horizon.

Long term: more than 5 years unless otherwise specified.

Loss of Load Expectation (LOLE): a metric that quantifies the expected frequency of loss-of-load events per year. Loss-of-load is any instance where available generating capacity is insufficient to serve electric demand. If one or more instances of loss-of-load occurring within the same day regardless of duration are counted as one loss-of-load event, then the LOLE metric can be compared to a reference point such as the industry probabilistic reliability standard of "one expected day in 10 years," i.e. an LOLE of 0.1.

LSE: Load Serving Entity

MASH: Multifamily Affordable Solar Housing

MCE: Marin Clean Energy

MDV: Medium Duty Vehicle

MMBtu: Millions of British Thermal Units

MMT: Million Metric Ton

MUA: Multi-Use Applications

MW: Megawatts

MWh: megawatt-hour

NEM: Net Energy Metering

Net Qualifying Capacity: Qualifying Capacity reduced, as applicable, based on the following: (1) testing and verification; (2) application of performance criteria; and (3) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the California ISO pursuant to the provisions of this California ISO Tariff and the applicable Business Practice Manual.

Non-Modeled Costs: embedded fixed costs in today's energy system (e.g., existing distribution revenue requirement, existing transmission revenue requirement, and energy efficiency program cost).

Nonstandard LSE Plan: type of integrated resource plan that an LSE may be eligible to file if it serves load outside the CAISO balancing authority area.

NOx: Nitrogen Oxide

NSGC: New System Generation Charge

NSHP: New Solar Homes Partnership

O&M: operations and maintenance

OCEI: Oakland Clean Energy Initiative

OIR: Order Instituting Rulemaking

Ongoing CTC: Ongoing Competition Transition Charge

OOS: Out of State

O.P.: Ordering Paragraph

Optimization: an exercise undertaken in the CPUC's Integrated Resource Planning (IRP) process using a capacity expansion model to identify a least-cost portfolio of electricity resources for meeting specific policy constraints, such as GHG reduction or RPS targets, while maintaining reliability given a set of assumptions about the future. Optimization in IRP considers resources assumed to be online over the planning horizon (baseline resources), some of which the model may choose not to retain, and additional resources (candidate resources) that the model is able to select to meet future grid needs.

PCC: Portfolio Content Categories

P&G: Potential & Goals

P^3: Procurement Portfolio Planner

PCIA: Power Charge Indifference Adjustment

PCIA WG3: Power Charge Indifference Adjustment Working Group 3

PDP: Peak Day Pricing

Planned Resource: any resource included in an LSE portfolio, whether already online or not, that is yet to be procured. Relating this to capacity expansion modeling terms, planned resources can be baseline resources (needing contract renewal, or currently owned/contracted by another LSE), candidate resources, or possibly resources that were not considered by the modeling, e.g., due to the passage of time between the modeling taking place and LSEs developing their plans. Planned resources can be specific (e.g., with a CAISO ID) or generic, with only the type, size and some geographic information identified.

PM: Particulate Matter

PMM: Portfolio Monetization Mechanism

PPA: Power Purchase Agreement

PRM: Planning Reserve Margin

PSP: Preferred System Plan

Pub. Util. Code: Public Utilities Code

PV: Photovoltaic

QF: Qualifying Facility

QF/CHP Settlement: Qualifying Facility and Combined Heat and Power Settlement

Qualifying Capacity: the maximum amount of RA Benefits a generating facility could provide before an assessment of its net qualifying capacity.

R.: Rulemaking

RA: Resource Adequacy

RAM: Renewable Auction Mechanism

REC: Renewable Energy Credit

Reference System Plan: the Commission's integrated resource plan that includes an optimal portfolio (Reference System Portfolio) of resources for serving load in the CAISO balancing authority area and meeting multiple state goals, including meeting GHG reduction and reliability targets at least cost.

Reference System Portfolio: the multi-LSE portfolio identified by staff for Commission review and adopted/modified by the Commission as most responsive to statutory requirements per Pub. Util. Code 454.51; part of the Reference System Plan.

ReMAT: Renewable Market Adjusting Tariff

RF&U: Revenue Fee and Uncollectibles

RFO: Request for Offers

RPS: Renewables Portfolio Standard

RSBA: Reliability Services Balancing Account

RSP: Reference System Plan

SABR: System Average Bundled Rate

SADR: System Average Delivery Rate

SASH: Single Family Affordable Solar Homes

SB: Senate Bill

SCE: Southern California Edison Company

SDG&E: San Diego Gas & Electric Company

SGIP: Self-Generation Incentive Program

SIWG: Smart Inverter Working Group

SmartAC: Smart Air Conditioner Programs

SOMAH: Solar on Multifamily Affordable Housing program

Staff: CPUC Energy Division staff (unless otherwise specified).

Standard LSE Plan: type of integrated resource plan that an LSE is required to file if it serves load within the CAISO balancing authority area (unless the LSE demonstrates exemption from the IRP process).

T&D: Transmission and Distribution

TACBA: Transmission Access Charge Balancing Account

TMNBC: Tree Mortality Non-bypassable Charge

TOU: Time-Of-Use

TPO: third-party owned

TRBA: Transmission Revenue Balancing Account

U.S.: United States

UFE: Unaccounted for Energy

UOG: Utility-Owned Generation

UOT: Upper Operating Target

WECC: Western Electricity Coordinating Council

VII. Appendix 1: Bundled Portfolio Optimization Tool

BPOT builds on the CSP framework by adding standard capacity expansion functionality. Like the CSP calculator, BPOT is an Excel-based model. The current version uses OpenSolver to drive the capacity expansion optimization.

Model Description

The BPOT is structured as a linear program where an objective function is minimized subject to a set operational and/or policy constraints. In this instance, the model is given a specific bundled portfolio load forecast and existing set of non-emitting resources and asked to choose from a set of candidate resources the mix of new resources that minimizes total bundled generation and procurement costs while at the same time ensuring that the portfolio provides sufficient RPS and GHG-free generation to meet the state mandated RPS targets and the IRP-mandated 2030 GHG planning target and sufficient RA capacity to meet the bundled portfolio's RA requirement.

To run, the model needs, among other things, a defined set of candidate resources and an hourly energy price forecast that spans the study period. For purposes of the analysis the candidate resources were limited to those chosen at the system level by the RESOLVE model in the 38 MMT case. The model utilized the LCOEs from RESOLVE and all related assumptions including inflation rate, levelization period, discount rate, taxes and financing. Similarly, the model used the hourly price forecast developed from the 38 MMT RESOLVE model results (see Section 2 (Study Design)). The primary output of the model is the set of new resource additions (i.e., MW of resource capacity added in each year).

Model Components

<u>Objective Function</u>

The objective function is specified as the net present value of the annual portfolio costs over the study period. Annual costs include the costs of new resources added to the portfolio and spot market transactions needed to balance load summed over the study period (2020–2030).

<u>Constraints</u>

- RPS: existing GHG-free + new RPS generation >= annual RPS target
- Resource Supply: Existing GHG-Free + New Resource generation + market purchases = bundled load
- GHG: 2030 (CSP Tool-based) LSE emissions <= specified GHG planning target

<u>Other Key Inputs</u>

- Nominal LCOE by year for each new resource type
- Hourly CAISO energy price forecast spanning the study period
- Hourly generation shapes by resource type

- Hourly 2030 emission factors
- Monthly RA market price

Data Core

The model's primary data structure borrows directly from the CSP Calculator. For each year of the forecast, the following equations are specified for each hour:

Emissions are calculated as:

$GHG\ (MT) = \ Open\ Position\ (MWh)\ \times Emission\ Rate\ (\frac{MT}{MWh})$, where

$$Open\ Position\ (MWh) = \ Bundle\ Load\ (MWh) - Existing\ GHG\ free(MWh) - New\ RPS\ (MWh) - New\ storage\ (discharge\ or\ Charge)$$

Portfolio Costs are specified as:

$$New\ Resource\ Cost\ (\$) = New\ Resource\ (MWh) \times LCOE\ \left(\frac{\$}{MWh}\right)$$

$$Open\ Position\ Cost\ (\$) = Open\ Position\ (MWH) * Energy\ Market\ Price\ \left(\frac{\$}{Mwh}\right)$$

The model chooses the mix of new RPS and storage resources (MW) that minimizes the net present value of total portfolio costs (new resource and open position) over the forecast horizon while ensuring that all RPS and GHG constraints are satisfied.

VIII. Appendix 2: System Reliability Calculator Tables

TABLE 23
46 MMT CASE SYSTEM RELIABILITY CALCULATOR UNADJUSTED

[redacted]

TABLE 24
38 MMT CASE SYSTEM RELIABILITY CALCULATOR UNADJUSTED

[redacted]

TABLE 25
46 MMT CASE SYSTEM RELIABILITY CALCULATOR ADJUSTED

[redacted]

TABLE 26
38 MMT CASE SYSTEM RELIABILITY CALCULATOR ADJUSTED

[redacted]

IX. Appendix 3: PG&E DAC Programs

What follows are tabular explanations of PG&E's DAC Programs, Pilots, Investments, as well as PG&E's Income Qualified Programs, Pilots, and Investments.

TABLE 27
DAC PROGRAMS, PILOTS, AND INVESTMENTS

	Category	DAC Programs and Pilots, and Investments	Authority	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
A	Clean Transportation	EV Fast Charge	D.18-05-040		X	Distribution
	PG&E will pay for and build infrastructure from the electric grid to the charging equipment for public fast chargers, complementing state and privately funded initiatives. 25 percent of PG&E's 234 planned EV fast chargers will be in DACs. PG&E will offer a significant rebate towards the purchase of fast chargers for customers based in these areas.					
B	Clean Transportation	EV Fleet	D.18-05-040		X	Distribution
	PG&E will pay for and help customers install the electric infrastructure from the grid to the charging equipment at an estimated 700 fleet customer sites. PG&E will partner with school districts, transit agencies, delivery fleets and other business customers, which often rely on diesel for their fleets, which is a highly polluting fuel. 25 percent of the program budget will go towards investments in disadvantaged communities and offer additional incentives for those sites, and for school and transit bus fleets that serve the general public. The program will also provide a rebate on EVSE costs to DACs up to a program total of $10 million.					
C	Clean Transportation	EV Charge Network	D.16-12-065		X	Distribution
	Through its EV Charge Network program, PG&E aims to help accelerate the adoption of EVs in California by increasing access to charging. Partnering with business customers and EV charging companies, PG&E will install 4,500 Level 2 EV chargers at condominiums, apartment buildings and workplaces across northern and central California, including 15–20 percent of the chargers at sites in disadvantaged communities.					

<table>
<tr><th></th><th>Category</th><th>DAC Programs and Pilots, and Investments</th><th>Authority</th><th>PG&E Bundled Customer Only</th><th>PG&E Service Territory Wide</th><th>Cost Recovery</th></tr>
<tr><td rowspan="2">D</td><td>Clean Transportation</td><td>Empower EV</td><td>D.19-09-006</td><td></td><td>X</td><td>Distribution</td></tr>
<tr><td colspan="6">PG&E's Empower EV offers a rebate for a residential charger, and in some cases panel upgrade, as well as tailored marketing, education, and outreach to meet the needs of low- and moderate-income customers with a focus on communities in Fresno, San Jose, and Brentwood/Oakley. PG&E will tailor Marketing, Education, and Outreach to best serve these communities with a focus on providing multi-lingual resources and leveraging a diverse set of marketing channels. PG&E will also seek to partner with a program implementer with close ties to the communities served to administer the Empower EV program</td></tr>
<tr><td rowspan="2">E</td><td>Demand Response</td><td>DR Pilot Projects to Benefit DACs</td><td>D.17-12-003</td><td></td><td>X</td><td>Distribution</td></tr>
<tr><td colspan="6">Results from proposed demand response pilots should contribute to the creation of new demand response programs, or significant improvements to existing programs, that can be implemented widely to augment the economic and/or environmental benefits demand response yields for disadvantaged communities. Demand response can provide tangible environmental benefits to disadvantaged communities by reducing localized air pollution and other detrimental environmental impacts. The current DR pilot in Fresno incentivizes participating customers to shift their energy usage to off peak hours to help reduce their bill.</td></tr>
<tr><td rowspan="2">F</td><td>Solar and Community Renewables</td><td>Disadvantaged Communities – Single-Family Solar Homes</td><td>D.18-06-027</td><td></td><td>X</td><td>GHG Allowance proceeds; when funds are exhausted, PPP</td></tr>
<tr><td colspan="6">The program will be available to low income customers who are resident-owners of single-family homes in disadvantaged communities. This will provide up-front financial incentives towards the installation of solar systems for low income homeowners.</td></tr>
</table>

<table>
<tr><th></th><th>Category</th><th>DAC Programs and Pilots, and Investments</th><th>Authority</th><th>PG&E Bundled Customer Only</th><th>PG&E Service Territory Wide</th><th>Cost Recovery</th></tr>
<tr><td rowspan="2">G</td><td>Solar and Community Renewables</td><td>DAC-Green Tariff</td><td>D.18-06-027</td><td>X</td><td></td><td>GHG Allowance proceeds; when funds are exhausted, PPP</td></tr>
<tr><td colspan="6">This program will provide a 20 percent bill discount to customers in disadvantaged communities who meet the income eligibility requirements for the CARE and FERA programs.</td></tr>
<tr><td rowspan="2">H</td><td>Solar and Community Renewables</td><td>Community Solar Green Tariff</td><td>D.18-06-027</td><td>X</td><td></td><td>GHG Allowance proceeds; when funds are exhausted, PPP</td></tr>
<tr><td colspan="6">This program will allow primarily residential low-income customers in disadvantaged communities or in San Joaquin Valley pilot communities from the development of solar generation projects located in or near their communities and receive a 20 percent bill discount. The communities will work with a non-profit community-based organization or local government “sponsor” to organize community interest and present siting preference locations to the utility; the sponsor can also receive a bill discount for its efforts.</td></tr>
<tr><td rowspan="2">I</td><td>Storage</td><td>AB 2868 Behind-the-Meter Thermal Energy Storage Program</td><td>D.17-04-039</td><td></td><td>X</td><td>PPP</td></tr>
<tr><td colspan="6">A BTM thermal energy storage program to reduce peak demand by 2–5 MW by 2025. This program will target a portion of the incentives for customers in low income communities and align with the SJV pilots to electrify their water heating and shift that load to off-peak hours.</td></tr>
</table>

<table>
<tr><th></th><th>Category</th><th>DAC Programs and Pilots, and Investments</th><th>Authority</th><th>PG&E Bundled Customer Only</th><th>PG&E Service Territory Wide</th><th>Cost Recovery</th></tr>
<tr><td rowspan="2">J</td><td>Storage</td><td>SGIP Equity Budget</td><td>D.01-03-073
D.17-10-004</td><td></td><td>X</td><td>Distribution</td></tr>
<tr><td colspan="6">Provides rebates for qualifying customers to receive panel upgrades and whole home-sized energy storage systems to aid in resiliency. Program is targeted to vulnerable customers that reside in a high fire threat district or have experienced 2 or more Public Safety Power Shutoff events.</td></tr>
<tr><td rowspan="2">K</td><td>Workforce Education & Training</td><td>Connections</td><td>D. 18-05-014</td><td></td><td>X</td><td>PPP</td></tr>
<tr><td colspan="6">PG&E leverages its Workforce Education and Training (WE&T) efforts to support awareness of green careers in disadvantaged communities.</td></tr>
<tr><td rowspan="2">L</td><td>Workforce Education & Training</td><td>Career and Workforce Readiness Program</td><td>D.18-05-041</td><td></td><td>X</td><td>PPP</td></tr>
<tr><td colspan="6">PG&E was recently approved to lead the Career and Workforce Readiness program in partnership with the other IOUs to support disadvantaged workers who lack the EE expertise and resources to enter the energy workforce. [112]</td></tr>
</table>

[112] The term “Disadvantaged Worker” is defined as a person who (1) has a referral from a collaborating community-based organization (CBO), state agency, or workforce investment board; or (2) lives in a ZIP code that is in the top 25 percent in one or more of the five socioeconomic indicators as defined in the California Office of Environmental Health Hazard Assessment’s CalEnviroScreen Tool. These socioeconomic indicators are educational attainment, housing burden, linguistic isolation, poverty, and unemployment.

TABLE 28
INCOME QUALIFIED PROGRAMS, PILOTS, AND INVESTMENTS

<table>
<tr><th></th><th>Category</th><th>Low Income Programs</th><th>Authority</th><th>PG&E Bundled Customer Only</th><th>PG&E Service Territory Wide</th><th>Cost Recovery</th></tr>
<tr><td rowspan="2">A</td><td>Financial Assistance</td><td>CARE</td><td>D.17-12-009
D.17-05-013</td><td></td><td>X</td><td>PPP</td></tr>
<tr><td colspan="6">The CARE Program provides a monthly discount on energy bills for qualifying households throughout PG&E’s service area. To qualify for the CARE discount, a residential customer’s household income must be at or below 200 percent of Federal Poverty Guidelines or someone in the customer’s household is an active participant in other qualifying public assistance programs. In June 2020, 1,457,418 customers were eligible for the CARE Program and 1,509,766 were enrolled (104 percent). 30 percent of the customers enrolled in the CARE program reside in DACs.</td></tr>
<tr><td rowspan="2">B</td><td>Financial Assistance</td><td>FERA</td><td>Res. E-4808</td><td></td><td>X</td><td>Residential Distribution</td></tr>
<tr><td colspan="6">The FERA Program provides a monthly 12 percent discount on electric bills for qualifying households of three or more persons throughout PG&E’s service area. To qualify for the FERA discount, a residential customer’s household income must be between 200 percent plus $1 and 250 percent of Federal Poverty Guidelines, as required in D.04-02-057 and per Public Utility Code Section 739.1(f)(2) requires a single application form for CARE and FERA to enable applicants to apply for the appropriate assistance program based on their economic need. In June 2020, 169,219 customers were eligible for the FERA Program and 32,611 were enrolled (20 percent). 17 percent of the customers enrolled in the FERA program reside in DACs.</td></tr>
<tr><td rowspan="2">C</td><td>Financial Assistance</td><td>Relief for Energy Assistance Through Community Help (REACH)</td><td>PG&E 30+ year partnership with the Salvation Army</td><td></td><td>X</td><td>Shareholder and Charitable Contributions</td></tr>
<tr><td colspan="6">The REACH Program provides financial assistance for qualifying households throughout PG&E’s service area. To qualify for the REACH financial support, a residential customer’s household income must be at or below 200 percent of Federal Poverty Guidelines, must demonstrate an uncontrollable or unplanned change in their ability to pay their utility bill, must not have received REACH assistance within the past 18 months, and must have received a 15-day or a 48-hour disconnection notice. REACH has provided financial assistance to 27,000 households since 2014.</td></tr>
</table>

<table>
<tr><th></th><th>Category</th><th>Low Income Programs</th><th>Authority</th><th>PG&E Bundled Customer Only</th><th>PG&E Service Territory Wide</th><th>Cost Recovery</th></tr>
<tr><td rowspan="2">D</td><td>Low-Income Proceeding</td><td>ESA</td><td>D.17-12-009
D.17-05-013</td><td></td><td>X</td><td>PPP</td></tr>
<tr><td colspan="6">The ESA program provides income-qualified customers free energy-efficient home improvements that can help reduce their energy bills and improve their health, safety and comfort. Services can include weatherproofing and attic installation, LED lighting, and refrigerator, furnace or water heater repair or replacement. The ESA program is a direct install program available to income-qualified customers in PG&E's 48 counties. Since 1983 ESA has served over 2.1 million customers. 46 percent of the homes treated in the ESA program in 2019 were located in DACs.</td></tr>
<tr><td rowspan="2">E</td><td>EE Service</td><td>Mobile and Manufactured Homes Program</td><td>D. 18-05-041</td><td></td><td>X</td><td>PPP</td></tr>
<tr><td colspan="6">The program serves mobile and manufactured homes with direct install offerings focused on lighting, water usage, and HVAC. Recently, low cost measures, including duct replacement have been added.</td></tr>
<tr><td rowspan="2">F</td><td>EE Service</td><td>Multifamily Energy Efficiency Programs</td><td>D. 18-05-041
D. 17-12-009</td><td></td><td>X</td><td>PPP</td></tr>
<tr><td colspan="6">PG&E administers a suite of multifamily energy efficiency programs serving disadvantaged communities, such as the HVAC Cooling Optimizer Program that services heating and cooling equipment and the Multifamily Upgrade Program, which provides building shell, HVAC, and lighting retrofits. PG&E also administers a single point of contact that coordinates relevant energy efficiency programs, income-qualified programs, and other energy resource options (e.g. demand response, DG, rate options, and electric vehicles) for multifamily building owners</td></tr>
<tr><td rowspan="2">G</td><td>Education – EV</td><td>EV Educational Tools for DACs</td><td>D. 11-07-029
D.14-12-083
D.18-01-024</td><td></td><td>X</td><td>Distribution</td></tr>
<tr><td colspan="6">PG&E also offers electric rate plans tailored for EV customers and rebates for EV purchases. PG&E continues to launch more educational tools and resources to help our customers overcome barriers to adoption.</td></tr>
<tr><td rowspan="2">H</td><td>Solar and Community Renewables</td><td>MASH</td><td>D.15-01-027</td><td></td><td>X</td><td>Distribution</td></tr>
<tr><td colspan="6">Provides business solutions to offset the costs of installing new solar energy systems on multifamily affordable housing in California. MASH aims to improve the quality of housing, decrease energy use and lower costs for tenants. It also urges tenants to use high-performance solar systems that help protect California's environment.</td></tr>
</table>

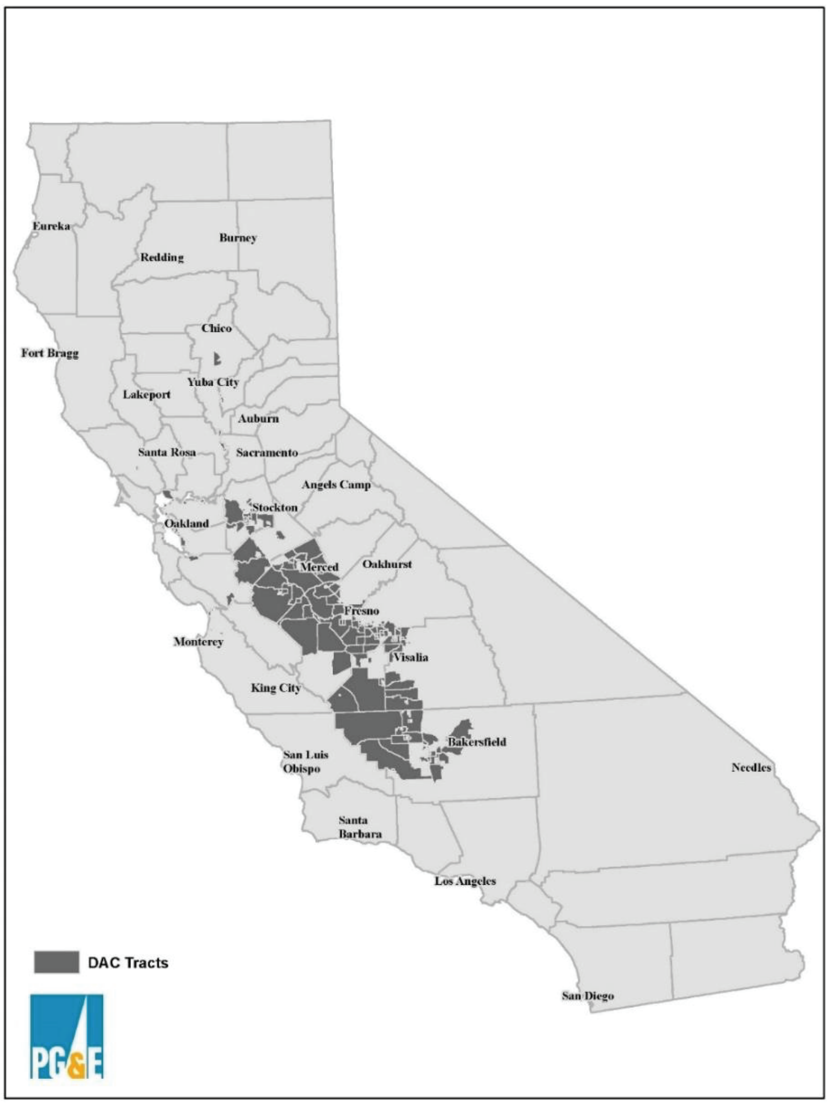
	Category	Low Income Programs	Authority	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
I	Solar and Community Renewables	SASH	D.17-05-013		X	Distribution
	Provides solar incentives on qualifying affordable single-family housing.					

X. Appendix 4: Map of DAC Areas in PG&E's Service Territory

As illustrated in Figure 2 below, PG&E displays the DACs in its service territory that correspond to the definition of a DAC specified in D.18-02-018:

[A] disadvantaged community shall be defined as any community statewide scoring in the top 25 percent statewide or in one of the 22 census tracts within the top five percent of communities with the highest pollution burden that do not have an overall score, using the most recent version of the California Environmental Protection Agency's CalEnviroScreen tool.

FIGURE 2
MAP OF DISADVANTAGED COMMUNITIES IN PG&E'S SERVICE TERRITORY



XI. Appendix 5: PG&E's Current Procurement Activity

TABLE 29
SNAPSHOT OF PG&E PROCUREMENT SOLICITATION ACTIVITIES

	Program	Description	Website
A	2020 System Reliability RFO - Phase 2	Purchase of energy resources which provide incremental System Resource Adequacy or load reductions to achieve an Initial Delivery Date no later than 8/1/2022 or 8/1/2023	2020 System Reliability RFO - Phase 2Opens in new Window.
B	Spring 2020 Bundled RPS Energy(REC) Sale Solicitation	Sales of bundled RPS-eligible energy and associated RECs generated in 2020 and 2021	Spring 2020 Bundled RPS Energy (REC) Sale SolicitationOpens in new Window.
C	2020 Spring Disadvantaged Communities (DAC) RFO	Purchase of energy from new solar resources located in Disadvantaged Communities	2020 Spring DAC RFOOpens in new Window. (Updated 6-15-2020)
D	2020 System Reliability RFO - Phase 1	Purchase of energy resources which provide incremental System RA to come online no later than 8/1/2021	2020 System Reliability RFO - Phase 1Opens in new Window. (Updated 3-16-2020)
E	2020 Distribution Investment Deferral Framework (DIDF) RFO	Procure a minimum of 4.4 MW of DERs	2020 DIDF RFO (Updated 03-03-2020)
F	December 2019 Bundled RPS Energy Sale Solicitation (Short-Term REC Sales)	Sales of bundled RPS-eligible energy and associated RECs generated in 2020	December 2019 Bundled RPS Energy Sale Solicitation (Short-Term REC Sales) (Updated 12-26-2019)
G	Request for Information: Clean Temporary Generation Products for Primary Voltage	This is NOT a Wholesale Electric Procurement Program. This program is different from the 2019 System Reliability RFO - DGEMS Phase	Self-register for Power Advocate Event 99855Opens in new Window. (RFI closes 2/4/20, Instructions within Power Advocate)
H	2019 Bundled RPS Energy Sale Solicitation	Sales of bundled RPS-eligible energy and associated RECs generated in 2019 and 2020	2019 Bundled RPS Energy Sale SolicitationOpens in new Window. (Updated 4-11-2019)
I	Regional Renewable Choice, also known as Enhanced Community Renewables.	Varies, up to 20 MW	Regional Renewable Choice Program (Updated 9-26-2019)