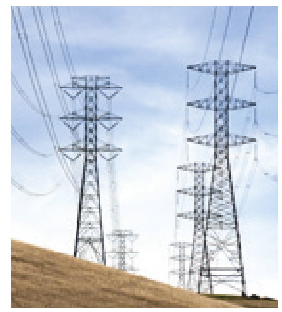
Integrated Resource Plan



2018

Prepared for the California Public Utilities Commission
August 1, 2018

PG&E

Together, Building
a Better California

TABLE OF CONTENTS

TABLE OF ACRONYMS

Acronym	Full Name
A.	Application
AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
BART	Bay Area Rapid Transit
BioMAT	Bioenergy Market Adjusting Tariff
BIP	Base Interruptible Program
BPOT	Bundled Portfolio Optimization Tool
CalEPA	California Environmental Protection Agency
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
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
CHP	Combined Heat and Power
CNS	Clean Net Short
CO_2	Carbon Dioxide
CPSF	Clean Power San Francisco
CPUC or Commission	California Public Utilities Commission
CSI	California Solar Initiative
CRVM	Common Resource Valuation Methodology
D.	Decision

Acronym	Full Name
DA	Direct Access
DAC	Disadvantaged Communities
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
ERRA	Energy Resource Recovery Account
ESA	Energy Savings Assistance
EV	Electric Vehicles
FERA	Family Electric Rate Assistance
GAM	Green Allocation Mechanism
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GRC	General Rate Case
GWh	gigawatt-hour
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Planning
IOU	Investor-Owned Utility
kW	Kilowatt
kWh	kilowatt-hour

Acronym	Full Name
lbs.	Pounds
LCOE	Levelized Cost of Energy
LDV	Light Duty Vehicle
LEV	Low Emission Vehicles
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 Tonne
MUA	Multi-Use Applications
MW	Megawatts
MWh	megawatt-hour
NEM	Net Energy Metering
NSHP	New Solar Homes Partnership
NOx	Nitrogen Oxide
NSGC	New System Generation Charge
OCEI	Oakland Clean Energy Initiative
Ongoing CTC	Ongoing Competition Transition Charge
O&M	operations and maintenance
OIR	Order Instituting Rulemaking
OOS	Out of State
OP	Ordering Paragraph
P&G	Potential & Goals
P3	Portfolio Planning Program
PCIA	Power Charge Indifference Adjustment
PDP	Peak Day Pricing
PM	Particulate Matter

Acronym	Full Name
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
R.	Rulemaking
RA	Resource Adequacy
RAM	Renewable Auction Mechanism
REC	Renewable Energy Credit
ReMAT	Renewable Market Adjusting Tariff
RFO	Request for Offers
RF&U	Revenue Fee and Uncollectibles
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
SmartAC	Smart Air Conditioner Programs
T&D	Transmission and Distribution

Acronym	Full Name
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
UFE	Unaccounted for Energy
UOG	Utility-Owned Generation
UOT	Upper Operating Target
U.S.	United States

LIST OF FIGURES

LIST OF TABLES

1. Executive Summary

A. Introduction

Pacific Gas and Electric Company appreciates the opportunity to participate in California's inaugural Integrated Resource Planning (IRP) process. The IRP will, among other things, help parties understand how load serving entities (LSE) plan to shape their future energy portfolios to meet the state's clean energy goals in a reliable and cost-effective manner. The promise of the IRP, as a new approach to electric-sector planning, is that can transition California away from specific and siloed resource mandates towards a true least-cost approach to meeting the state's greenhouse gas (GHG) emissions reduction goals. Ultimately this transition will be critical to the sustainability of California's climate policies and the state's continued environmental leadership position. PG&E recognizes that the 2017-2018 IRP cycle is a process design opportunity (i.e., a "proof of concept" cycle) that will be built upon in future cycles to achieve the truly integrated planning vision set forth in Senate Bill 350.

The inaugural IRP process introduces new constraints and considerations into the planning process. While the previous Long-Term Procurement Plan cycle focused primarily on reliability and the need for flexible resources, the California Public Utilities Commission's (CPUC or Commission) 2017 IRP Reference System Plan (RSP) did not identify any system reliability need through 2030.[1] Instead, a new constraint on GHG emissions was introduced for the electric sector and electric LSEs, along with a new methodology – the Clean Net Short (CNS) methodology—for calculating GHG emissions at the LSE level. New considerations for disadvantaged communities (DAC) have also been introduced to the planning process. Furthermore, the IRP establishes a framework for evaluating supply- and demand-side resources in the same planning process.

In addition to these new modeling constraints and public policy goals, California's expansion of retail choice, driven by growth in distributed generation (DG), the expansion of Community Choice Aggregators (CCA), and the potential for Direct Access (DA) reopening, adds considerable fragmentation to long-term electric sector planning. For LSEs, future retail loads have become highly uncertain. For the CPUC, the inclusion of many more LSEs into the planning process creates challenges that did not exist just a few years ago. Other ongoing Commission proceedings (e.g., Power Charge Indifference Adjustment (PCIA) Order Instituting Rulemaking (OIR), Resource Adequacy

1 This determination needs to be validated through the CPUC's production simulation modeling. Additionally, future IRP cycles should better consider how fossil retirements may impact system reliability.

(RA) OIR) are considering fundamental changes to the ways LSEs operate and the ways in which costs and benefits are allocated across customers who are served by different LSEs, furthering the uncertainty in the planning horizon. Furthermore, multiple other proceedings are impacted by the IRP, and PG&E encourages the Commission to ensure alignment to help the state achieve its ambitious GHG targets while weighing affordability and reliability challenges.[2]

For this first IRP cycle, PG&E commends the Commission for establishing LSE filing requirements that ensure all LSEs are integrated into the long-term planning process, while allowing flexibility for LSEs to consider their own unique planning considerations through the use of alternative scenarios.

B. Key Takeaways

PG&E summarizes the following key takeaways based on the scenarios assessed:

1. PG&E has included three scenarios: the Conforming scenario required by the Commission; a Preferred scenario based on PG&E's internal load forecast with increased load shift to CCAs and higher EV levels; and an Alternative scenario to examine the impacts of the Green Allocation Mechanism and Portfolio Monetization Mechanism (GAM/PMM), submitted by PG&E, Southern California Edison Company and San Diego Gas & Electric Company (collectively, the "Joint IOUs") as proposed in the pending PCIA Rulemaking (R.) 17-06-026.[3]
2. Past and future retail load shift to distributed generation and CCAs, as well as continued growth in energy efficiency, leads to declining bundled service loads for PG&E between now and 2030. PG&E attempts to sell its long positions, consistent with its obligations under the Bundled Procurement Plan (BPP), however for

---

2 As an example, the CPUC is actively considering the roll-out of default time of use (TOU) rates for residential customers in the 2018 Rate Design Window proceeding, while the Distribution Resources Plan proceeding identifies optimal locations for the deployment of distributed energy resources (DER). At the same time, the CPUC is considering IOU General Rate Cases (GRC) that include investments needed to support the deployment and value-realization of DERs. There are also electric vehicle (EV)-related proceedings to secure the investments needed to expand the state's EV charging infrastructure, while demand response (DR)-related proceedings evaluate how to leverage the flexible charging capabilities of EVs. The CPUC has also indicated its intent to soon reexamine the net energy metering (NEM) compensation scheme. The CPUC realizes the value in utilizing a "crawl, walk, run" approach to these myriad changes and has deployed many pilots (e.g., the San Joaquin Valley Disadvantaged Communities Project, Electric Program Investment Charge pilots) to learn and later scale promising opportunities.

3 See, Joint IOUs' Prepared Testimony, dated April 2, 2018, in R.17-06-026 (hyperlink at: https://www.rtoinsider.com/wp-content/uploads/PGE-CCA-filing.pdf).

certain products and periods of time there are no buyers. Therefore, for purposes of this IRP, PG&E is modeling its energy sales primarily as California Independent System Operator (CAISO) market sales, except for approximately 2,000 GWh/year of RPS eligible energy sales. Due to this modeling choice, the GHG-free attributes of additional long positions accrue to PG&E's bundled load in the calculation for the Conforming and Preferred scenarios.[4]

3. PG&E envisions a future with at least two million clean fuel vehicles in its service territory by 2030, and at least five million such vehicles statewide, in furtherance of Executive Order B-48-18 issued by the Governor on January 26, 2018 relating to zero-emission vehicles. This adds additional load to PG&E's system sales in the Preferred scenario as compared to the Conforming scenario which utilized the 2017 Integrated Energy Policy Report (IEPR) load forecast. Without any adjustment to the electric sector and LSE GHG planning targets, these higher loads increase the effective stringency of the IRP and may create disincentives for transportation electrification, contrary to legislative and state agency intent. While PG&E is not seeking adjustments to GHG planning targets in this inaugural IRP, it believes this is an important policy matter for state agencies to resolve in the next round of IRP given California's ambitions for the deployment of electric vehicles.
4. In planning for the change in bundled load due to the shift of bundled customers to CCAs, PG&E follows the Commission's leadership in Decision 18-02-018, which established consistent GHG planning targets for all LSEs within a distribution utility service territory, even as load migrates among LSEs. Building on this principle of maintaining a level playing field, as PG&E's bundled load share declines in PG&E's Preferred scenario, PG&E proposes a downward adjustment to its LSE GHG emissions benchmark to maintain the Commission's load-share-based methodology. PG&E did not make any adjustments to its GHG emissions benchmark because of higher electric vehicle loads. This assumption is only temporary until the California Air Resources Board (CARB) and the CPUC have resolved this important policy issue.
5. PG&E will continue to offer Distributed Energy Resource (DER) programs, and programs targeted in DAC, while recognizing that PG&E's role may evolve in the future as other LSEs provide electric service to more customers in PG&E's service territory.

4 In reality, some of these future energy sales of GHG-free energy may be via forward sales where the counterparty would then be able to include the GHG-free attributes in their own LSE IRPs. Given significant uncertainty in the market demand for these products, uncertainty in the outcome of the PCIA OIR, and the challenge of showing a transfer of attributes among LSEs in this round of the IRP, PG&E believes this modeling assumption is appropriate.

6. Under both the Conforming and Preferred scenarios, PG&E has no incremental procurement need for new Renewables Portfolio Standard (RPS) or GHG-free resources through 2030; PG&E can meet its 2030 GHG planning target with its existing GHG-free resource portfolio and resources added to comply with existing mandates. PG&E is not seeking any additional procurement authority under its Preferred scenario.
7. If the Commission adopts the Joint IOUs' GAM/PMM proposal in the PCIA OIR proceeding, PG&E's portfolio need changes significantly, and PG&E would have a near-term need for RPS and RA procurement. It is PG&E's strong preference for the Commission to adopt the GAM/PMM proposal, as submitted in Prepared Testimony on April 2, 2018. However, due to the current regulatory uncertainty associated with the outcome of the PCIA OIR, PG&E has included this case as an Alternative scenario rather than its Preferred scenario.
8. If the GAM/PMM proposal is fully adopted by the Commission in its final decision, PG&E plans to seek procurement authorization prior to its next IRP. As described in more detail below, PG&E would seek authorization to add approximately 4,800 MW of incremental RPS resources between 2024 and 2030, the solicitation of which would need to start within the next year.[5]
9. Future IRP cycles should:
    a. Establish a standardized framework to evaluate air pollutant emissions and fairly determine responsibility of emissions for resources located in DACs;[6]
    b. Incorporate DERs as candidate resources to ensure a truly optimal, least-cost approach to meeting the state's clean energy goals; and
    c. Further expand interagency alignment regarding load forecasts, economic retirement of fossil resources, GHG planning targets, and inter-sector GHG crediting.

C. Study Design

To develop its IRP, PG&E designed a study approach that addresses the key drivers of PG&E's bundled portfolio. Specifically, PG&E's Preferred and Alternative scenarios start with the 2017 IEPR forecast, and then incorporate updated load adjustments for continued CCA growth, distributed generation, and energy efficiency, future load

5 PG&E would seek a technology-neutral procurement process to select the least-cost best-fit resources to fulfill PG&E's RPS compliance requirements. Given that bid prices and market value will differ between the planning and procurement stages, PG&E might not end up procuring the specific levels of each RPS technology modeled in the Alternative scenario.

6 PG&E recommends a CNS methodology to forecast system-level air pollution. This methodology presents a coherent method to estimate system emissions for multiple emission types (GHG, NOx, $PM_{2.5}$) that result from an LSE's hourly use of fossil generation to serve its load.

increases from transportation electrification, and potential future regulatory reforms related to the appropriate allocation of utility procurement costs (specifically, the Joint IOUs' GAM/PMM proposal) that may impact PG&E's resource plan.

For both the Preferred and Alternative scenarios, PG&E utilized its internal forecast. PG&E's internal forecast utilizes the most up-to-date data on sales, weather, economics, and solar PV penetration, and reflects likely policy drivers. Thus, PG&E believes its internal forecast constitutes the best available estimate of the impact of load and load modifiers on long-term bundled sales.

The scenarios developed were then tested against PG&E's RPS compliance requirements, the IRP's LSE GHG target (measured via the CNS methodology), and other key bundled portfolio requirements such as system RA needs. Table 1 summarizes the three scenarios considered in PG&E's LSE IRP.

TABLE 1
PG&E'S 2018 IRP SCENARIOS

Line No.	Scenario	Key Changes vs. Conforming Scenario	PG&E Bundled Service Load (2030)	PG&E GHG Emissions Benchmark (2030)
1	Conforming Scenario[(a)]	n/a	34,187 GWh	6.07 MMT
2	Preferred Scenario	Updated CPUC Energy Division's electric vehicle (EV) assumptions from 3.3 million to 5.0 million in California by 2030; Higher system load due to PG&E's EV goals that align with the 5 million systemwide EVs; More CCA load growth in PG&E's territory; and, Other changes to load such as energy efficiency and DERs.	33,784 GWh	5.50 MMT[(b)]
3	Alternative Scenario	Same changes as Preferred; PG&E's bundled RPS and GHG-free large hydroelectric portfolio is reduced due to GAM-based allocation to other LSEs; and, RA capacity reductions via PMM auctions of RA.	33,784 GWh	5.50 MMT

(a) See Section 2 for a description of limited deviations from the RSP in PG&E's Conforming scenario.

(b) See Section 2 for a description of the GHG emissions benchmark adjustment.

To assess the need for incremental resource investments, PG&E performed the following steps for each of the three scenarios described above:

1. **Establish assumptions to be used in the analysis**: Includes PG&E's bundled load forecast, CAISO system-level load, the CAISO resource mix, and the market price forecasts;
2. **Determine incremental LSE resource needs**: Compare PG&E bundled service load and resource forecast against key IRP constraints (including RPS, the 2030 GHG target, and forecasted RA requirements); and
3. **If necessary, acquire least-cost new resources**: If Step 2 shows a need for additional resources, determine PG&E's optimal mix of resource additions.

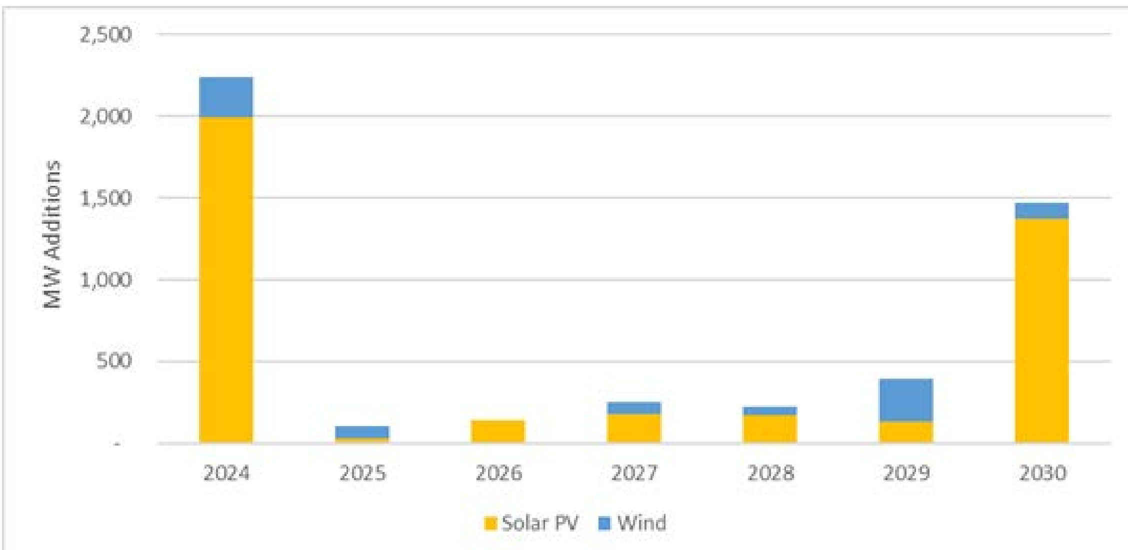
D. Study Results and Preferred Portfolio

PG&E has no incremental RPS or GHG-free procurement need through 2030 in two of the three scenarios considered. Based on the scenarios analyzed, only in a future in which the Joint IOUs' GAM/PMM proposal in the PCIA OIR is adopted (i.e., the Alternative scenario) does PG&E anticipate an incremental procurement need for new RPS and GHG-free resources by 2030.

PG&E has selected a Preferred portfolio that utilizes its internal load and load modifier assumptions and furthers the Governor's statewide goal of five million zero-emission vehicles in California by 2030. This portfolio includes continuation of near-term procurement and sales activities through existing Commission-authorized programs or pending requests before the Commission of solicitations, programs, and tariffs for renewable energy, energy storage, demand response, energy efficiency, and distributed generation. PG&E assumes some reform to the PCIA in this scenario, and has used the market-based inputs PG&E has advocated for in the PCIA OIR to forecast the PCIA market price benchmark. Thus, PG&E's average bundled service customer generation rates assume the PCIA cost shift has been reduced. Given PG&E's existing resource mix, and the significant level of existing and future load departure modeled, PG&E's Preferred portfolio shows no incremental procurement need for RPS or GHG-free resources through 2030. Therefore, PG&E is not requesting authority from the Commission to procure any new resources in this proceeding.

While PG&E strongly supports the Joint IOU's GAM/PMM proposal in the PCIA OIR, the Alternative scenario was not selected as PG&E's Preferred scenario due to the current regulatory uncertainty associated with the outcome of the PCIA OIR. However, given that the implementation of the GAM/PMM proposal would have a dramatic effect on PG&E's resource plan, PG&E has included this scenario as a sensitivity. In this scenario, PG&E will need additional RPS resources starting in 2024 and would have a need for GHG-free resources in order to meet its 2030 LSE GHG planning target. This scenario shows PG&E adding approximately 4,800 MW of renewable resources to meet its RPS compliance target and its LSE GHG emissions benchmark. Figure 1 shows the incremental supply-side resource additions in the Alternative scenario. These resources are in addition to the resources of existing contracts or generic positions associated with the Commission's mandated procurement.

FIGURE 1
INCREMENTAL SUPPLY-SIDE BUNDLED PORTFOLIO RESOURCE ADDITIONS IN PG&E'S ALTERNATIVE SCENARIO[a]



(a) The graph presents incremental resources in addition to existing and planned resources in PG&E's Preferred scenario.

In this IRP, PG&E's open RA position is assumed to be met with RA market purchases; however, PG&E notes that economic retirements of gas plants or other market or grid conditions may drive future reliability or other needs and that energy storage and/or renewable resources may be an economic alternative to meet some of these needs. PG&E's 2018 IRP only considers energy storage needed to meet existing procurement requirements (e.g., Assembly Bill (AB) 2514, CPUC Resolution E-4909) or other procurement proposals already made by PG&E (e.g., AB 2868). 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.

PG&E's Action Plan focuses on describing its planned near-term activities over the next 1-3 years, which are the same for PG&E's Conforming and Preferred portfolios. PG&E

will continue to procure RPS resources and energy storage based on existing compliance obligations, including procurement mandated regardless of IOU need. PG&E will continue to offer a suite of demand-side management programs and tariffs for energy efficiency, distributed generation, and demand response resources, as well as offer 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.

E. Air Pollution Estimates

Air Pollution associated with PG&E's bundled portfolio is forecasted to decrease (nitrogen oxide (NOx)) or stay flat (particulate matter ($PM_{2.5}$)) over the planning horizon due to: (1) changes in PG&E's load and supply portfolio, (2) decreased CHP emissions as units come off contracts, and (3) decreased biogas/biomass emissions. The forecast includes emission estimates from both dispatchable and non-dispatchable resources. These estimates will change as the Commission and load serving entities develop more sophisticated air pollution modeling tools. The forecast could also change as a result of future Commission mandates.

F. Local Air Pollutant Minimization and Disadvantaged Communities

Section 3.E. of this plan describes PG&E's customers located in DACs,[7] PG&E's efforts to minimize local air pollution in these communities, and PG&E's broad set of activities/programs in support of DACs. PG&E is engaged in a comprehensive set of activities to benefit low-income customers and customers in DACs, including low-income support programs such as California Alternative Rates for Energy, Family Electric Rate Assistance, and Energy Savings Assistance, and targeted DAC-focused programs for clean transportation charging infrastructure, energy efficiency, distributed solar, energy storage, demand response, and biomethane. In addition to these programs, PG&E is exploring innovative solutions such as its Oakland Clean Energy Initiative (OCEI), a partnership with local businesses, city government, and East Bay Community Energy to leverage clean energy resources in the Oakland sub-area as a less costly alternative to building a new transmission line through Oakland. This approach will utilize a portfolio of resources that may include: (1) energy efficiency, (2) customer-sited energy storage and other distributed energy resources,

7 PG&E used the CPUC's definition of DACs as set forth in D.18-02-018: "A disadvantaged community should be defined as a community scoring in the top 25 percent statewide and/or in one of the 22 census tracts that score in the highest five percent for pollution burden, according to the most recently available version of the CalEPA CalEnviroScreen Tool."

(3) utility-owned battery storage located at one or two of PG&E's substations, and (4) certain electric-system upgrades. PG&E has also proposed an electrification and fuel switching pilot program in the San Joaquin Valley designed to expand access to affordable and cleaner energy options in these communities.

PG&E also describes the PG&E-owned or -contracted fossil power plants located in DACs. PG&E is not proposing any new gas fired power plants in this IRP and does not currently anticipate a need for future long-term contracts with these facilities in DACs. While PG&E's 2018 IRP provides estimates of PG&E's annual emissions of NOx and $PM_{2.5}$, PG&E does not believe it is appropriate for the state to examine this issue only within the context of the electric sector. Given that 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,[8] PG&E strongly supports a more comprehensive, multi-sector effort to tackle California's air pollution challenges. PG&E supports the new statewide air pollution reduction program based on AB 617 and is also actively considering how to facilitate the growth of electric and low-to-zero emission natural gas and hydrogen vehicles to reduce NOx and $PM_{2.5}$ emissions from the transportation sector. In this inaugural IRP, PG&E presents an estimate of the substantial avoided emissions associated with the nascent but growing clean transportation sector.

Finally, more work needs to be done to develop a standardized framework to evaluate air pollutant emissions and fairly determine responsibility of emissions for resources located in DACs. Facilities owned by or under contract to a given LSE may be dispatched by CAISO to meet the load of a different LSE. Care should be taken to assign responsibility at a local or plant level based on the customers for whom the energy is generated.

G. Diablo Canyon Power Plant

In 2016, PG&E, labor, environmental, and community organizations announced, and sought CPUC approval for, a Joint Proposal to retire the Diablo Canyon Power Plant

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

(DCPP) at the end of its current operating licenses, in 2024 and 2025.[9] In January 2018, the Commission approved the retirement of DCPP.[10]

The RSP analysis in the IRP indicates that, after Unit 1 retires in 2024 and Unit 2 retires in 2025, there are projected to be sufficient GHG-free resources online such that the GHG emissions target for the California electric sector would be met in each year through 2030.[11] This conclusion can be validated during the CPUC's development of the Preferred System Plan (PSP).

PG&E's analyses for the Conforming and Preferred scenarios indicate 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 target for PG&E's bundled electric portfolio would be met in each year through 2030. Under PG&E's Alternative scenario, it is anticipated that PG&E would need to procure approximately 4,800 MW of GHG-free resources to meet RPS and GHG constraints. With the addition of these resources in the timeframe envisioned by the Alternative scenario, PG&E would meet its GHG target in each year through 2030.

H. Lessons Learned

PG&E commends the Commission's development of a flexible IRP process using the CNS methodology to calculate GHG emissions for this inaugural 2017-2018 cycle. Future cycles are expected to evolve to ensure the IRP process can provide the maximum benefit to electric customers and fulfill the vision of SB 350. PG&E offers the following recommendations, discussed in more detail in Section 6, to support the further development of the IRP process:

- **Create GHG Planning Targets that do not Create Disincentives for Transportation Electrification:** PG&E encourages the CPUC to collaborate with the CARB and the California Energy Commission (CEC) to either:
  (1) Adopt a GHG emissions planning target range that allows flexibility for GHG reducing electrification, such as the range proposed by CARB;[12] and/or

---

9 A.16-08-006, filed on August 11, 2016.

10 D.18-01-022.

11 D.18-01-022, Section 4.3 ("Final Analysis Conducted").

12 CARB Staff Report: Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets, issued July 2018 (hyperlink at: https://www.arb.ca.gov/cc/sb350/staffreport_sb350_irp.pdf).

(2) Create a mechanism to credit LSEs' GHG emissions planning target due to electrification-driven GHG reduction in other sectors.[13] PG&E believes that meeting the state's goal of 5 million electric vehicles by 2030 would increase the current 42 MMT electric sector GHG target in the IRP by 1 to 2 MMT. While transportation electrification may require an increase to the GHG target of the electric sector, the increase will be more than offset by the avoided GHG emissions from the transportation sector in the range of 3 to 5 MMT on a lifecycle basis

- **Enhance Inter-Agency Alignment Between the CPUC, California Energy Commission, California Air Resources Board, and the CAISO:** PG&E supports alignment on topics such as GHG target setting, inter-sector GHG crediting, LSE-level accounting and reporting, and efforts to consider economic retirement of gas plants; and
- **Continue Improving IRP Modeling and Process Alignment Activities:** Based on lessons learned in this inaugural IRP, PG&E advocates for improvements in the following areas:
  1. Comprehensive incorporation of DERs into the IRP optimization and the development of a Common Resource Valuation Methodology to align IRP results with other Commission proceedings;
  2. Improvement in RSP development process to incorporate more granular modelling to allow the process to incorporate reliability impact (such as local capacity area needs and solutions); and
  3. Refinement in the methodology for DAC and air pollution requirements to provide the LSE's with consistent and sufficient information to complete the analysis. Additional details are included in the Lessons Learned section.

I. Conclusion

The inaugural IRP cycle represents a crucial moment for electricity planning and GHG reduction in California. Despite the continued fragmentation of retail electric service and the uncertainties facing long-term planning efforts, the Commission has designed a process that includes all LSEs and allows for the flexibility to adapt to future changes in market conditions.

PG&E expects future IRP cycles will further evolve to incorporate demand-side resource options. As the IRP process becomes more integrated, PG&E's modeling

---

13 This mechanism would be necessary to fulfill the requirement of SB 350 that CARB "remove regulatory disincentives preventing retail sellers and local publicly owned electric utilities from facilitating the achievement of greenhouse gas emissions reductions in other sectors through increased investments in transportation electrification." Cal Health & Safety Code § 44258.5(b).

methods and its Preferred portfolio are likely to change and adapt to maximize benefits to its customers. Ultimately, establishing a robust IRP process presents an opportunity for California to continue its visionary leadership to create a clean and reliable energy future while maintaining affordability for all customers.

2. Study Design

This section of the PG&E's Plan addresses the following components of PG&E's analysis:

- Objectives: Presents PG&E's scenarios considered in its IRP analysis and the key objectives that drove its scenario design.
- Scenarios Considered: Description of PG&E's Conforming, Preferred, and Alternative scenarios.
- Methodology:
  - Modeling tool(s)
  - Modeling approach
  - Assumptions

A. Objectives

PG&E's key objectives for its IRP align with the mission that drives all activities at the company: to safely and reliably deliver affordable and clean energy to our customers and communities every single day, while building the energy network of tomorrow. Ensuring the safety of our customers and employees is always PG&E's top priority and will form the core implementation principle as PG&E implements its IRP. 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 2017, PG&E delivered nearly 80 percent of its electricity from GHG-free resources[14] and 33 percent of its electricity from RPS-eligible renewables resources, such as solar, wind, geothermal, biomass, and small hydro.[15] PG&E's IRP analysis focused on meeting the state's aggressive goals for RPS as well as meeting PG&E's LSE GHG planning target.
- **Reliability**: Maintaining system reliability is critical, especially as California transitions towards higher shares of GHG-free generation resources, many of which are intermittent. PG&E's IRP analysis includes PG&E's contribution to

---

14 Note this value uses the California Energy Commission's current Power Content Label methodology. It does not represent a CNS based calculation.

15 PG&E Press Release, issued February 20, 2018 https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20180220_pge_clean_energy_deliveries_already_meet_future_goals.

system and local reliability, in compliance with the CPUC's resource adequacy requirements.[16]

- **Affordability**: PG&E's IRP analysis selects resources to meet the state's clean energy and reliability goals in a least cost manner, and provides a system average rate forecast in compliance with the CPUC's requirements for IOUs.

B. Scenarios Considered

PG&E designed three IRP scenarios to address specific objectives driven by uncertainty in PG&E's future bundled loads and resources. The following section explains the three scenarios considered by PG&E in its 2018 LSE IRP.

All scenarios use the GHG emissions benchmark approach rather than the GHG Planning Price option. The use of the GHG emissions benchmark, along with the adopted "Clean Net Short" GHG accounting methodology, will assist the Commission to ensure that LSE GHG emissions properly represent emissions associated with serving an LSE's load in each hour. It will also enable the Commission to more accurately aggregate the LSE Plans to compare against the RSP GHG emissions.

In Resolution E-4909, PG&E was ordered to hold one or more competitive solicitations to secure energy storage and preferred resources to address reliability issues in three local sub-areas (Feather River Energy Center, Yuba City Energy Center and Metcalf Energy Center). Resolution E-4909 explicitly authorized PG&E to seek to recover the costs of these resources via the Cost Allocation Mechanism (CAM), pursuant to Public Utilities Code section 365.1(c)(2)(A) and (B). To meet the three local sub-area needs, PG&E issued a request for offers (RFO) in February 2018. On June 29, 2018, PG&E submitted an advice letter seeking approval of CAM cost recovery for four energy storage projects (one utility ownership and three power purchase agreements) totaling 568 MW.[17] Because the CPUC has issued a resolution requiring PG&E to secure CAM-eligible resources to meet a local RA need, PG&E has included these resources in its Conforming, Preferred and Alternative scenarios.

---

16 PG&E's bundled portfolio analysis in its LSE IRP used the Commission's assumption in the Reference System Plan that there is no need for new CAISO system reliability resources through the planning horizon. PG&E expects Staff's production simulation modeling to validate this assumption. Additionally, the RSP assumed no economic retirements of gas-fired resources. PG&E expects further economic retirements may drive the need for resource additions for system and/or local reliability resources, similar to the energy storage PG&E has proposed in response to CPUC Resolution E-4909.

17 See, PG&E's Advice 5322-E.

The three IRP scenarios developed by PG&E are summarized in Table 2, below.

TABLE 2
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)	Departed Load Cost Recovery Mechanism
1	Conforming	80,016 GWh	34,187 GWh	6.07 MMT	PCIA with updated market price benchmark[(a)]
2	Preferred	87,291 GWh	33,784 GWh	5.50 MMT	PCIA with updated market price benchmark[(a)]
3	Alternative	87,291 GWh	33,784 GWh	5.50 MMT	GAM/PMM

(a) Market price benchmarks are based on inputs tied to market price forecasts, rather than an administratively determined proxy value for market prices.

1) Conforming Scenario

Objective(s): Meet the filing requirements established by the Commission
Key Variable(s): 2017 IEPR loads utilized per CPUC Filing Requirements

PG&E developed a "Conforming portfolio" based on the California Energy Commission's (CEC) 2017 IEPR load forecast for PG&E with the further modifications for updated CCA loads (King City, Marin Clean Energy (MCE), and CleanPower San Francisco (CPSF)) addressed in the June 18, 2018 ALJ Ruling.[18] The final 2017 IEPR forecast does not reflect the formation of new CCAs in PG&E's territory after 2019 and does not reflect potential expansion of existing CCAs beyond load growth/decline. PG&E's bundled load is 34,187 GWh by 2030 in this scenario.

In the PCIA OIR, the Commission is currently evaluating an alternative methodology to replace the current PCIA cost allocation methodology. While the results of the PCIA OIR are not yet final, PG&E believes that in order to achieve bundled customer indifference, as required by law,[19] the Joint IOUs' GAM/PMM

18 ALJ Ruling Finalizing Load Forecasts and GHG Benchmarks for Individual Integrated Resource Plan Filings, R.16-02-007, June 18, 2018.

19 See, Pub. Util. Code §§ 365.2, 366.2(d), 366.2(a)(4), 366.3.

is the best mechanism to ensure bundled customer indifference. However, if the Commission does not accept the Joint IOUs' GAM/PMM proposal, then it is expected that the current PCIA methodology will be updated by the Commission to ensure cost indifference for bundled customers. Therefore, PG&E has assumed the PCIA market price benchmark methodology is updated to use market-based inputs that are consistent with the forward price curves used in the Conforming scenario. This approach best approximates bundled customer indifference and significantly reduces the costs shift that is inherent in the current PCIA mechanism.

For the Conforming scenario, PG&E' assumptions are consistent with CPUC's RSP assumptions with the following exceptions:

- The 2018 forecast for loads, supply resources and costs is based on D.18-01-009, the Commission-approved 2018 ERRA Forecast revenue requirement, in order to maintain consistency between PG&E's most recently approved ERRA Forecast and its 2018 IRP forecasts;
- Mandated storage in Resolution E-4909 is included in PG&E's bundled portfolio to ensure accurate accounting of all resources in all scenarios because the application to approve these CAM resources was made after the release of the CPUC's RSP; and,
- For future procurement for mandated programs not yet in PG&E's bundled electric portfolio, PG&E used its internal cost estimates derived from PG&E's commercial data for calculating the revenue requirement.

2) Preferred Scenario

Objective(s): Consider PG&E's resource plan under its internal load forecast
Key Variable(s):

- PG&E's internal load forecast, which includes key assumptions about PG&E loads, load modifiers (electric vehicles, distributed generation, energy efficiency, etc.), and CCA growth; and
- CAISO system electric vehicle levels

The Preferred scenario considers how PG&E's resource plan would change using PG&E's internal load forecast.

In the Preferred scenario, PG&E's bundled load is 33,784 GWh by 2030 (approximately 39 percent of PG&E service territory load). While the 2030 bundled loads in PG&E's Conforming and Preferred scenarios are similar (in the Conforming scenario PG&E bundled load is approximately 400 GWh (1.2 percent) higher than the Preferred scenario), the underlying drivers of the forecasts are significantly different. PG&E's internal forecast used in the Preferred scenario assumes higher PG&E system loads driven by electric vehicles and lower output from distributed generation, which is then offset by additional CCA departures.

PG&E's internal load forecast differs in key ways from the CEC's 2017 IEPR forecast used in the development of the Conforming scenario. PG&E's internal load forecast, as reflected in the Preferred scenario, increases the 2030 CCA load shift in PG&E's territory by 7,148 GWh above the departure level reflected in the Conforming scenario.[20] The largest driver for this increase is the inclusion of CAA load departure in 2030 related to CCAs that do not yet exist today. The Conforming scenario does not recognize this possibility. PG&E believes this is a reasonable assumption given that the Commission is considering a future in which 85 percent of retail load may be served by non-IOU providers.[21]

The Preferred scenario also includes different values for PG&E service territory load and load modifiers. In addition to alternate values for energy efficiency (EE) and distributed generation (DG) as compared to the IEPR forecast, PG&E's internal load forecast assumes two million electric vehicles in PG&E service territory, consistent with five million zero-emission vehicles statewide by 2030 per the goal set by the Governor in Executive Order B-48-18 (compared to the 3.3 million electric vehicles assumed statewide in the 2017 IEPR).[22] This reflects PG&E's forecast of future electric vehicle growth that can be achieved through a combination of innovative customer programs, rate design, and infrastructure development.

PG&E adjusted the GHG emissions benchmark for this scenario[23] to reflect changes in both PG&E net system sales and PG&E bundled sales. PG&E's share of the 2030 GHG emissions target for the PG&E system decreased from 42.7 percent

20 With the CCA load forecast updates filed by King City, MCE, and CPSF, the CCA load in 2030 under the Conforming scenario is 36,308 GWh. CCA load in the Preferred scenario assumes 43,456 GWh, or 7,148 GWh more than under the Conforming scenario.

21 CPUC, Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework, Staff White Paper, May 2017, p. 3.

22 Office of Governor Edmund G. Brown Jr. Press Release issued January 25, 2018, https://www.gov.ca.gov/2018/01/25/governor-brown-delivers-2018-state-of-the-state-address-california-is-setting-the-pace-for-america/.

23 The same adjustment was made for the 2030 PG&E emissions benchmark for the Alternative scenario, since the same system and bundled load assumptions are used.

to 38.7 percent.[24] Applying the lower share percentage to the 2030 PG&E electric service territory system target of 14.21 MMT yields a lower 2030 GHG emissions benchmark of 5.50 MMT. If the Commission adopts PG&E's Preferred scenario, the 2030 GHG emissions benchmark for the other LSEs located in the PG&E system would need to be adjusted accordingly to reflect their adjusted share of the system load.

In the Preferred scenario, PG&E has used the same PCIA calculation methodology as the Conforming scenario, whereby the market price benchmark methodology is updated to use market-based inputs that are consistent with the forward price curves used in the Preferred scenario. Using this approach best approximates bundled customer indifference and significantly reduces the costs shift inherent in the current PCIA mechanism.

3) Alternative Scenario

Objective(s): Consider PG&E's resource needs under the Joint IOUs' GAM/PMM proposal
Key Variables:

- Key variables listed in the Preferred scenario;
- Allocation of RECs and RA from PG&E's RPS and Large Hydroelectric resources under GAM; and,
- Sales of RA capacity under PMM from PG&E's fossil and nuclear generation.

The Conforming and Preferred scenarios forecast PG&E maintaining its significant GHG-free resource portfolio while its bundled loads generally decline. This limits PG&E's need for any new resource investment to meet its RPS compliance target and its GHG emissions benchmark.

The Alternative scenario assumes the Commission fully adopts and implements the Joint IOUs' GAM/PMM proposal as presented in the PCIA OIR testimony.[25] The GAM/PMM proposal allocates existing IOU RPS commitments to all LSEs on a load-share basis, ensuring that all customers continue to benefit from the IOUs'

24 The 38.7 percent share of system target is calculated by dividing PG&E bundled sales (33,784 GWh) by PG&E net system sales (87,291 GWh).

25 See, Joint IOUs' Prepared Testimony, dated April 2, 2018, in R.17-06-026 (hyperlink at: https://www.rtoinsider.com/wp-content/uploads/PGE-CCA-filing.pdf).

RPS commitments and pay their equitable share of such resources.[26] The Alternative scenario also reflects the reduction of RA capacity through the auction mechanism of PMM.

The Alternative scenario uses PG&E's internal load forecast described in the Preferred scenario above, which assumes continued load growth for CCAs in PG&E's service territory. The Alternative scenario assumes significant allocation of RECs and RA attributes to LSEs serving departed load, which dramatically changes PG&E's resource plan and near-term procurement needs.[27]

The sections that follow describe PG&E's modeling approach to determine its portfolio within these three scenarios.

C. Methodology

1) 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., hourly energy prices) are used as inputs into the bundled portfolio assessment. A high-level description of the modeling tools used in the analysis follows below.

26 Allocated attributes include RECs and RA. Departed load's share of GHG-free attributes for GAM resources (RPS-eligible resources and large hydro, including Helms) are not counted as GHG-free resources in PG&E's CNS calculation. However, because it is unclear whether DCPP's GHG-free attribute would be purchased by entities outside of the CAISO market, PG&E is counting DCPP's GHG-free attribute as part of its bundled portfolio. If the Commission were to adopt the Joint IOUs' GAM/PMM proposal, PG&E would seek to monetize these attributes so they could be counted by other LSEs.

27 In the IRP modeling, PG&E does not use the GHG-free attribute of allocated RPS and large hydro resources.

CAISO System Tools

1) ***CPUC's RESOLVE Model***: PG&E is using RESOLVE to model capacity expansion at the CAISO level. Using RESOLVE helps ensure consistency across all scenarios and easy comparisons between the Conforming scenario and PG&E's Preferred and Alternative scenarios. However, because the commitment and dispatch modeling and the time granularity in RESOLVE is highly simplified, PG&E has relied solely on the capacity expansion results (i.e., modeled system-level resource portfolios under different load assumptions). PG&E has used its own proprietary models 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:***[28] This statistical model estimates CAISO hourly power prices as a function of the CAISO system net-load. Key inputs for this model are the CAISO system-level resource mix forecast (which comes from a specified RESOLVE model run), CAISO load, natural gas prices, GHG prices and net import levels. The hourly prices are used to calculate the bundled portfolio generation revenue requirement. Additionally, the hourly prices inform the selection of new resources to be added to the bundled portfolio in the Alternative scenario in which new resources are needed to meet RPS targets and the GHG planning target. Finally, the hourly prices are 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***: This tool uses option theory to impute 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.
4) ***PG&E's REC Price Forecast Tool***: 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.

Bundled Portfolio Analysis Tools

1) ***CPUC's Clean Net Short Calculator:*** The CNS Calculator developed by Energy and Environmental Economics (E3) is used to quantify PG&E's GHG emissions

28 Note that this model 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.

associated with serving its bundled load on an hourly basis for each of PG&E's IRP scenarios.

2) ***PG&E's Portfolio Planning Program (P3):*** This proprietary model developed by PG&E forecasts PG&E's bundled portfolio generation and procurement costs.[29] The P3 program 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 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. (See Appendix 1 for a more detailed description).

2) Bundled Portfolio Modeling Approach

a) Overview

PG&E's 2018 IRP modeling effort is guided by a set of modeling principles:

- Adhere to CPUC IRP guidelines;
- Provide planning insights to meet study objectives; and
- Allow meaningful comparison between scenarios.

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

PG&E utilized a three-step process described in this section to develop an optimized bundled portfolio for each of the three scenarios considered by PG&E. This process allows PG&E's portfolios to be tested against the following requirements: the GHG emission planning target established by CPUC, the state's

29 PG&E has used the P3 model in a variety of regulatory proceedings including ERRA and IEPR forecasts.

Renewable Portfolio Standard targets, and PG&E's system and local capacity[30] needs to meet Resource Adequacy requirements.[31]

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.

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[32] will meet the three portfolio requirements and determine PG&E's incremental resource need.

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

If Step 2 above shows a need for additional resources – for instance, to meet the GHG planning target – then an additional step is taken to determine the optimal portfolio to fulfill such needs. 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 for PG&E's bundled customers.

---

30 As required by the IRP, PG&E assessed its ability to meet local capacity requirements in 2018 and 2012.

31 PG&E's bundled portfolio analysis in its LSE IRP used the Commission's assumption in the RSP that there is no need for new CAISO system reliability resources through the planning horizon. PG&E expects Staff's production simulation modeling will validate this assumption. Additionally, the RSP assumed no economic retirements of gas-fired resources. PG&E expects further economic retirements may drive the need for resource additions for system and/or local reliability resources, similar to the energy storage PG&E has proposed in response to CPUC Resolution E-4909.

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

b) Details

This section includes a more detailed description of the modeling processes underlying the three-step approach described above and the key differences between the Conforming scenario and other scenarios included in this filing. This section 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 scenario, PG&E used the CPUC's prescribed load forecast for PG&E bundled customers. For PG&E's Preferred and Alternative scenarios, PG&E used its own bundled load forecast. A summary of the differences between the two forecasts is provided in the Assumptions section below.

b) *Establish Price Inputs* – Price inputs are used for developing hourly energy, REC, and RA prices, and incremental resource portfolio selection for the Alternative scenario. For the Conforming scenario, PG&E aligned price assumptions with RSP assumptions or assumptions from CEC 2017 IEPR. For the Preferred and Alternative scenarios PG&E used its internally-developed price assumptions. A summary of the different price inputs is provided in the Assumptions section below.
   1. Natural Gas and GHG Allowances – To develop the hourly energy prices for the Conforming scenario, PG&E used the 2017 IEPR GHG price forecasts. For the Preferred and Alternative scenarios, PG&E's used its own price forecasts.
   2. Technology Cost – For developing REC prices, PG&E used levelized cost of energy (LCOE) forecasts for different technologies from the CPUC's RSP RESOLVE model for the Conforming scenario, and PG&E's LCOE forecasts for the Preferred and Alternative scenarios. PG&E also used its LCOE forecast for developing an incremental resource portfolio to meet the identified need in the Alternative scenario.

c) *Develop CAISO System Portfolio* – For the Conforming scenario, this is simply the CPUC's RSP. For the Preferred and Alternative scenarios, PG&E developed an alternative load forecast that included 5 million EVs statewide by 2030, and then used the RESOLVE modeling tool to create a corresponding alternative CAISO system.[33] PG&E assumed a change related to an increase

[33] See Assumptions section for additional details.

in EVs and, as described in the Scenarios section above, all other system requirements and assumptions in the Preferred and Alternative scenarios are maintained from the RSP scenario (e.g., 42 MMT by 2030 GHG emissions planning target, retirement assumptions, etc.) to create the alternative CAISO portfolio.

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.[34] These hourly energy prices are integral to calculating the bundled portfolio generation revenue requirement for energy market sales or purchases. They are also 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 all three scenarios, the CAISO systems produced by RESOLVE had sufficient capacity margins across the planning horizon. As a result, PG&E calculated capacity price 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 Renewable Energy Credit (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 for the forecasted REC prices.

   For the Conforming scenario, REC prices were derived using the technology costs from RESOLVE and Conforming scenario prices. For the Preferred and

34 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).

Alternative scenarios, REC prices were derived using PG&E's technology cost forecasts and Preferred/Alternative scenario price curve. The scenario-specific REC prices are provided in Section 3 (Study Results) and in Appendix 3.

Step 2. Determine Incremental LSE Resource Needs

For the Conforming and Preferred scenarios, in order to determine PG&E's additional resource need, PG&E modeled its bundled supply portfolio based on its latest data on existing contracts, future procurement for existing mandated programs, and planned resource retirements.

For the Alternative scenario, PG&E adjusted its bundled portfolio resource forecast using the Joint IOUs' GAM/PMM proposal as proposed in the PCIA OIR testimony. Specifically, resource attributes are allocated on a vintaged basis as follows:

- RECs are allocated under GAM for RPS-eligible resources,
- RA is allocated under GAM for RPS-eligible resources and large hydro,
- GHG-free attributes (for CNS counting) are allocated for RPS-eligible resources and large hydro (including Helms),
- GHG-free attributes (for CNS counting) are not allocated for nuclear,[35] and
- RA for non-GAM resources is auctioned via PMM.

For all scenarios, PG&E included energy storage resources for which it has sought approval pursuant to Resolution E-4909.

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

a) *GHG Emissions:* For each scenario, PG&E's GHG emissions and need for incremental resources was calculated using the CPUC approved CNS Calculator with the following adjustments.
   1. Alignment of Resource Generation in CNS Calculator with PG&E's Forecasted Generation (all scenarios) – The CNS Calculator uses inputted resource capacity and corresponding 8,760-hour resource profiles to develop annual resource generation. PG&E observed that the CNS Calculator overstated GHG-free resource generation relative to PG&E's internal forecast. So as to not underestimate its GHG emissions, PG&E adjusted the resource capacity inputs such that the resulting GHG-free generation from the CNS Calculator matched PG&E's internal generation

35 See Footnote 26.

forecast. PG&E suggests that the Commission validate other LSEs' results to ensure GHG-free generation is not overstated.

2. Bundled RPS Energy Sales (Conforming and Preferred scenarios) – PG&E has forecasted additional renewable energy sales through 2030 and has decreased its GHG-free generation used to serve its portfolio load by the amount of these sales.[36] The sales are shown in Tables 12 and 17, and Appendix 3.
3. Bundled load – In the Conforming scenario, PG&E uses the prescribed 2017 IEPR 2030 retail sales, adjusted by the ALJ in this proceeding.[37] In the Preferred and Alternative scenarios, PG&E assumes 2030 retail sales that align with its internal load forecast. This resulted in a lower GHG planning target for PG&E.
4. Portfolio DER Amounts – In the Conforming scenario, PG&E used the default methodology in the CNS Calculator to determine DER levels for its portfolio as a percentage of CAISO DERs based on its ratio of bundled retail sales to CAISO retail sales. In the Preferred and Alternative scenarios, PG&E used the customized demand inputs in the CNS Calculator to include levels of DERs that align with its internal bundled load forecast.

b) *RPS Requirement:* For each scenario, PG&E's bundled supply portfolio was tested to identify if additional renewables are needed to meet RPS compliance requirements.

c) *Resource Adequacy Requirement:* For each scenario, PG&E's bundled supply portfolio was tested to identify if additional resources are needed to meet PG&E's share of system RA requirements.

<u>Step 3. If Necessary, Acquire Least-Cost New Resources</u>

A bundled portfolio optimization step is triggered if Step 2 identifies a need for additional resources to meet the GHG planning target or RPS requirements. PG&E uses its Bundled Portfolio Optimization Tool (BPOT) to select a set of least-cost resources to meet its RPS, GHG, and RA planning requirements. A detailed description of the BPOT is provided in Appendix 1.

36 The approximately 2,000 GWh/yr of RPS sales is strictly a planning assumption and does not represent sales volumes PG&E will actually execute. Execution volumes are dependent on a combination of factors, including: limits under PG&E's pre-approved RPS sales framework, market demand, market pricing, etc.

37 ALJ Ruling Finalizing Load Forecasts and GHG Benchmarks for Individual Integrated Resource Plan Filings, R.16-02-007, June 18, 2018.

Of the three scenarios studied, only the Alternative scenario resulted in the need for new resource acquisition. See Section 3 (Study Results) for additional information on how that need is addressed. Any incremental RA need not met by the incremental resource additions is met through RA market procurement.

3) Revenue Requirement and Rates Modeling

PG&E developed its revenue requirement and System Average Bundled Rates (SABR) for the Conforming and Preferred scenarios utilizing the 2017 IEPR as the baseline, consistent with the guidance provided in D.18-02-018 and the June 18, 2018 ALJ Ruling.[38] Only generation varied by scenario. The baseline forecast includes the following components:

- Distribution (D)
- Transmission (T)
- Demand-side Management (DSM) Programs
- Generation (G)
- Other[39]

The distribution revenue requirement relies on the 2017 IERP data and reflects PG&E's 2017 GRC base revenues for years 2018 and 2019. In 2020, a 2.2 percent escalation factor is applied to the 2019 base revenue requirement. Subsequent years escalate the prior year's base revenue requirement using a 3.4 percent escalation factor, consistent with the escalation factors assumed as of the 2017 IEPR. 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) (2019-2021), Self-Generation Incentive Program (2019), Alternative-Fuel Vehicle, Customer Energy Efficiency Shareholder Incentive, Catastrophic Event Memorandum Account, CPUC Fee, Family Electric Rate Assistance, Mobile Home Park investments, Hazardous Substance Mechanism, and the Lawrence Livermore National Laboratory (2019).

The transmission revenue requirement includes the Transmission Owner base revenue requirement for 2018 as of the 2017 IEPR. In addition, the adjustments for the FERC-jurisdictional balancing accounts are also included in the transmission revenue requirement: (1) Reliability Services Balancing Account

38 ALJ Ruling Finalizing Load Forecasts and GHG Benchmarks for Individual Integrated Resource Plan Filings, R.16-02-007, June 18, 2018.

39 In this IRP, PG&E is including the three generation-related non-bypassable charges in the Other category, which in the 2017 IEPR included other existing non-bypassable charges such as the Public Purpose Program (PPP) charge, the DWR Bond Charge and the Nuclear Decommissioning Charge.

(RSBA), (2) Transmission Revenue Balancing Account (TRBA), and (3) Transmission Access Charge Balancing Account (TACBA).

The DSM Programs' revenue requirements include Demand Response, Energy Efficiency, and Demand-Side Management Programs.

The revenue requirements included in the Other category are: (1) the Public Purpose Programs, excluding those considered Energy Efficiency, Demand Response, or Demand-side Management, (2) DWR Bond (which expires in 2020), (3) Nuclear Decommissioning, (4) Ongoing Competitive Transition Charge (CTC), (5) New System Generation Charge (NSGC), and (5) the Tree Mortality non-bypassable charge (TMNBC).

The baseline 2017 IEPR forecast is then paired with the scenario's load forecast, GHG allowance prices, and updated generation-related non-bypassable charges (Cost Allocation Mechanism (CAM), Ongoing CTC, and TMNBC) to derive the System Average Delivery Rate (SADR). 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 scenario, PG&E relied on the Commission's planning assumptions to develop price assumptions used for market purchases or sales. For PG&E's Preferred scenario, PG&E relied on the Commission's RSP (rerun to include the 5 million EVs modeled statewide), but utilized its own internal forecasts for commodity prices to better reflect PG&E's view of the future (natural gas prices, GHG allowance costs, and REC and RA market prices). The Conforming and Preferred 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 forecast generation revenue requirement net of the PCIA revenues was divided by PG&E bundled sales to determine bundled customers' Generation Rate. The SADR and the Generation rate are summed to determine the SABR. The SABR is also presented net of the forecasted GHG revenue return, which reflects the twice-yearly climate credits provided to customers.

4) Air Pollution Forecast

This section provides an overview of PG&E's methodology for calculating the emissions of two air pollutants associated with serving PG&E's bundled load: NOx and $PM_{2.5}$[40] for both dispatchable and non-dispatchable resources.

Dispatchable Resources – Since the Commission did not propose a methodology to forecast air pollutants, PG&E proposes using the CNS methodology to align 2030 criteria pollutant emissions calculations with the current GHG accounting methodology utilized for GHG emissions.[41] PG&E believes that absent additional guidance from the Commission, this methodology presents a coherent systemwide method to estimate, in a consistent manner, multiple emission types (GHG, NOx, $PM_{2.5}$) that result from an LSE's hourly use of fossil generation to serve its load.

For Dispatchable resources, plant start-ups could have a significant impact on NOx emissions. Therefore, to capture emissions during start-ups, PG&E included NOx emissions from combined cycle gas turbine (CCGT1/CCGT2) starts. The startup emissions rate[42] was calculated using historical emissions data from PG&E-owned CCGTs. PG&E did not estimate NOx start emissions from combustion turbines (peakers) since PG&E did not have similar access to historical generation and emissions data for this type of resource. Since CCGTs starts account for over 90 percent of the 2030 starts in the RESOLVE modeling,[43] capturing the startup emissions from CCGTs should be a reasonable approximation for start emissions. PG&E did not estimate emissions from reciprocating engine starts since these types of units are assumed to start quickly.

---

40 $PM_{2.5}$ refers to particulate matter with a size equal to or less than 2.5 microns.

41 To develop 12x24 generation emissions factors, PG&E used the NOx and PM2.5 emissions rates for dispatchable fossil units provided by the CPUC, coupled with annual generation and fuel burn data from the RSP RESOLVE run. PG&E then converted these annual emissions amounts into 12x24 emissions factors that aligned with the 12x24 CNS GHG emissions factors (i.e., a higher hourly CNS position correlates to both an increased GHG as well as NOx/PM emission intensity). This method is congruent with the way 12x24 GHG emissions factors for the reference system plan were calculated, and can be easily folded into the CPUC's CNS Calculator.

42 PG&E notes that start-up NOx emissions could vary significantly based on generator configuration, manufacturer, and start type (cold/hot). Furthermore, an average emissions rate for starts may not reflect start-up emissions for all CCGT units.

43 Not including starts from reciprocating engines.

Non-Dispatchable Resources – For non-dispatchable resources, estimated emissions are based on PG&E's forecasted generation from combined heat and Power (CHP), Biomass, and Biogas resources[44] using emissions factors summarized in Table 3.

Emission Factor Assumptions – Table 3 summarizes the emissions factors used to develop NOx and $PM_{2.5}$ emissions. PG&E used emissions factors from the CPUC's fall 2017 DAC analysis[45] and supplemented missing assumptions using its own historical plant emissions, the EPA's historic plant emissions data from the Emissions and Generation Resource Integrated Database (eGRID),[46] and other emissions information from the EPA,[47] to develop a complete set of emissions factors for use in this analysis.

44 While biomass and biomethane resources meeting Bucket 1 RPS eligibility rules are deemed GHG-free, consistent with CARB's cap-and-trade regulation and U.S EPA policy regarding biogenic CO_2 emissions, these facilities do emit criteria pollutants. As a result, PG&E has included estimates of NOx and $PM_{2.5}$ from biomass and biogas resources in its portfolio.

45 For dispatchable fossil units (CCGT1, CCGT2, Peaker1, Peaker2, and Reciprocating Engines, PG&E used both the NOx and $PM_{2.5}$ emissions factors provided by the CPUC in its September 19, 2017 RESOLVE Post-Processing Air Pollution and DAC analysis. The DAC analysis did not include PM2.5 emissions factors for non-dispatchable CHP and biogas units, so PG&E used CCGT $PM_{2.5}$ emissions factors from the DAC analysis for these types, since they are generally similar.

46 PG&E used 2016 historical emissions and operation data from the EPA's eGRID database in estimating NOx emissions of its non-dispatchable CHP, biogas, and biomass resources (hyperlink at: https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid).

47 PG&E used an EPA-supplied $PM_{2.5}$ emission factor for its non-dispatchable biomass units. The 0.065 lb/MMBtu biomass emissions factor from the EPA's Table 1.6-1 is for a resource with some form of pollution control. PG&E notes the emissions factor for biomass can be above or below this quantity based on the level of plant pollution control (hyperlink at: https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s06.pdf).

TABLE 3
DATA USED TO DEVELOP AIR POLLUTION ESTIMATES

Line No.	Resource Type	NOX Emissions Factor (lb/MWh)	NOx Emissions Factor Source	PM2.5 Emissions Factor (lb/MMBtu)	PM2.5 Emissions Factor Source
1	CAISO_CCGT1	0.07	CPUC DAC Analysis	0.0066	CPUC DAC Analysis
2	CAISO_CCGT2	0.07	CPUC DAC Analysis	0.0066	CPUC DAC Analysis
3	CAISO_Peaker1	0.099	CPUC DAC Analysis	0.0066	CPUC DAC Analysis
4	CAISO_Peaker2	0.279	CPUC DAC Analysis	0.0066	CPUC DAC Analysis
5	CAISO_Reciprocating_Engine	0.5	CPUC DAC Analysis	0.01	CPUC DAC Analysis
6	CHP	Historical emissions for existing resources; avg rate for future resources	EPA's eGrid 2016 (PG&E Contracted Units)	0.0066	Assumed to be the same as CCGT emission factors
7	Biogas	Historical emissions for existing resources; avg rate for future resources	EPA's eGrid 2016 (PG&E Contracted Units)	0.0066	Assumed to be the same as CCGT emission factors
8	Biomass	Historical emissions for existing resources; avg rate for future resources	EPA's eGrid 2016 (PG&E Contracted Units)	0.065(a)	EPA Biomass emission factor (with some pollution control)
9	CCGT Startup emissions	80 lb NOx/start (for CCGT1/CCGT2 units only)	Derived from historical startup emissions	NA(b)	

____

(a) Pollution control technology can significantly impact the $PM_{2.5}$ emissions from Biomass resources. Per EPA's report (Page 6 https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s06.pdf), depending on the pollution control technology, PM2.5 emission factor could range from 0.035 to 0.43 lb/MMBtu. For this analysis PG&E assumes resources have some level of emissions control to limit the emissions to 0.065lb/mmbtu.

(b) $PM_{2.5}$ emissions are a function of fuel burn (emission factor is specified in lb/MMBtu). Estimating the amount of fuel consumption is sufficient to calculate total $PM_{2.5}$ emissions.

The CNS methodology used by PG&E is suitable to calculate LSE emissions at a system level. This methodology presents a coherent method to estimate system emissions for multiple emission types (GHG, NOx, $PM_{2.5}$) that result from an PG&E's hourly use of fossil generation to serve its load. However, for reasons discussed in Section 3 (Study Results), PG&E was unable to determine levels of air pollutants in DACs attributable to serving its bundled load.[48] PG&E encourages the Commission to work with stakeholders to develop for the next IRP a standardized framework that can be used by all LSEs to evaluate air pollutant emissions.

5) Assumptions

This section provides a discussion of input assumptions that are relevant for this IRP filing and are materially different across the study scenarios. Other assumptions that do not differ by scenarios (i.e., identical to the Conforming scenario or otherwise have *de minimis* impact on results) are not discussed here.

PG&E's analysis utilizes the standard planning assumptions required by the Commission, including the 2017 IEPR load and load modifier forecasts and the natural gas prices, for its Conforming scenario. Where the Commission did not provide guidance, PG&E utilized its internal view for other key assumptions in its Preferred and Alternative scenarios.

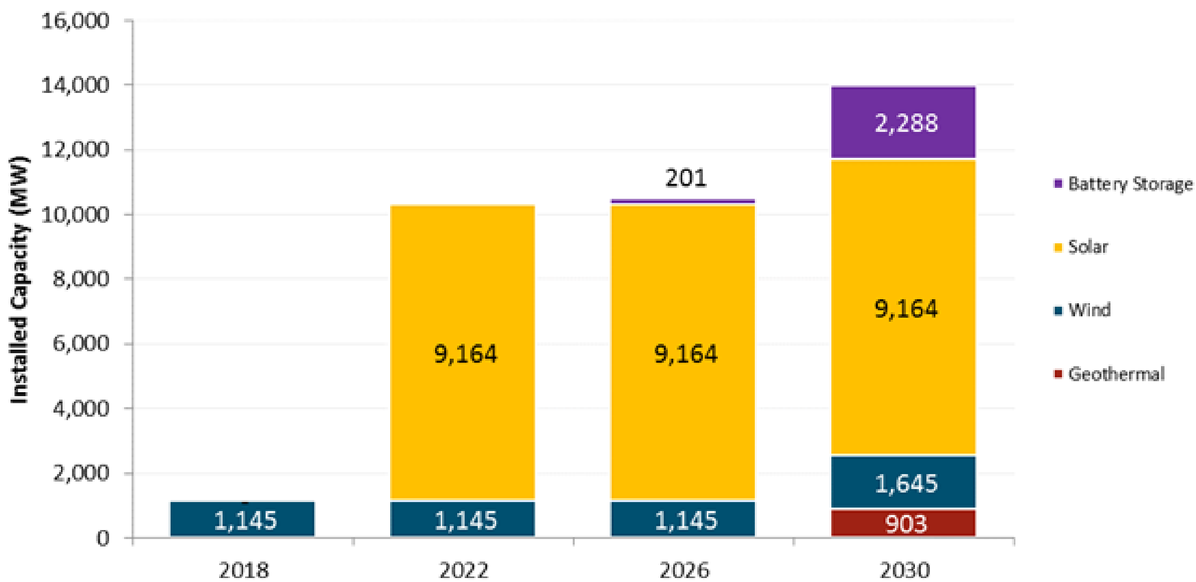
a) CAISO System Load and Supply Forecast

For the Preferred and Alternative scenarios, PG&E updated the RSP RESOLVE model by increasing the CAISO system level EV forecast to meet 5 million vehicles statewide by 2030 to create a corresponding CAISO system resource portfolio. All other system requirements and assumptions are maintained from the RSP scenario (e.g., 42 MMT by 2030 GHG emissions planning target, retirement assumptions). PG&E does not endorse all of the CPUC's other assumptions in the RSP and expects further refinement will occur in future IRP cycles. The CAISO supply forecast was developed using the outputs of this RESOLVE run.

Figure 2 shows the incremental CAISO system resources reflecting the additional electric vehicles in PG&E's Preferred and Alternative scenarios.

48 As noted in Section 3.E, PG&E is not able to forecast air pollution levels in DACs attributable to serving its bundled load due to the fragmentation of LSEs in its service territory and other factors.

FIGURE 2
INCREMENTAL CAISO SYSTEM RESOURCES FOR PG&E'S PREFERRED AND ALTERNATIVE SCENARIOS



b) PG&E Bundled Load Forecast

Table 4 below summarizes the key differences between the 2017 IEPR, the Conforming scenario load forecast, and PG&E's internal load forecast. From a PG&E service territory perspective, PG&E's internal load forecast assumes significantly higher levels of electric vehicles by 2030, meeting PG&E's goal of 2 million electric vehicles in its service territory by 2030. It also assumes lower output from distributed generation, higher levels of energy efficiency, and other minor adjustments. From a bundled load perspective, PG&E's internal forecast assumes significantly more CCA load growth than the 2017 IEPR. The difference in load for existing CCAs was mostly closed by the Conforming portfolio CCA load updates by King City, MCE, and CPSF. However, neither the 2017 IEPR nor the Conforming scenario loads assume any new CCAs form, while PG&E's internal forecast assumes continued growth in new CCA loads.

PG&E utilized its internal forecast in developing its Preferred and Alternative scenarios. PG&E believes its internal forecast better estimates its bundled customer portfolio based on the use of more realistic market and policy assumptions, and more recent and granular technology-specific inputs.

Specifically, PG&E's forecast better reflects the impact of the following key drivers on bundled customer load:

1. **Continued Expansion of Community Choice Aggregation:** PG&E's forecast reflects continued formation and expansion of CCAs. The CCA market is large, dynamic and rapidly expanding, yet the Conforming scenario forecast reflects no expansion of existing CCAs or formation of new CCAs beyond 2019. As a result, the Conforming case projects 20 percent less load served by CCAs in 2030 than PG&E's forecast.
2. **Attainment of Electric Vehicle Policy Targets:** PG&E's forecast for EVs aligns with the target of five million zero-emission vehicles in California by 2030 as established by the Governor's January 2018 Executive Order.[49] The Conforming scenario reflects 3.3 million light duty EVs statewide in 2030.
3. **Attainment of Energy Efficiency Goals:** PG&E's internal forecast reflects the adoption of additional policy measures necessary to achieve the doubling of cost-effective EE, as required by SB 350. The Conforming scenario, in contrast, does not account for policy changes outside of the normal EE policy progressions.
4. **More Realistic Solar PV Generation:** PG&E applies more recent (2017) and more granular solar PV generation profiles that were calibrated with empirical data from the CSI. This updated generation profile results in a [redacted] percent lower estimate of energy produced from rooftop solar PV when compared to the CEC's profile. The Conforming scenario appears to use PV system performance numbers from a 2012 impact evaluation report, which are likely outdated.[50]
5. **More Recent Load and Economic Data:** PG&E performs a full sales forecast update at least once a year to take advantage of the most recent data available. For example, the forecast utilized in the Preferred scenario relies on customer billings and sales data through December 2017, as well as a long-term economic outlook specific to PG&E's service territory prepared by Moody's Analytics in December 2017. The Conforming scenario, in contrast, is based on load and economic data through 2016. This distinction is important as the energy landscape is changing quickly.

---

49 Executive Order B-48-18.

50 CEC 2018-2030 Revised Forecast p.A-2, Footnote 97 and p. A-7 Footnote 105 state: "Energy and Environmental Economics, Inc. November 2013. California Solar Initiative 2012 Impact Evaluation. Report is forthcoming but staff was provided a copy of the draft report and the simulated PV production data."

In short, PG&E's internal forecast utilizes the most up-to-date data on sales, weather, economics, and solar PV penetration, and reflects likely policy drivers. Thus, PG&E believes its internal forecast constitutes the best available estimate of the impact of load and load modifiers for long-term bundled sales.

TABLE 4
RECONCILIATION OF PG&E LOAD FORECASTS IN 2030[a]
(GWH)

Line No.		CEC 2017 IEPR	Modifications approved by CPUC	Conforming Scenario Loads	Adjustments for Internal Load Forecast	PG&E Internal Load Forecast (Preferred and Alternate Scenarios)
1	PG&E Gross System Usage	116,897		116,897	[redacted]	
2	Less: Energy Efficiency[b]	(22,573)		(22,573)		
3	Less: DG	(20,290)		(20,290)		
4	*Solar PV*	(16,459)		(16,459)		
5	*Non-PV DG[c]*	(3,831)		(3,831)		
6	Plus: EV[d][e]	5,982		5,982		
7	PG&E Net System Sales	80,016		80,016	7,275	87,291
8	Less: DA & CCA					
9	*DA[f]*	(9,520)		(9,520)	(531)	(10,051)
10	*Existing CCAs*	(31,176)	(5,132)	(36,308)	(773)	(37,081)
11	*Prospective CCAs*	–	–	–	(6,375)	(6,375)
12		(40,696)	(5,132)	(45,828)	(7,679)	(53,507)
13	PG&E Bundled Sales	39,320	(5,132)	34,187	(403)	33,784

(a) All numbers on this table are at the customer meter.

(b) Energy Efficiency includes committed savings from utility programs and Codes & Standards as well as Additional Achievable Energy Efficiency (AAEE) beginning in 2018.

(c) Non-PV DG is incremental to 2001.

(d) CEC EV total includes sales to Medium and Heavy Duty vehicles. PG&E includes only Light-Duty Vehicles.

(e) CEC Electrification refers to additional transportation sector electrification from ports, airports, truck stops and other cargo handling. PG&E Electrification refers to additional building electrification from appliance retrofits and ZNE policy mandates.

(f) Direct Access includes sales to BART. PG&E's Preferred Case DA forecast is based on January 2018 DA Activity reports submitted to the CPUC, and PG&E's BART forecast incorporates recent and projected service expansions to the Warm Springs/Milpitas/North San Jose area.

Descriptions of Load Modifier and CCA/DA Differences

Additional Achievable Energy Efficiency (AAEE)

For its Preferred and Alternative scenarios, PG&E used its internal forecast for AAEE. Relative to the Conforming scenario forecast, PG&E's forecast assumes California policy makers will advance more robust measures (e.g., new codes, standards and programs) in attempt to attain the SB 350 goal of doubling cost-effective energy efficiency by 2030. The Conforming scenario represents an AAEE forecast that is based on a continuation of existing policies and standard policy progression. It does not account for more aggressive policy changes likely required to meet the SB350 goals.

The CEC adopts the CPUC/Navigant Potential & Goals (P&G) Study as the mid-AAEE case.[51] PG&E generates a probabilistic analysis of key drivers to the P&G mid-AAEE deterministic forecast, which enables PG&E to include new information not available when the mid-AAEE was developed and to integrate internal subject matter expert opinion on the likelihood of different policy scenarios.

Since the CEC and PG&E use different modeling methods and inputs to develop their forecast, a direct attribution of the differences in AAEE forecasts to particular methods, assumptions and inputs is not possible. However, the differences can generally be attributed to the fact that, in applying its probabilistic analysis to the P&G deterministic mid-AAEE forecast, PG&E reflects an expectation of more ambitious policy action to achieve SB 350 goal of doubling cost-effective energy efficiency.

Solar PV Distributed Generation

For its Preferred and Alternative scenarios, PG&E used its internal forecast for solar PV distributed generation. Relative to the Conforming scenario forecast, PG&E's forecast reflects more accurate and recently updated solar PV generation profiles and different assumptions about the phase-in of Title 24 requirements for solar PV. These differences result in PG&E's solar PV GWh forecast being [redacted] percent lower than the Conforming scenario in 2030.

51 CPUC/Navigant, "Energy Efficiency Potential & Goals Study for 2018 and Beyond", September 25, 2017 (hyperlink at: ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/DAWG/2018_Potential%20and%20Goals%20Study%20Final%20Report_092517.pdf).

PG&E's forecast of adopted PV capacity is generated by three modules: mass market retrofit, new construction (Title 24), and incentive programs. Like the CEC, PG&E's mass market retrofit model uses a Bass diffusion framework. PG&E adopts the mean of its probabilistic forecast using high, mid and low values for the key independent variables of market size, tariff, and solar PV system pricing. Again, similar to the CEC, the new construction (Title 24) module calculates adoption based on a housing-start forecast, compliance rate and solar PV system size. The incentive program module calculates solar adoption based on the programmatic budget and solar PV system price. Generation profiles for solar PV were applied to convert the adopted capacity to a forecast of solar PV energy production. It's important to note that PG&E did not make any forecast assumptions about solar PV that may be built as a result of future distribution deferral opportunities. PG&E appreciates the efforts the CPUC is taking so that the 2020 LSE IRP cycle could include demand-side resources (including solar PV) as candidate resources within the IRP optimization, and should carefully consider the costs of integrating solar PV.

The bulk of the difference between the Conforming scenario and PG&E's internal forecast comes from PG&E's use of an updated set of solar PV generation profiles. In 2017, PG&E updated its solar PV generation profiles to integrate more granular meteorological data and to leverage actual system performance data from metered PV systems under the CSI.[52] The solar PV generation profiles used in the Conforming scenario appear to be based on a 2012 E3 Impact Evaluation.[53] This critical input assumption is likely outdated and has not to PG&E's knowledge been calibrated to recent empirical data.

A cursory comparison of the generation profiles suggests that PG&E's updated profile would yield [redacted] percent less energy than the CEC's simulated generation profile for equivalently sized systems.

---

52 PG&E's solar PV generation profiles were developed using customer PV system configuration data and weather data aggregated to the Distribution Planning Area level, which was then translated into a simulated generation profile using the National Renewable Energy Laboratory's PV Watts model. The simulated profiles were then calibrated to metered customer PV generation data available through the California Solar Initiative program. Representative solar PV generation profiles were developed for residential and non-residential customers.

53 CEC California Energy Demand 2018-2030 Revised Forecast, page A-7 (Footnote 105), indicates that CEC's PV performance data is based on "Energy and Environmental Economics, Inc. November 2013. *California Solar Initiative 2012 Impact Evaluation*. Report is forthcoming but staff was provided a draft copy of the report and the simulated PV production data."

Relative to the Conforming scenario, PG&E also accounts for a more gradual phase-in of AAPV in advance of the effective date of the recently adopted 2019 Building Energy Efficiency Standards (Title 24, Part 6) by assuming that permits for housing construction could be filed before the new rooftop solar PV requirements take effect on January 1, 2020. This accounts for the long lag time between permitting and occupancy, particularly for community-scale development. PG&E also assumes a higher exception rate for mandated solar PV on new residential construction than the CEC (30 percent versus 20 percent exception rate).

Non-PV Distributed Generation (DG)

For its Preferred and Alternative scenarios, PG&E used its internal forecast for Non-PV DG. To forecast adoption of wind and combustion technologies, PG&E uses a simple time series method, informed by policy trends, market size assessments, and predicted retirement rates. To forecast adoption of fuel cells, PG&E uses a simplified Bass diffusion model.

Generation profiles for each Non-PV DG technology were applied to the respective technology's adopted capacity to produce a forecast of the Non-PV DG energy production. The generation profiles were developed PG&E based on annual capacity factors from the *2014-2015 Self-Generation Incentive Program Impact Evaluation*.[54]

The difference between the Conforming scenario and PG&E's Preferred and Alternative scenarios Non-PV DG forecast appears to be driven by PG&E's more conservative set of underlying assumptions including policy constraints on adoption of new fossil fuel generation technologies (e.g., combustion turbines, natural gas fuel cells), limited availability of renewable natural gas and retirements of existing facilities.

Electric Vehicles (EV)

For its Preferred and Alternative scenarios, PG&E used its internal forecast for EVs. PG&E's forecast aligns with the state's ambitious goal of deploying 5 million (2 million in PG&E's service territory) light duty electric vehicles on California's roads by 2030, while the Conforming case represents only

54 Itron, November 2016, Final Report: 2014-2015 SGIP Impacts Evaluation (hyperlink at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451496).

3.3 million vehicles (1.3 million in PG&E's service territory). PG&E's forecast also accounts for the dynamic and growing ride share market segment.

PG&E's long-term EV light-duty vehicle (LDV) forecast is developed using a policy scenario model, augmented with a probability model for energy consumption (GWh).[55] This model allows PG&E to assess the energy impacts of various EV LDV adoption scenarios based upon state policy targets. After applying energy consumption parameters, a probabilistic analysis determines the mean or probability-weighted average energy use from LDVs based on charging segmentation (e.g., home charging, DC fast charging (DCFC), and non-DCFC public charging) and driving segmentation (e.g., conventional personal vehicle vs. rideshare).

PG&E and CEC use different modeling approaches, so it is challenging to directly attribute the difference between the Conforming and Preferred and Alternative scenarios. At the most fundamental level, the difference is driven by the total number of vehicles forecast to be adopted and the per-car charging assumptions. PG&E also forecasts growth in the rideshare EV market segment which is assumed to have a higher daily charge rate than personal vehicles.

Community Choice Aggregation and Direct Access

For its Preferred and Alternative scenarios, PG&E used its internal forecast for CCA and combined the forecasted Bay Area Rapid Transit (BART) load with the DA forecast.

PG&E's CCA forecast reflects continued expansion of the large, dynamic and rapidly growing CCA market. The Conforming scenario forecast reflects no expansion of existing CCAs or formation of new CCAs beyond 2019. As a result, the Conforming case projects 20 percent less load served by CCAs in 2030 than PG&E's forecast.

PG&E independently produces a near-term forecast of the load to be served by existing or announced CCAs based on the latest information available regarding CCA implementation plans, opt-out rates, load data and other key inputs. PG&E then consults with those CCAs through a "meet and confer"

55 PG&E did not include Medium and Heavy-Duty Vehicles in its forecast due to the currently low levels of penetration of EVs in these sectors making reliable projections of future adoption challenging.

process to validate and reconcile its forecasts. PG&E supplements this forecast with a probabilistic analysis of the CCA market to quantify the potential impact of additional CCA expansion and formation, based in large part on observed market activity within the PG&E service territory.

The difference between the CCA forecast in the Conforming scenario and PG&E's Preferred and Alternative scenarios is driven by fundamental differences in assumptions about the formation of new CCAs. The Conforming scenario accounts only for currently established CCAs and fails to forecast any expansion of these CCAs or formation of new CCAs. PG&E forecast accounts for the continued CCA expansion and formation.

c) Price Assumptions

The Conforming, Preferred, and Alternative scenarios include PG&E's supply of utility-owned and contracted resources – specifically, existing online resources, resources currently in-development with executed contracts, and forecasted procurement associated with Commission mandated programs.

For the Conforming scenario, PG&E aligned price assumptions for Gas, GHG, and LCOE with the CPUC RSP or CEC 2017 IEPR. For the Preferred and Alternative scenarios, PG&E used internally-developed forecasts.

Prices throughout PG&E's IRP are shown in both nominal values and as 2016 dollars as adjusted by the 2017 IEPR Implicit GDP 2016 Deflator. A summary of price assumptions for year 2030 are shown in the Tables 5 and 6.

TABLE 5
COMPARISON OF 2030 PRICE ASSUMPTIONS ($ NOMINAL)

Line No.	Assumption	Conforming Scenario	Preferred/Alternative Scenarios
1	PG&E City Gate Gas Price	IEPR 2017 ($5.26/MMBtu)	PG&E Internal Forecast ($3.82/MMBtu)
2	GHG Allowance Price	IEPR 2017 ($70.99/MT)	[redacted]
3	Technology Cost (Levelized Cost of Energy)	CPUC RSP Solar: $79/MWh Wind: $114/MWh Geothermal: $118/MWh Storage: $238/kw-yr	

TABLE 6
COMPARISON OF 2030 PRICE ASSUMPTIONS ($ 2016)

Line No.	Assumption	Conforming Scenario	Preferred/Alternative Scenarios
1	PG&E City Gate Gas Price	IEPR 2017 ($3.94/MMBtu)	PG&E Internal Forecast ($2.86/MMBtu)
2	GHG Allowance Price	IEPR 2017 ($53.16/MT)	[redacted]
3	Technology Cost (Levelized Cost of Energy)	CPUC RSP Solar: $60/MWh Wind: $86/MWh Geothermal: $88/MWh Storage: $178/kw-yr	

d) Revenue Requirement Assumptions

The key assumptions for the Revenue Requirement and Rates calculations are listed in Table 7.

TABLE 7
COMPARISON REVENUE REQUIREMENTS AND RATES ASSUMPTIONS

Line No.	Assumption	Conforming/Preferred/ Alternative Scenarios
1	Revenue Fee and Uncollectibles (RF&U)	2018 RF&U factor was held constant at 1.011389 over the planning horizon.
2	IEPR Distribution, Transmission, and Demand-Side Management Programs	Cost for forecast years 2029 and 2030 were held constant at 2028 level for D, T, and DSM Programs.

3. Study Results

This section presents the results of the analytical work described in Section 2 (Study Design).

Portfolio results are presented for the Conforming, Preferred and Alternative scenarios. Given that PG&E is submitting a Preferred portfolio distinct from its Conforming portfolio, PG&E provides analyses of local air pollutant minimization and disadvantaged communities, costs and rates, and local needs for both the Conforming and Preferred scenarios.

As described in Section 2:

- The Conforming scenario reflects the assumptions prescribed by the CPUC including the load forecast and prices. This scenario, as well as the Preferred and Alternative scenarios, reflect resource additions associated with Commission mandated or prescribed procurement (e.g., Bioenergy Market Adjusting Tariff (BioMAT), the Resolution E-4909 local sub-area storage RFO, etc.).
- The Preferred scenario reflects PG&E's internal load forecast and price forecasts. PG&E's internal load forecast includes higher levels of energy efficiency, electric vehicle penetration and CCA load shift as compared to the IEPR forecast. It also includes lower levels of distributed generation. More detail on the prices can be found in the Key Prices sections below, within the description of the results for each of the three scenarios.
- The Alternative scenario is based on the Preferred scenario loads and prices but reflects the impacts of the Green Allocation Mechanism/Portfolio Monetization Mechanism (GAM/PMM) proposal.

For each portfolio, results are shown for:

1. Energy sales forecast;
2. Resource additions;
3. Resource portfolio;
4. Energy requirement and dispatch;
5. Greenhouse gas (GHG) emissions;
6. Renewable portfolio standard (RPS) compliance position;
7. System resource adequacy (RA) position; and
8. Key prices.

The 2030 GHG emission value is calculated using the Commission's CNS Calculator and is presented alongside PG&E's 2030 GHG emissions benchmark for each portfolio.

Results, except for GHG emissions, are presented for years 2018, 2022, 2026, and 2030. Results for each year, 2018 through 2030 can be found in Appendix 3.[56]

Additional information is provided in the Alternative scenario discussion regarding the allocation of RECs and RA.

A. Conforming Scenario

For the Conforming scenario, after accounting for PG&E's existing RPS and GHG-free resources and forecasted procurement from the CPUC's mandated procurement programs, PG&E will not need to procure new resources over the planning period. PG&E's GHG emissions forecast for the entire planning period is below the 2030 GHG emissions benchmark of 6.07 MMT and the RPS requirement can be met with generation from forecasted bundled RPS-eligible resources and banked RECs when needed. The primary reason for the lack of new resource need is load shift to CCAs.

1) Energy Sales Forecast

Pursuant to Commission guidance, the Conforming scenario uses the 2017 IEPR load and load modifier forecasts, as modified in the ALJ's June 18, 2018 Ruling adopting revised CCA load forecasts.[57] As shown in Figure 3, the bundled customer sales forecast for PG&E is expected to decline by 29 percent from 2018 to 2030.[58]

---

56 The positions shown in the IRP represent forecasts of PG&E's physical position and not its economic position. Numbers in tables may not add due to rounding.

57 The 2018 forecast for loads, supply resources and costs is based on the Commission-approved 2018 ERRA Forecast in D.18-01-009 to maintain consistency between PG&E's most recently approved ERRA Forecast and its 2018 IRP forecasts. For all other years of the Conforming scenario, load is based on the 2017 IEPR load.

58 Gross System Usage represents PG&E's sales forecast prior to adjusting for EE, DG, and EVs. Adjustments due to electrification are reflected in the Gross System Usage total. Net System Sales represent PG&E's sales forecast after accounting for those load modifiers. Bundled sales represent PG&E's bundled sales after accounting for DA (including BART) and CCA load.

FIGURE 3
CONFORMING SCENARIO ENERGY SALES FORECAST

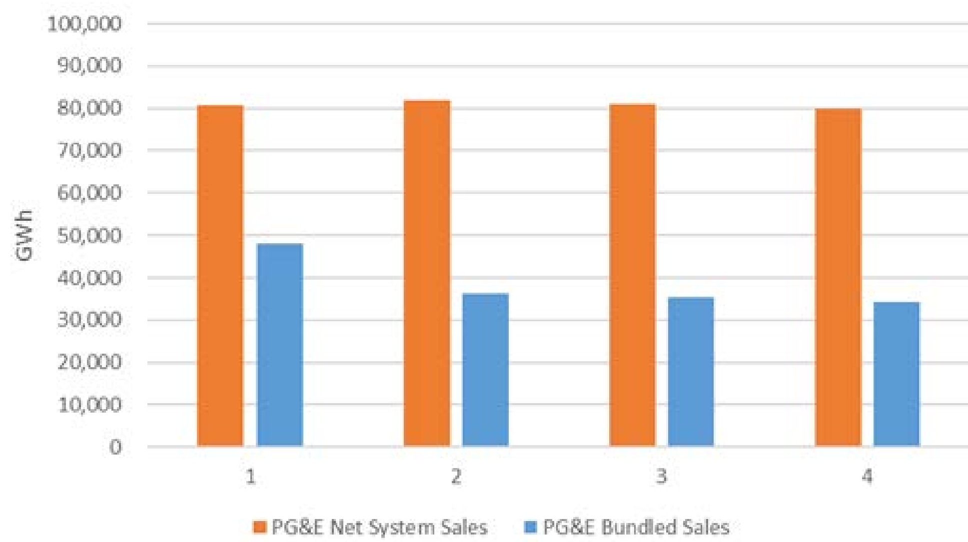


Table 8 shows that expected increases in EE and DG PV offset the sales increase driven by economic and population growth and electric vehicle (EV) demand. This results in Net System Sales for PG&E's service area decreasing slightly from 2018 to 2030. Bundled Sales decrease by about 29 percent from 2018 to 2030, largely driven by the forecasted CCA load shift.

TABLE 8
CONFORMING SCENARIO ENERGY SALES FORECAST (GWH)

Line No.	Description	2018[(a)]	2022	2026	2030
1	PG&E Gross System Usage	87,375	102,149	109,941	116,897
2	Energy Efficiency	(4,147)	(8,894)	(15,930)	(22,573)
3	Distributed Generation	(2,614)	(13,662)	(17,243)	(20,290)
4	Solar PV	(2,395)	(10,012)	(13,487)	(16,459)
5	Non-PV	(220)	(3,650)	(3,756)	(3,831)
6	Electric Vehicles	160	2,353	4,205	5,982
7	PG&E Net System Sales	80,774	81,946	80,973	80,016
8	Direct Access[(b)]	(9,729)	(9,520)	(9,520)	(9,520)
9	Community Choice Aggregation	(23,060)	(36,264)	(36,099)	(36,309)
10	PG&E Bundled Sales	47,986	36,162	35,355	34,187

(a) The 2018 forecast for loads, supply, resources, and costs is based on the CPUC-approved 2018 ERRA Forecast revenue requirement in D.18-01-009 to maintain consistency with the 2018 IRP costs.

(b) Direct Access includes sales to BART.

2) Resource Additions

PG&E plans to add resources as a result of 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 2018 IRP. Table 9 summarizes PG&E's resource additions. The amounts shown are total resource capacities, not reflecting capacity allocations for CAM or resources recovered through distribution rates. 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 9
CONFORMING SCENARIO CUMULATIVE RESOURCE ADDITIONS (MW)

Line No.	Technology	2018	2022	2026	2030
1	Biogas				
2	SB1122/BioMAT	–	42	62	62
3	Biomass				
4	SB1122/BioMAT	–	32	47	47
5	SB32/ReMAT	–	–	34	50
6	Subtotal (Biomass)	–	32	81	97
7	Wind				
8	SB32/ReMAT	–	–	15	22
9	Solar PV				
10	SB32/ReMAT	5	14	44	44
11	GTSR	2	25	25	25
12	RPS (RFO)	170	452	452	452
13	RAM / PV RAM	20	110	110	110
14	Subtotal (Solar PV)	197	601	630	630
15	Storage[a]				
16	AB 2868/ Dist. Connected	[redacted]			
17	AB 2514/ IOU Target	–	95	175	175
18	Res. E-4909/ Local Deficiency	–	568	568	568
19	Subtotal (Storage)	[redacted]			
20	Total Resource Additions				

(a) Storage quantities do not include any storage procurement conducted as part of the Oakland Clean Energy Initiative.

The 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 2018 and 2020.[59]

b. **Mandated RPS Resource Procurement**: PG&E forecasts procurement of additional bioenergy, solar, and wind resources through the Commission's existing mandated procurement programs (BioMAT, Renewable Market Adjusting Tariff (ReMAT), RAM/PV RAM).[60]

c. **Storage Procurement**: PG&E expects to make investments in storage resources that are recoverable through generation or distribution rates. For any storage recoverable through CAM, or for distribution reliability resources (including storage procured pursuant to AB 2868 and Resolution E-4909), a portion of the capacity will be allocated to other LSEs. Table 10 shows PG&E's bundled share of storage capacity, net of the allocations.

PG&E's planning assumption also includes annual sales of approximately 2,000 GWh of RPS-eligible energy. Note that the 2,000 GWh sales assumptions is strictly a planning assumption and does not represent what PG&E will actually execute. 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.

Table 10 shows storage additions, net of CAM and distribution resource allocations.

---

59 PG&E's 2019 ERRA Forecast testimony at Chapter 6 provides an overview of PG&E's RPS-eligible contracts. Hyperlink at: http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=481958.

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.

60 These mandated procurement programs are described in Section 2.2 of PG&E's Final 2017 Renewable Energy Procurement Plan, filed January 17, 2018 in Rulemaking (R.) 15-02-020 (hyperlink at: http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=435554). 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 render ReMAT compliant with PURPA.

TABLE 10
PG&E STORAGE ADDITIONS NET OF CAM AND DISTRIBUTION ALLOCATION (MW)

Line No.	Description	2018	2022	2026	2030
1	AB 2868/Dist. Connected	[redacted]	[redacted]	[redacted]	[redacted]
2	AB 2514/IOU Target	[redacted]	95	163	163
3	Res. E-4909/Local Deficiency	[redacted]	255	237	231
4	Bundled Portfolio	[redacted]	[redacted]	[redacted]	[redacted]

Note that the storage additions assumed in Table 9 are attributable to either existing procurement requirements (e.g., AB 2514, Resolution E-4909) or other procurement proposals already made by PG&E (e.g., AB 2868). 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.

3) Resource Portfolio

The total capacity of generating resources in PG&E's portfolio is expected to decline from 2018 to 2030. Table 11 shows the capacity of utility-scale resources declining by 7,303 MW from 19,778 MW in 2018 to 12,475 MW by 2030. The amounts shown are total resource capacity, not reflecting capacity allocations for CAM or distribution resources.

TABLE 11
CONFORMING SCENARIO TOTAL PORTFOLIO RESOURCES BY TECHNOLOGY (MW)

Line No.	Technology	2018	2022	2026	2030
1	Solar	4,048	4,427	4,457	4,447
2	Large Hydro[(a)]	[redacted]			
3	Nuclear	2,240	2,240	0	0
4	Wind	1,912	1,705	1,310	1,167
5	Storage	[redacted]			
6	Pumped Storage				
7	Small Hydro	577	482	467	439
8	Biomass	301	260	246	217
9	Geothermal	272	22	22	22
10	Biogas	50	79	95	92
11	Natural Gas (CHP)	[redacted]			
12	Natural Gas (Non-CHP)				
13	Total	19,778	18,651	13,366	12,475

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

The decline in capacity is primarily driven by the decline in natural gas-fired, nuclear, and wind resources. The reduction of 5,093 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/Combined Heat and Power (CHP) Settlement Agreement or the Long-Term Procurement Plan proceeding. In 2018, the Commission approved the retirement of DCPP, which will reduce PG&E's nuclear capacity to zero in 2025.[61] The 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 will not be needed in order for PG&E to meet its RPS compliance requirements.

4) Energy Requirement and Dispatch

The total load requirement and energy generation forecast from resources in the Conforming portfolio are shown in Table 12.

61 D.18-01-022.

The data includes both forecasted generation from GHG-free resources that are included as part of the CNS calculation[62] as well as generation from dispatchable natural-gas fired and out-of-state (OOS) wind resources. Also reflected are annual sales of approximately 2,000 GWh of RPS-eligible energy. Based on the load requirement and expected generation shown, PG&E will be a net seller of energy to the CAISO in years 2018 through 2024, and a net buyer of energy beginning in 2025.

62 Pursuant to Attachment A to the ALJ's May 25, 2018 Ruling available here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M214/K861/214861583.PDF, GHG-free resources in the CNS methodology are: "RPS Bucket 1, hydroelectric, and nuclear generation, and any other RPS-eligible resources that meet the criteria to qualify as RPS Bucket 1…resources can count as GHG-free only if delivered to a California balancing authority area except for the contract execution date of the resource."

TABLE 12
CONFORMING SCENARIO ENERGY BALANCE (GWH)

Line No.	Description	2018	2022	2026	2030
1	Energy Load				
2	PG&E Bundled Sales	47,986	36,162	35,355	34,187
3	Losses (T&D + UFE)	4,359	3,408	3,316	3,183
4	Total Load Requirement	52,345	39,571	38,671	37,370
5	Energy Supply				
6	GHG-Free Resources				
7	Solar	9,167	10,451	10,298	10,065
8	Large Hydro[a]	[redacted]	[redacted]	[redacted]	[redacted]
9	Nuclear	[redacted]	[redacted]	–	–
10	Wind	2,967	2,741	2,445	2,033
11	Storage[b]	[redacted]	[redacted]	[redacted]	[redacted]
12	Small Hydro	1,965	1,609	1,580	1,520
13	Biomass	1,750	1,694	1,538	1,358
14	Geothermal	2,320	152	149	145
15	Biogas	273	497	548	529
16	CHP	[redacted]	[redacted]	[redacted]	[redacted]
17	RPS Sales[c]	–	(2,069)	(2,069)	(2,069)
18	Subtotal GHG-free and Non-dispatchable Resources	[redacted]	[redacted]	[redacted]	[redacted]
19	Other Resources				
20	Non-UOG Fossil	[redacted]	[redacted]	[redacted]	[redacted]
21	UOG Fossil	[redacted]	[redacted]	[redacted]	[redacted]
22	UOG Fuel Cell	[redacted]	[redacted]	[redacted]	[redacted]
23	Wind (OOS)	939	727	–	–
24	Subtotal Other	[redacted]	[redacted]	[redacted]	[redacted]
25	Market Sales / (Purchases)	[redacted]	7,704	(10,644)	(13,573)
26	Total Energy Supply	52,345	39,571	38,671	37,370

(a) Hydro generation reduction is driven by contract expirations and reduction in expected generation starting 2019 based on an updated historical 30-year average for the UOG hydro resources.

(b) Net energy from Helms pump storage resource. Energy impact from batteries not included since these resources are primarily capacity-only contracts. For any batteries where PG&E has rights to the energy, PG&E's market purchases will be reduced.

(c) RPS sales assumptions 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 approved RPS sales framework, market demand, and market prices).

2018 reflects PG&E's November 2017 ERRA update to its 2018 forecast year, and does not reflect sales since fall 2017.

5) Greenhouse Gas Emissions

Based on the Conforming scenario load and mix of resources, PG&E's forecasted 2030 GHG emissions using the CNS methodology is 4.72 MMT. This value is below PG&E's 2030 GHG emissions benchmark of 6.07 MMT.

PG&E attempts to sell its long positions, consistent with its obligations under the BPP, however for certain products and periods of time there are no buyers. Therefore, for purposes of this IRP, PG&E is modeling its energy sales primarily as CAISO market sales, except for approximately 2,000 GWh/year of RPS eligible energy sales. Due to this modeling choice, the GHG-free attributes of additional long positions accrue to PG&E's bundled load in the CNS calculation for the Conforming and Preferred scenarios (in the Alternative scenario, PG&E is modeling allocation of the RPS and large hydro energy, consistent with the Joint IOUs' GAM/PMM proposal).[63]

6) Renewable Portfolio Standard Compliance Position

PG&E will meet its RPS requirement with physical deliveries from resources that are either currently in its portfolio, resources expected to be added from future procurement already mandated or authorized by the Commission, or with banked RECs. Figure 4 and Table 13 show PG&E's forecasted RPS compliance position and renewable physical net short.[64]

For planning purpose, PG&E forecasts selling approximately 2,000 GWh of bundled RECs per year through the planning horizon, with the impact on its bundled supply position reflected in its annual net RPS generation forecast. PG&E anticipates actual sales levels will differ from the forecast based on bundled load and market conditions. As noted above, the 2,000 GWh 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

63 In reality, some of these future energy sales of GHG-free energy may be via forward sales where the counterparty would then be able to include the GHG-free attributes in their own LSE IRPs. Given significant uncertainty in the market demand for these products, uncertainty in the outcome of the PCIA OIR, and the challenge of showing a transfer of attributes among LSEs in this round of the IRP, PG&E believes this modeling assumption is appropriate.

64 PG&E maintains its voluntary commitment proposed in the Joint Proposal to the DCPP Retirement Application to reach 55 percent RPS starting in 2031. Meeting this voluntary commitment was not modeled in this LSE Plan since 2031 is beyond the planning horizon.

(e.g., limits under PG&E's pre-approved RPS sales framework, market demand, market pricing).

FIGURE 4
CONFORMING SCENARIO RENEWABLE COMPLIANCE POSITION

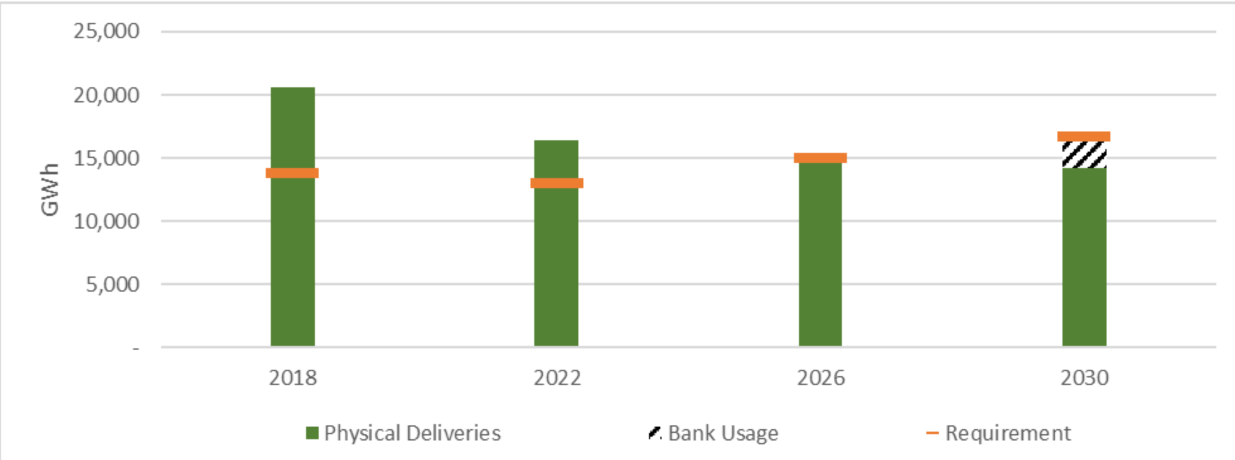


TABLE 13
CONFORMING SCENARIO RENEWABLE COMPLIANCE POSITION

Line No.	Description	2018	2022	2026	2030
1	RPS Physical Deliveries (GWh)[(a)]	20,579	16,416	15,183	14,230
2	RPS Requirement (GWh)	13,816	13,028	14,974	16,695
3	Renewable Physical Net Short (GWh)	6,763	3,388	209	(2,466)
4	RPS Position (%)[(b)]	43.2%	46.0%	43.9%	50.0%
5	RPS Requirement (%)	29.0%	36.5%	43.3%	50.0%

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

(b) RPS Position percentage is based on physical deliveries and the use of RPS bank.

7) System Resource Adequacy Position

Figure 5 shows PG&E's system resource adequacy (RA) position. The position reflects PG&E's share of RA after CAM and distribution resource allocations. The forecast includes RA sales for the years 2018 through 2025.[65] Starting in year 2026, PG&E will need to procure System RA and PG&E forecasts this need will be met through market purchases from existing resources.

FIGURE 5
CONFORMING SCENARIO SYSTEM RA POSITION
BASED ON AUGUST NET QUALIFYING CAPACITY

[redacted]

8) Key Prices

Table 14 and Table 15 below provide commodity prices used in the rate analysis for the Conforming scenario. The use of the 2017 IEPR natural gas fuel price and GHG allowance prices were prescribed by the Commission for the Conforming scenario. The Energy and REC prices are derived using the 2017 IEPR gas and GHG prices, renewable technology costs from RESOLVE, and the system portfolio identified in the RSP.

---

65 2018 shows PG&E's RA position as of the November 2017 ERRA update to its 2018 forecast year. The 2018 position does not include sales made since fall 2017. PG&E's 2019 onward position incorporates executed RA sales for years 2019-2022 as of June 1, 2018. PG&E seeks to dispose of its long RA product positions consistent with the procurement processes and methods set forth in its BPP. There is no guarantee that PG&E's long RA products will be purchased by buyers

PG&E developed capacity price forecasts based on scenario specific system data from RESOLVE and by applying PG&E's Capacity Price Forecast Tool. Based on the resource assumptions contained in the RSP, capacity prices were modeled at the short-run cost through 2030.

TABLE 14
CONFORMING SCENARIO COMMODITY PRICES ($ NOMINAL)

Line No.	Description	Unit	2018	2022	2026	2030
1	PGE Citygate Gas Price[a]	$/MMBtu	$3.23	$3.91	$4.52	$5.26
2	GHG Allowance Price	$/MT	$15.38	$24.63	$41.82	$70.99
3	On-Peak Energy Price	$/MWh	$36.73	$31.43	$40.46	$44.83
4	Off-Peak Energy Price	$/MWh	$32.25	$33.71	$46.84	$55.12
5	REC Price	$/MWh	$14.19	$44.52	$59.05	$64.82
6	System RA Price	$/kw-year	$14.61	$31.15	$32.16	$47.25

(a) Source: http://www.energy.ca.gov/2014publications/CEC-200-2014-008/Model_CEC-200-2014-008.xlsm.

TABLE 15
CONFORMING SCENARIO COMMODITY PRICES ($ 2016)

Line No.	Description	Unit	2018	2022	2026	2030
1	PGE Citygate Gas Price[a]	$/MMBtu	$3.09	$3.42	$3.66	$3.94
2	GHG Allowance Price	$/MT	$14.73	$21.54	$33.85	$53.16
3	On-Peak Energy Price	$/MWh	$35.17	$27.48	$32.75	$33.57
4	Off-Peak Energy Price	$/MWh	$30.88	$29.48	$37.91	$41.27
5	REC Price	$/MWh	$13.59	$38.93	$47.79	$48.54
6	System RA Price	$/kw-year	$13.99	$27.24	$26.03	$35.38

(a) Source: http://www.energy.ca.gov/2014publications/CEC-200-2014-008/Model_CEC-200-2014-008.xlsm.

Note that the market prices reflected in the Conforming scenario, which are based on the CEC's 2017 IEPR and CPUC's RSP inputs, do not represent PG&E's internal view of future market prices. For this reason, PG&E has adjusted the commodity;

price forecasts based on its internal view in its Preferred and Alternative scenarios, as described in the "Key Prices" sections.

B. Preferred Scenario

PG&E's Preferred scenario reflects PG&E's internal load forecast.[66] PG&E's internal load forecast includes higher levels of energy efficiency, electric vehicle penetration and CCA departure as compared to the IEPR forecast. It also includes reduced levels of distributed generation. Although the components of the load forecasts differ, the total bundled load for the Preferred scenario in 2030 (33,784 GWh) is similar to the Conforming scenario (34,187 GWh). Additional discussion of the Preferred scenario load forecast and how it differs from the IEPR forecast can be found in Section 2 (Study Results).

Since the load and assumed cost recovery mechanisms in the Preferred scenario are similar to the Conforming scenario, the high-level takeaway from the scenarios are also similar. PG&E will not need to procure new, utility-scale resources over and above the CPUC's current mandated procurement programs during the planning period. PG&E's GHG emissions forecast for the entire planning period is below the Conforming scenario-adjusted 2030 GHG emissions benchmark for the Preferred scenario of 5.50 MMT. The RPS requirement will be met with physical deliveries from expected bundled RPS-eligible resources and banked RECs when needed. As with the Conforming scenario, the primary reason for the lack of new resource need is load shift to CCAs.

1) Energy Sales Forecast

As shown in Figure 6, the Bundled Customer sales forecast for PG&E is expected to decline by 30 percent from 2018 to 2030.

66 See Footnote 57.

FIGURE 6
PREFERRED SCENARIO ENERGY LOAD FORECAST

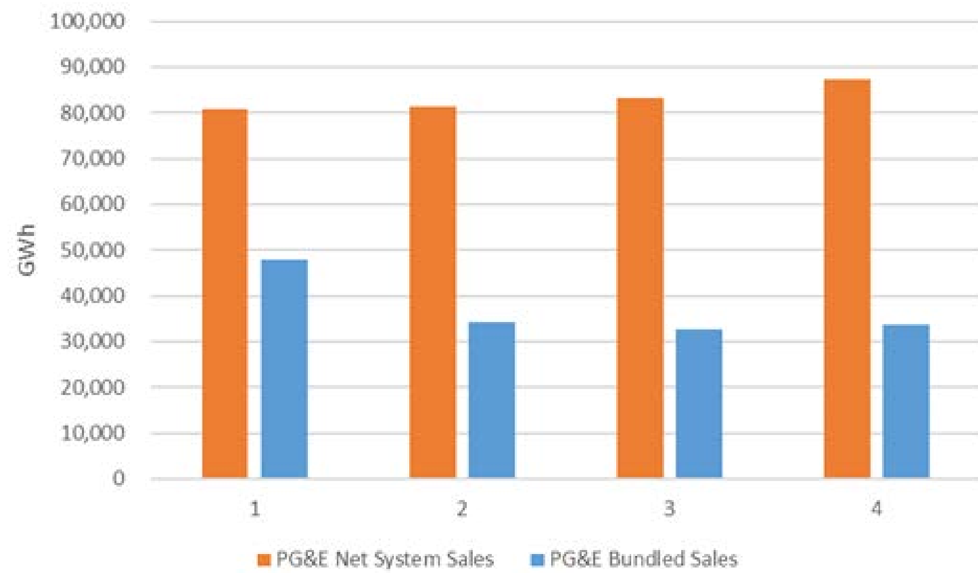


Table 16 shows that the expected increases in EE and DG-solar PV offset a majority of the growth in electric vehicle (EV) demand, as well as economic and population driven growth, resulting in Net System Sales for PG&E's service area increasing by 8 percent from 2018 to 2030. CCA load shift is forecasted to increase from 23,060 GWh in 2018 to 43,456 GWh by 2030, reducing bundled sales.

TABLE 16
PREFERRED SCENARIO PG&E ENERGY SALES FORECAST (GWH)

Line No.	Description	2018	2022	2026	2030
1	PG&E Gross System Usage	87,375	[redacted]	[redacted]	[redacted]
2	Energy Efficiency	(4,147)	[redacted]	[redacted]	[redacted]
3	Distributed Generation	(2,614)	[redacted]	[redacted]	[redacted]
4	Solar PV	(2,395)	[redacted]	[redacted]	[redacted]
5	Non-PV	(220)	[redacted]	[redacted]	[redacted]
6	Electric Vehicles	160	[redacted]	[redacted]	[redacted]
7	PG&E Net System Sales	80,774	81,489	83,197	87,291
8	Direct Access[(a)]	(9,729)	(10,051)	(10,051)	(10,051)
9	Community Choice Aggregation	(23,060)	(37,268)	(40,451)	(43,456)
10	PG&E Bundled Sales	47,986	34,169	32,694	33,784

(a) Direct Access includes sales to BART.

2) Resource Additions

PG&E's resource additions for the Preferred portfolio are the same as that reflected in the Conforming portfolio and can be seen in Table 9 above.

3) Resource Portfolio

PG&E's bundled resource portfolio for the Preferred scenario is the same as that reflected in the Conforming portfolio and can be seen in Table 11.

4) Energy Requirement and Dispatch

The total load requirement and the energy generation from resources in the Preferred scenario are shown in Table 17. As expected, these amounts are similar to the values for the Conforming scenario. PG&E is forecasted to become a net energy buyer in 2026.

TABLE 17
PREFERRED SCENARIO ENERGY BALANCE (GWH)

Line No.	Description	2018	2022	2026	2030
1	Energy Load				
2	PG&E Bundled Sales	47,986	34,169	32,694	33,784
3	Losses (T&D + UFE)	4,359	3,111	2,998	3,138
4	Total Load Requirement	52,345	37,281	35,692	36,922
5	Energy Supply				
6	CNS GHG-free Resources				
7	Solar	9,167	10,451	10,298	10,065
8	Large Hydro[a]	[redacted]	[redacted]	[redacted]	[redacted]
9	Nuclear	[redacted]	[redacted]	-	-
10	Wind	2,967	2,741	2,445	2,033
11	Storage[b]	[redacted]	[redacted]	[redacted]	[redacted]
12	Small Hydro	1,965	1,609	1,580	1,520
13	Biomass	1,750	1,694	1,538	1,358
14	Geothermal	2,320	152	149	145
15	Biogas	273	497	548	529
16	CHP	[redacted]	[redacted]	[redacted]	[redacted]
17	RPS Sales[c]	–	(2,069)	(2,069)	(2,069)
18	Subtotal CNS GHG-free Resources	[redacted]	[redacted]	[redacted]	[redacted]
19	Other Resources				
20	Non-UOG Fossil	[redacted]	[redacted]	[redacted]	[redacted]
21	UOG Fossil	[redacted]	[redacted]	[redacted]	[redacted]
22	UOG Fuel Cell	[redacted]	[redacted]	[redacted]	[redacted]
23	Wind (OOS)	939	727	–	–
24	Subtotal Other	[redacted]	[redacted]	[redacted]	[redacted]
25	Market Sales / (Purchases)	[redacted]	10,747	(6,373)	(11,939)
26	Total Energy Supply	52,345	37,281	35,692	36,922

(a) Hydro generation reduction is driven by contract expirations and reduction in expected generation starting 2019 based on an updated historical 30-year average for the UOG hydro resources.

(b) Net energy from Helms pump storage resource. Energy impact from batteries not included since these resources are primarily capacity-only contracts.

(c) 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).

2018 reflects PG&E's November 2017 ERRA update to its 2018 forecast year, and does not reflect sales since fall 2017.

5) Greenhouse Gas Emissions

Based on the Preferred scenario load and mix of resources, PG&E's forecasted 2030 GHG emissions using the CNS methodology is 4.59 MMT. This value is below PG&E's 2030 Preferred scenario GHG emissions benchmark of 5.50 MMT. The Preferred benchmark is 0.57 MMT lower than the Conforming benchmark, due to a reduction in PG&E's share of Net System Sales (see discussion in Section 2.B.2).

6) Renewable Portfolio Standard Compliance Position

As with the Conforming scenario, PG&E will meet its RPS requirement with physical deliveries from resources that are either currently in its portfolio, resources expected to be added from future procurement already authorized by the Commission, or with banked RECs. Figure 7 and Table 18 show PG&E's forecasted RPS compliance position and requirement.

As described in the Conforming scenario, for planning purposes, PG&E forecasts selling approximately 2,000 GWh of bundled RECs per year through the planning horizon, with the impact on its bundled supply position reflected in its annual net RPS generation forecast.

FIGURE 7
PREFERRED SCENARIO RENEWABLE COMPLIANCE POSITION

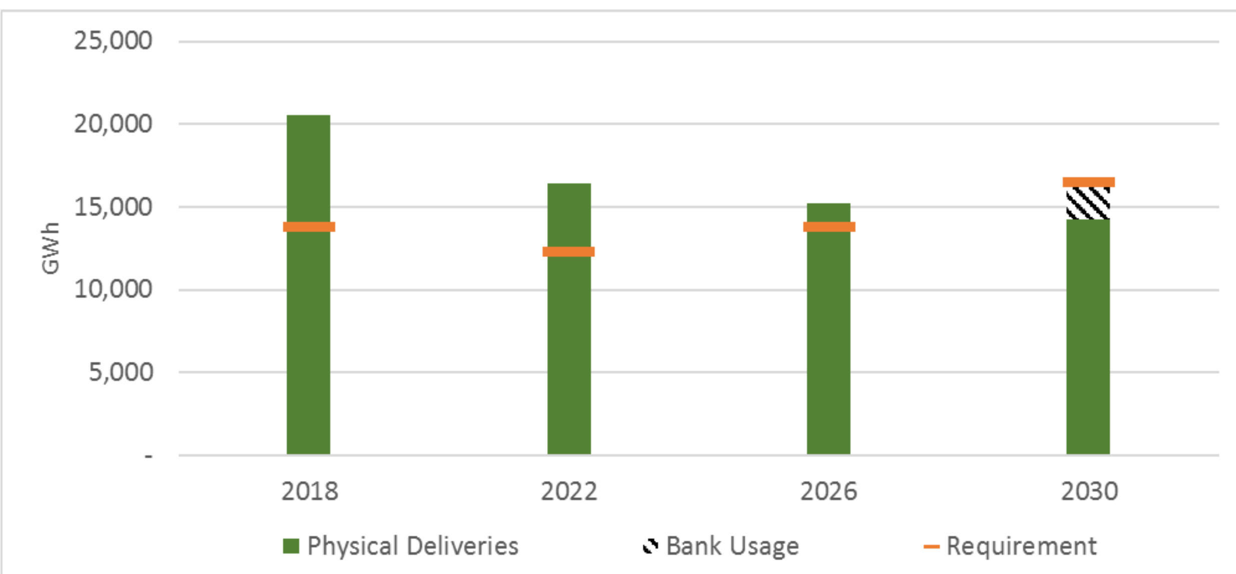


TABLE 18
PREFERRED SCENARIO RENEWABLE COMPLIANCE POSITION

Line No.	Description	2018	2022	2026	2030
1	RPS Physical Deliveries (GWh)[(a)]	20,579	16,416	15,183	14,230
2	RPS Requirement (GWh)	13,816	12,300	13,821	16,494
3	Renewable Physical Net Short (GWh)	6,763	4,115	1,361	(2,264)
4	RPS Position (%)[(b)]	43.2%	48.7%	47.6%	50.0%
5	RPS Requirement (%)	29.0%	36.5%	43.3%	50.0%

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

(b) RPS Position percentage is based on physical deliveries and the use of RPS bank.

7) System Resource Adequacy Position

Figure 8 shows PG&E's system RA position. The position is similar to the Conforming scenario.[67] Starting in 2027, PG&E forecasts a system RA procurement need that will be met through market purchases from existing resources.

67 2018 shows PG&E's RA position as of the November 2017 ERRA update to its 2018 forecast year. The 2018 position does not include sales made since fall 2017. PG&E's 2019 onward position incorporates executed RA sales for years 2019-2022 as of June 1, 2018. PG&E seeks to dispose of its long RA product positions consistent with the procurement processes and methods set forth in its BPP. There is no guarantee that PG&E's long RA products will be purchased by buyers.

FIGURE 8
PREFERRED SCENARIO SYSTEM RA POSITION
BASED ON AUGUST NET QUALIFYING CAPACITY

[redacted]

As stated above, PG&E's 2018 IRP only includes energy storage needed to meet existing procurement requirements (e.g., AB 2514, Resolution E-4909) or other procurement proposals already made by PG&E (e.g., AB 2868). 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.

8) Key Prices

Tables 19 and 20 below provide commodity prices used in the rate analysis for the Preferred scenario. The PG&E City Gate gas prices and GHG allowance prices are PG&E internally-generated forward prices. The Energy and REC prices are calculated using these gas and GHG prices, PG&E's internal renewable technology costs, and the system portfolio identified in the RSP. REC prices are significantly lower in the Preferred scenario than in the Conforming scenario because of PG&E's lower renewable technology cost forecast.

TABLE 19
PREFERRED SCENARIO COMMODITY PRICES ($ NOMINAL)

Line No.	Description	Unit	2018	2022	2026	2030
1	PGE Citygate Gas Price	$/MMBtu	[redacted]	$3.20	$3.53	$3.82
2	GHG Allowance Price	$/MT	[redacted]	[redacted]	[redacted]	[redacted]
3	On-Peak Energy Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]
4	Off-Peak Energy Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]
5	REC Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]
6	System RA Price	$/kw-year	[redacted]	[redacted]	[redacted]	[redacted]

TABLE 20
PREFERRED SCENARIO KEY COMMODITY PRICES ($ 2016)

Line No.	Description	Unit	2018	2022	2026	2030
1	PGE Citygate Gas price	$/MMBtu	[redacted]	$2.79	$2.86	$2.86
2	GHG Allowance Price	$/MT	[redacted]	[redacted]	[redacted]	[redacted]
3	On-Peak Energy Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]
4	Off-Peak Energy Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]
5	REC Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]
6	System RA Price	$/kw-year	[redacted]	[redacted]	[redacted]	[redacted]

C. Alternative Scenario

The Alternative scenario starts with the Preferred scenario load forecast and resource assumptions but allocates/auctions resource attributes in accordance with the Joint IOU's GAM/PMM proposal[68] as follows, on a vintage basis.

- Under GAM, an allocation mechanism, departed load's share of:
  - RECs are allocated for RPS-eligible resources;
  - RA is allocated for RPS-eligible resources and large hydro, including Helms; and
  - Energy is monetized in the CAISO market for RPS-eligible resources and large hydro, including Helms.
- Under the PMM, a monetization mechanism, departed load's share of:
  - RA is auctioned for PCIA-eligible fossil and nuclear resources; and

68 See, Joint IOUs' Prepared Testimony, dated April 2, 2018, in R.17-06-026.

- Energy is monetized in the CAISO market for PCIA-eligible fossil and nuclear resources.

For purposes of counting GHG-free attributes in meeting the CNS planning target, PG&E is not counting the attributes for departed load's share of RPS-eligible resources and large hydro, including Helms. PG&E is counting departed load's share of DCPP's GHG-free attributes in its CNS calculation for this IRP.[69]

As a result of the REC and RA allocations, PG&E forecasts a need to procure GHG-free/RPS eligible resources in addition to those resources already authorized or planned as described in the Preferred scenario.

In the Alternative scenario, PG&E shows a short position for RPS and RA almost immediately, beginning in 2019. PG&E uses its REC bank for RPS compliance through 2023, and has a need for additional physical RPS deliveries is forecasted in 2024.[70] As described below, the Alternative scenario includes approximately 4,800 MW of incremental renewable resources above the Preferred scenario through 2030. Through this additional GHG-free procurement, PG&E is able to meet both its RPS targets through 2030 and its 2030 GHG planning target. PG&E's open RA position is assumed to be met with market purchases.

PG&E limited its resource selection for the Alternative scenario to resources specified in the updated RSP developed for the Preferred and Alternative scenarios (see Assumptions in Design section). Consequently, the resources from which PG&E selected included one-hour-discharge batteries, but not four-hour-discharge (4-hour) batteries. Additional analysis shows that if 4-hour batteries are an option, PG&E would procure up to 1,000 MW of batteries and reduce its solar procurement by a commensurate amount, from approximately 4,000 MW to 3,000 MW. The same amount of wind resources would be procured (about 800 MW). This portfolio with 4-hour batteries is a lower cost option to meeting the RPS, GHG, and RA constraints, given that the 4-hour batteries count for RA and reduce the need for RA market purchases.

As described elsewhere, if the Joint IOUs' GAM/PMM proposal is fully adopted by the Commission in R.17-06-026, PG&E plans to seek procurement authorization from the

---

69 See Footnote 26.

70 The bank usage and resulting need for new RPS deliveries described here are presented for planning purposes only. They do not represent a determination of PG&E's RPS commercial procurement and banking strategy, which is detailed in PG&E's Annual RPS Procurement Plan Filings.

Commission to execute an RPS procurement solicitation before the filing of its next IRP. PG&E will seek a technology-neutral procurement process to select the least-cost best-fit resources to fulfill PG&E's RPS compliance requirements. Given that bid prices and market value may differ between the planning and procurement stages, PG&E may not end up procuring the specific levels of each RPS specific technology modeled in this IRP scenario.

1) Energy Sales Forecast

PG&E's energy sales forecast for the Alternative scenario is the same sales forecast used in the Preferred scenario and reflects higher EV penetration and CCA departures relative to the Conforming portfolio. Figure 6 and Table 16 provide information on the sales forecast for the Preferred and Alternative scenarios.

2) Allocated RECs and RA under GAM/PMM

In the Alternative scenario, REC and RA attributes are allocated in accordance with the GAM and PMM proposals. Under the GAM, RECs are allocated to departing load based on load share and the date of departure from PG&E bundled service. Similarly, RA for both RPS-qualifying resources and large hydro are allocated in GAM. Under PMM, departed load's share of RA from PCIA-eligible fossil and nuclear resources are monetized through auctions. The Alternative scenario reduces PG&E's RA portfolio to reflect the GAM allocation and PMM RA auctions. Table 21 shows the allocated amounts of REC and RA.

TABLE 21
ALTERNATIVE SCENARIO RENEWABLE ENERGY CREDIT AND RESOURCE ADEQUACY AGGREGATE ALLOCATION TO DEPARTED LOAD

Line No.	Description	2018	2022	2026	2030
1	REC (GWh)	0	9,505	9,119	8,747
2	RA (MW, August NQC)	0	2,858	3,035	3,052

3) Resource Additions

As a result of the allocation of REC and RA attributes to departing load under this scenario, PG&E is forecasted to procure approximately 4,800 MW of incremental renewable resources within the planning horizon. Table 22 shows the resource additions beyond those shown in the Preferred scenario needed to meet RPS requirements and the GHG emissions benchmark. Table 23 shows the total resource additions for the Alternative scenario. The totals include the incremental resources shown in Table 22 and the mandated resources shown for the Conforming and Preferred scenarios in Table 9.

TABLE 22
ALTERNATIVE SCENARIO INCREMENTAL RESOURCE ADDITIONS (MW)[(a)]

Line No.	Description	2024	2025	2026	2027	2028	2029	2030	Total
1	New Solar	1,993	26	140	175	166	129	1,371	3,999
2	New Wind	250	73	0	77	55	267	101	822
3	Total	2,243	99	140	251	221	396	1,472	4,821
4	Cumulative Total	2,243	2,342	2,481	2,733	2,954	3,349	4,821	

(a) PG&E's resources additions are a planning level estimate. PG&E might not procure the specific levels of each RPS technology modeled in the alternative scenario due to changes in bid prices and market value between the planning and procurement stages.

TABLE 23
ALTERNATIVE SCENARIO TOTAL RESOURCE ADDITIONS (MW)

Line No.	Description	2018	2022	2026	2030
1	Bioenergy	0	74	143	158
2	Wind	0	0	338	844
3	Solar PV	197	601	2,789	4,629
4	Storage	[redacted]			
5	Total				

As described above, PG&E's 2018 IRP only includes energy storage needed to meet: (1) existing procurement requirements (e.g., AB 2514, Resolution E-4909); or (2) other procurement proposals already made by PG&E (e.g., AB 2868). 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.

When PG&E is ready to go to market to procure, price forecasts, bundled load, and other factors will likely be different than assumptions made in this IRP, and therefore, will result in deviations from resource additions modeled in PG&E's IRP.

Generally, PG&E shows these resource additions as indicative planning results, not specific technologies PG&E expects to procure.

4) Resource Portfolio

PG&E's bundled resource portfolio for the Alternative scenario is shown in Table 24 and reflects the total resource additions in Table 23. The amounts shown in Table 24 are total resource capacities, not reflecting capacity allocations for CAM, GAM or distribution resources and RA sales via the PMM proposal. Table 25 shows PG&E's total resource capacity after CAM, GAM and distribution allocations and PMM sales.

TABLE 24
ALTERNATIVE SCENARIO CUMULATIVE RESOURCES BY TECHNOLOGY (MW)

Line No.	Description	2018	2022	2026	2030
1	Solar	4,048	4,427	4,457	4,447
2	Incremental Solar	0	0	2,158	3,999
3	Large Hydro(a)	[redacted]			
4	Nuclear	2,240	2,241	0	0
5	Wind	1,912	1,705	1,310	1,167
6	Incremental Wind	0	0	323	822
7	Storage	[redacted]			
8	Pumped Storage (Helms)				
9	Small Hydro	577	482	467	439
10	Biomass	301	260	246	217
11	Geothermal	272	22	22	22
12	Biogas	50	79	95	92
13	Natural Gas (CHP)	[redacted]			
14	Natural Gas (Non-CHP)				
15	Total	19,778	18,651	15,848	17,296

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

TABLE 25
ALTERNATIVE SCENARIO CUMULATIVE RESOURCES
BY TECHNOLOGY NET OF ALLOCATIONS AND SALES (MW)

Line No.	Description	2018	2022	2026	2030
1	Solar	4,048	2,180	1,982	1,901
2	Incremental Solar	0	0	2,158	3,999
3	Large Hydro	[redacted]			
4	Nuclear	2,240	1,003	0	0
5	Wind	1,912	787	604	522
6	Incremental Wind	0	0	323	822
7	Storage	[redacted]			
8	Pumped Storage (Helms)				
9	Small Hydro	577	241	219	209
10	Biomass	301	145	150	122
11	Geothermal	272	11	10	10
12	Biogas	50	70	61	56
13	Natural Gas (CHP)	[redacted]			
14	Natural Gas (Non-CHP)				
15	Total	19,778	9,106	8,303	10,195

5) Energy Requirement and Dispatch

The total load requirement and the energy generation from the mix of resources in the Alternative scenario are shown in Table 26. The renewable generation amounts are significantly higher than the Preferred scenario due to need for additional renewable resources resulting from the GAM allocation. The additional energy generation is identified as “Incremental Solar” and “Incremental Wind.” Energy that is sold and monetized for GAM/PMM resources is identified as “GAM/PMM Energy Sales”. After the sales of GAM/PMM energy, PG&E is forecasted to be a net purchaser of energy starting in 2019.[71]

71 PG&E’s net energy position reflects a reduction of energy available to serve PG&E’s bundled load due to the PAM/PMM energy sales.

TABLE 26
ALTERNATIVE SCENARIO ENERGY BALANCE (GWH)

Line No.	Description	2018	2022	2026	2030
1	Energy Load				
2	PG&E Bundled Sales	47,986	34,169	32,694	33,784
3	Losses (T&D + UFE)	4,359	3,111	2,998	3,138
4	Total Load Requirement	52,345	37,281	35,692	36,922
5	Energy Supply				
6	CNS GHG-free Resources				
7	Solar	9,167	10,451	10,298	10,065
8	Incremental Solar	–	–	5,807	11,179
9	Large Hydro[a]	[redacted]	[redacted]	[redacted]	[redacted]
10	Nuclear	[redacted]	[redacted]	–	–
11	Wind	2,967	2,741	2,445	2,033
12	Incremental Wind	–	–	714	2,290
13	Storage[b]	[redacted]	[redacted]	[redacted]	[redacted]
14	Small Hydro	1,965	1,609	1,580	1,520
15	Biomass	1,750	1,694	1,538	1,358
16	Geothermal	2,320	152	149	145
17	Biogas	273	497	548	529
18	CHP	[redacted]	[redacted]	[redacted]	[redacted]
19	RPS Sales[c]	–	–	–	–
20	GAM/PMM Energy Sales	–	(27,930)	(17,959)	(15,575)
21	Subtotal CNS GHG-free and CHP Resources	[redacted]	[redacted]	[redacted]	[redacted]
22	Other Resources	[redacted]	[redacted]	[redacted]	[redacted]
23	Non-UOG Fossil	[redacted]	[redacted]	[redacted]	[redacted]
24	UOG Fossil	[redacted]	[redacted]	[redacted]	[redacted]
25	UOG Fuel Cell	[redacted]	[redacted]	[redacted]	[redacted]
26	Wind (OOS)	939	727	–	–
27	Subtotal Other	[redacted]	[redacted]	[redacted]	[redacted]
28	Market Sales / (Purchases)	[redacted]	(15,113)	(15,743)	(11,976)
29	Total Energy Supply	52,345	37,281	35,692	36,922

(a) Hydro generation reduction is driven by contract expirations and reduction in expected generation starting 2019 based on an updated historical 30-year average for the UOG hydro resources.

(b) Net energy from Helms Pumped Storage. Energy impact from batteries not included since these resources are primarily capacity-only contracts.

(c) 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).

2018 reflects PG&E's November 2017 ERRA update to its 2018 forecast year, and does not reflect sales since fall 2017.

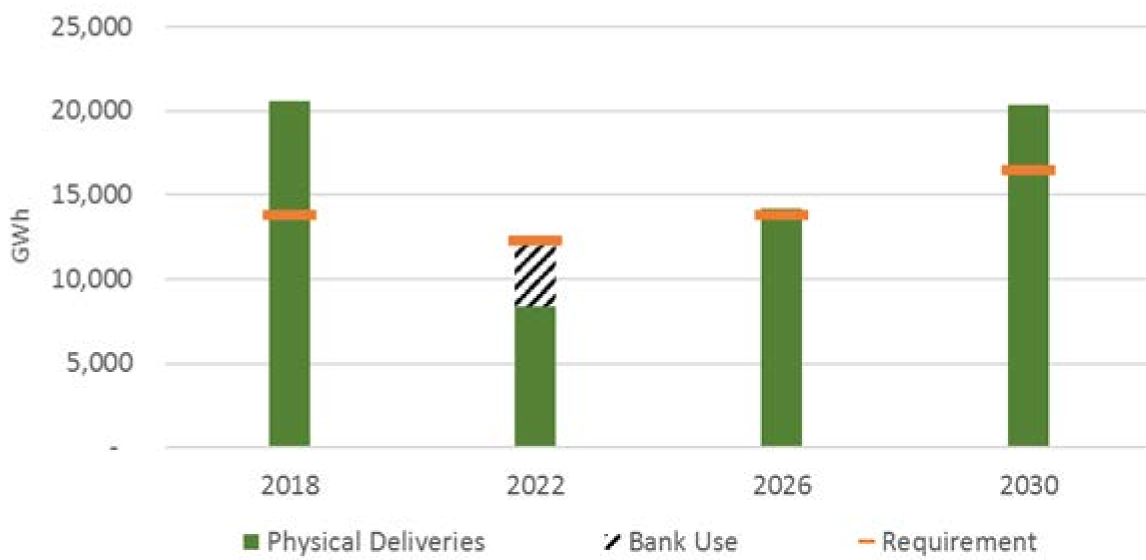
6) Greenhouse Gas Emissions

Based on the Alternative scenario load and mix of resources, PG&E's forecasted 2030 GHG emissions using the CNS methodology is 5.50 MMT. The benchmarks for the Alternate and Preferred scenarios are the same since both scenarios have the same amount of bundled load.

7) Renewable Portfolio Standard Compliance Position

Figure 9 and Table 27 show PG&E's RPS position under the Alternative scenario. The REC bank is used for compliance through 2023. Additional renewable deliveries are needed in 2024 for RPS compliance.[72]

FIGURE 9
ALTERNATIVE SCENARIO RENEWABLE COMPLIANCE POSITION



72 The bank usage and resulting need for new RPS deliveries here are shown for planning purposes only. They do not represent a determination of PG&E's RPS commercial procurement and banking strategy, which is detailed in PG&E's Annual RPS Procurement Plan Filings. If the Joint IOUs' GAM/PMM proposal is adopted by the Commission, PG&E's RPS sales will likely be impacted.

TABLE 27
ALTERNATIVE SCENARIO RENEWABLE COMPLIANCE POSITION

Line No.	Description	2018	2022	2026	2030
1	RPS Physical Deliveries (GWh)[(a)]	20,579	8,366	14,157	20,377
2	RPS Requirement (GWh)	13,816	12,300	13,821	16,494
3	Renewable Physical Net Short (GWh)	6,763	(3,934)	335	3,883
4	RPS Position (%)[(b)]	43.2%	36.5%	44.4%	60.3%
5	RPS Requirement (%)	29.0%	36.5%	43.3%	50.0%

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

(b) RPS position percentage is based on physical deliveries and the use of RPS bank.

8) System Resource Adequacy Position

Figure 10 shows PG&E's system RA position for the Alternative scenario. The position reflects PG&E's share of RA after CAM, GAM, and distribution resource allocations, and PMM RA auctions.[73] Due to GAM allocations and PMM auctions, PG&E needs to procure additional system RA starting in 2019. The RA procurement need will be met through market purchases from existing resources.[74]

73 2018 shows PG&E's RA position as of the November 2017 ERRA update to its 2018 forecast year. The 2018 position does not include sales made since fall 2017. For the Alternative scenario in years 2019 forward, PG&E assumes the non-bundled share of RA is either allocated (GAM) or auctioned (PMM).

74 As discussed above, 4-hour discharge batteries could also be considered to meet the RA need.

FIGURE 10
ALTERNATIVE SCENARIO SYSTEM RA POSITION
BASED ON AUGUST NET QUALIFYING CAPACITY

[redacted]

9) Key Prices

The prices used for the Alternative scenario are the same as those used in the Preferred scenario. PG&E used it's internally developed renewable technology cost forecast in the selection of additional resources needed in the Alternative scenario. The prices are provided in Tables 19 and 20 above.

D. Preferred Portfolio and Conforming Portfolio

PG&E developed its Preferred portfolio using its internal load forecast rather than the adjusted 2017 IEPR load forecast. In this period of rapidly shifting retail loads, it is critical that PG&E plan for the load it expects to serve in the future. This requires using PG&E's latest expectations of CCA growth, to ensure that PG&E does not plan for load it anticipates to depart bundled service in the future.[75] The Preferred portfolio also features higher electric vehicles levels that match PG&E's internal view of electric vehicle growth. These higher electric vehicle levels reflect both PG&E's strategic objective of facilitating clean fuel vehicle growth to two million vehicles in PG&E's service territory and furthering the Governor's goal of having five million zero-emission

75 PG&E's internal load forecast has stable volumes of Direct Access load over time, per existing policy that caps direct access. However, pending legislation as of July 10, 2018 (SB 237 (Hertzberg)) could reopen Direct Access.

vehicles statewide by 2030.[76] PG&E's internal forecast also features other changes to consumption, energy efficiency, and distributed generation, as explained in the Assumptions section of Section 2 (Study Design).

PG&E's Preferred portfolio meets PG&E's objectives of providing clean and reliable electricity to its customers at just and reasonable rates. This includes meeting the 2030 GHG emissions benchmark throughout the planning period as well as RPS compliance requirements. While the Preferred portfolio does not require any new procurement authority, it includes continued procurement of RPS and energy storage resources under existing CPUC programs and continued growth of distributed energy resources.

While it is PG&E's strong preference that the Commission adopt the Joint IOUs' GAM/PMM framework as proposed in the PCIA OIR, R.17-06-026, given that the Commission has not yet issued a decision in the PCIA OIR, it would be premature for PG&E to select the GAM/PMM Alternative scenario as its Preferred scenario and to develop a separate Action Plan for it. Therefore, PG&E has provided a GAM/PMM Alternative scenario as a sensitivity that demonstrates how PG&E's near-term resource needs would change if the proposal were adopted.

PG&E's Preferred portfolio meets the requirements of SB 350, as codified in Public Utilities Code section 454.52(a)(1):

- **454.52(a)(1)(A)**: "*Meet the greenhouse gas emissions reduction targets established by the State Air Resources Board, in coordination with the commission and the Energy Commission, for the electricity sector and each load-serving entity that reflect the electricity sector's percentage in achieving the economywide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030.*" PG&E's Preferred portfolio meets its LSE GHG planning target, and is contributing to reduced GHG emissions in another sector (transportation)
- **454.52(a)(1)(B)**: *"Procure at least 50 percent eligible renewable energy resources by December 31, 2030."* PG&E's Preferred portfolio meets its LSE RPS compliance target through 2030.
- **454.52(a)(1)(C)**: "*Enable each electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates.*" PG&E's Preferred portfolio meets the needs of its customers at just and reasonable rates; it includes procurement that has been approved by the Commission as reasonable. PG&E assumes some reform to the PCIA in this scenario, and has used the market-based inputs PG&E has advocated for in the PCIA OIR to forecast the PCIA market price benchmark.

[76] Executive Order B-48-18.

Thus, PG&E's average bundled service customer generation rates assume the PCIA cost shift has been reduced.

- **454.52(a)(1)(D): "***Minimize impacts on ratepayers' bills*." PG&E's Preferred portfolio minimizes ratepayer bills to the extent feasible through the IRP process. Specifically, it does not propose any incremental procurement given PG&E's lack of need through 2030. As described in both Section 4 (Action Plan) and Section 6 (Lessons Learned), PG&E supports the Commission including demand-side resources as candidate resources within future iterations of the IRP optimization. PG&E believes this can help California develop a truly optimal resource mix to meet the state's environmental goals and mitigate the current effects of the Net Energy Metering cost shift.
- **454.52(a)(1)(E):** "*Ensure system and local reliability.*" PG&E's Preferred scenario modeled its system and local resource adequacy needs and any RA market purchases needed to fill any open positions.
- **454.52(a)(1)(F)**: "*Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities.*" PG&E believes that its Preferred portfolio comports with this directive.
- **454.52(a)(1)(G):** "*Enhance distribution systems and demand-side energy management.*" PG&E's Preferred portfolio forecasts continuing growth in demand-side energy resources, including energy efficiency and rooftop solar generation. It also assumes continued adoption of demand response and behind-the-meter (BTM) energy storage technologies.
- **454.52(a)(1)(H)**: "*Minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities.*" PG&E's Preferred scenario includes an initial analysis to show how the growth of clean transportation technologies can help to address air pollution challenges in the state. It assumes the continuation of PG&E's low-income and DAC-focused economic assistance and clean energy programs.

Diablo Canyon Power Plant

In 2016, the Joint Parties to the DCPP Retirement Application announced, and sought CPUC approval for, a Joint Proposal to retire DCPP at the end of its current operating licenses, in 2024 and 2025.[77] In January 2018, the Commission approved the retirement of DCPP in D. 18-01-022.

77 A.16-08-006, filed on August 11, 2016. The members of the Joint Parties sponsoring the Petition for Modification are Friends of the Earth, the Natural Resources Defense Council, California Unions for Reliable Energy, and PG&E.

In February 2018, the Joint Parties filed a Petition for Modification to D.18-01-022 requesting that the Commission provide clear direction to all LSEs that it will expressly evaluate the adequacy of their specific resource plans in contributing to avoiding any increase in GHG emissions from the closure of DCPP, in addition to other enumerated requirements.[78] The Commission's recent IRP Amended Scoping Memo indicates that in August 2018, the Commission will "[issue a] proposed decision addressing petition for modification of D.18-02-018 related to Diablo Canyon closure."[79]

The Commission's Decision approving the retirement of DCPP ordered that:

- "Replacement procurement <u>will be addressed in the Integrated Resource Planning proceeding</u> or a proceeding designated by the Integrated Resource Planning proceeding."[80]
- "Efforts to avoid an increase in greenhouse gas emissions relating to the retirement of Diablo Canyon, including any replacement procurement, <u>will be addressed in the Integrated Resource Planning proceeding</u> or a proceeding designated by the Integrated Resource Planning proceeding."[81]

The first requirement has been fulfilled because replacement procurement has been addressed in the IRP proceeding. Specifically, the Commission's requirements for load serving entities filing IRPs concluded that: "[the RESOLVE results for the reference system plan shows that] rather than waiting until [DCPP] is retired (assuming that occurs), the model essentially chooses to pre-purchase the solar and wind power that would otherwise be needed later in the next decade, in order to take advantage of the cost savings associated with the ITC and PTC. In other words, the replacement power <u>in the amount of Diablo output is already being replaced by GHG-free resources prior to the retirement of the nuclear plant</u>. And in all scenarios, the GHG emissions constraints in the CAISO area are met or exceeded."[82]

The second requirement has also been fulfilled because the Commission's RSP analysis in the IRP indicates that, after DCPP Unit 1 retires in 2024 and Unit 2 retires in 2025, there are projected to be sufficient GHG-free resources online such that the GHG

---

78 Petition of Joint Parties for Modification of Decision 18-02-018, filed February 28, 2018, pp. 2, 9.

79 Rulemaking 16-02-007, Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, issued May 14, 2018.

80 D.18-01-022, OP 4 (emphasis added).

81 D.18-01-022, OP 5 (emphasis added).

82 D.18-02-018, p. 41 (emphasis added).

emissions target for the CAISO system would be met in each year through 2030.[83] Furthermore, the Commission's RSP projects GHG emissions CAISO-wide to be 37.2 MMT[84] during 2026 (the year after the retirement of Diablo Canyon Unit 2). This amount is well below 58.05 MMT,[85] the amount of CAISO-wide emissions estimated to have occurred CAISO-wide during 2016 (the year the Joint Parties applied to the Commission to retire DCPP).

PG&E encourages the Commission to validate the finding that the GHG emissions target for the CAISO system would be met in each year through 2030, during the analysis by Commission staff to aggregate Plans from all LSEs and create the Preferred System Plan.

Furthermore, in D. 18-01-022 approving the retirement of DCPP, the Commission ordered that PG&E "should be prepared to present scenarios for Diablo Canyon retirement in the Integrated Resource Planning proceeding that demonstrate no more than a *de minimis* increase in the GHG emissions of its electric portfolio."[86] This requirement has been fulfilled because PG&E's analyses for its Conforming and Preferred scenarios indicate 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 target for PG&E's bundled electric portfolio would be met in each year through 2030.[87] Furthermore, using the CNS Calculator provided by the Commission, PG&E calculated its bundled portfolio emissions for the Preferred portfolio during 2016 to be 10.4 MMT and during 2026 to be 4.4 MMT. These calculations demonstrate compliance with D. 18-01-022, OP 6.

PG&E's Alternative scenario is predicated on Commission approval of the GAM/PMM proposal as submitted by the Joint IOUs. Under PG&E's Alternative scenario, it is anticipated that PG&E would need to procure approximately 4,800 MW of GHG-free resources to meet RPS and GHG constraints. With the addition of these resources in

83 Results from CPUC's RESOLVE model reference system plan *42mmt_Ref_20170831*.

84 *Ibid.*

85 Greenhouse Gas Emissions Tracking Report – December 2017 https://www.caiso.com/Documents/GreenhouseGasEmissions-TrackingReport-Dec2017.pdf

86 D.18-01-022, OP 6.

87 PG&E calculated its yearly GHG target based on the ratio of PG&E's bundled sales to CAISO sales multiplied by the CPUC's CAISO system GHG benchmark for each year as shown in the RESOLVE model.

the timeframe envisioned by the Alternative scenario, PG&E would meet its GHG target in each year through 2030.

E. Local Air Pollutant Minimization and Disadvantaged Communities

In 2018, PG&E created a cross-functional team to develop a comprehensive approach to addressing energy needs across DACs in its territory. This effort reflects an explicit intention across the company to align resources, engage stakeholders, and develop a unified approach to better understand 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 and face a relatively high energy burden compared to other communities in PG&E's service territory. Additionally, the California Environmental Protection Agency (CalEPA) identifies these communities as having the highest percentile of adverse scores pertaining to poor environmental health and air quality.

The 2018 LSE IRP process adds a requirement for LSEs to consider air pollution and disadvantaged communities in their IRPs.[88] While the issues facing disadvantaged communities 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) may 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.

As stated throughout PG&E's 2018 IRP, PG&E anticipates providing electric service to less than 50 percent of its service territory load by 2030. However, for this inaugural IRP, 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, while recognizing that the company's role in advancing policies to support DACs in its service territory may evolve.

PG&E has two principles to address the current LSE fragmentation in California to ensure the state is effectively addressing DACs:

1. *All* LSEs must support DAC customers. Several non-investor owned utility (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.

[88] D.18-02-018, OP 6.

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.[89]

Below PG&E presents a summary of the DACs served in its service territory, its current activities/programs impacting these communities, a proposed approach to forecasting air pollutants using the CNS Calculator, and a discussion of how PG&E can help to further minimize air pollution. Since electricity generation only accounts for two to four percent of NOx emissions and one to two percent of $PM_{2.5}$ emissions in California, 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.[90] This strategy is necessary because the transportation sector emits 60-75 percent of the state's NOx and 12-22 percent of the PM.[91] PG&E also describes the number of PG&E-owned or contracted fossil power plants located in DACs. PG&E is not proposing to procure any new natural gas-fired power plants in this IRP and does not currently anticipate a need for future long-term contracts with facilities in DACs to meet its projected energy needs.[92]

1) PG&E's Disadvantaged Communities

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[93] within DACs, and key demographic information (see Table 28 below). For this analysis, PG&E used the definition of a DAC specified in

---

89 Note that the exception to this principle is when legislation or other regulatory requirements establish location-specific programs, such as San Joaquin Valley Disadvantaged Communities pilot described below.

90 CPUC RSP, Attachment A, slides 172-173.

91 *Ibid.*

92 Note that under the Commission's BioMAT Program, PG&E is required to execute power purchase agreements with certain resources that meet the program's eligibility requirements. PG&E expects to execute contracts with such resources, some of which may emit NOx and $PM_{2.5}$. Furthermore, some of the resources may be located in DACs.

93 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).

D.18-02-018.[94] Based on this definition, PG&E identified 443 census tracts within PG&E's electric service territory as DACs.[95]

TABLE 28
OVERALL PG&E AND DISADVANTAGED COMMUNITIES POPULATION IN PG&E ELECTRIC SERVICE TERRITORY

Line No.		Overall PG&E	Disadvantaged Communities	Percent of Overall PG&E
1	Residential Customers	4,419,945	609,103	14%
2	Business Customers	482,635	71,697	15%

Approximately 1 in 7 (14 percent) of the 4.4 million PG&E electric service territory residential customers live in designated DAC Census Tract Areas. Of these, almost three-quarters (72 percent) are located in the Central Valley region, despite the fact that the Central Valley region contains only approximately one-fifth of all residential customers in the PG&E electric service territory. 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, and 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 whitecollar 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 home owners, 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.

94 D.18-02-018, OP 6: "…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."

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

TABLE 29
REGIONAL DISTRIBUTION OF RESIDENTIAL CUSTOMER ACCOUNTS IN PG&E ELECTRIC TERRITORY[a]

Line No.	PG&E Region	# and % Overall PG&E Electric Service Territory Customer Accounts	# and % of PG&E Electric Service Territory Disadvantaged Community Census Tract Residential Customer Accounts
1	Bay Area Region	1,114,184 (25%)	100,815 (17%)
2	Central Coast Region	1,525,722 (34%)	49,145 (8%)
3	Central Valley Region	958,699 (21%)	440,407 (72%)
4	Northern Region	872,306 (20%)	19,079 (3%)

(a) 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 in across PG&E's electric service territory.

Of the 482,635 business customers in PG&E's electric service territory, 15 percent have businesses located in a DAC. These businesses are disproportionately high in the Central Valley region, with over half (62 percent) located in this area compared to only one fourth of all business accounts. The majority (54 percent) of these businesses have a tenure of 10 or more years, similar to all business accounts. Businesses in the DACs skew more towards small/medium businesses and less towards large businesses (based on their energy usage) compared to all businesses in the 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, or arts/entertainment/recreation industries.

TABLE 30
REGIONAL DISTRIBUTION OF BUSINESS ACCOUNTS[(a)]

Line No.	PG&E Region	% of Total PG&E Business Accounts	% of DAC Business Accounts
1	Bay Area Region	97,537 (20%)	11,728 (16%)
2	Central Coast Region	150,231 (31%)	12,456 (17%)
3	Central Valley Region	127,846 (26%)	44,634 (62%)
4	Northern Region	108,789 (23%)	3,106 (5%)

(a) 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) PG&E's DAC and Low Income Activities

PG&E actively addresses the challenges of DAC and low income communities by:

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:
   - San Joaquin Valley DAC OIR
   - Residential Rate Reform OIR
   - Energy Savings Assistance (ESA)/California for Alternate Rates (CARE) Low Income
   - Energy Efficiency
   - Electric Vehicle
   - Net Energy Metering 2.0
   - Electric Program Investment Charge
   - Green Tariff Shared Renewables
   - Demand Response
   - 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 California Alternate Rates for Energy (CARE) and Energy

Savings Assistance (ESA) meet critical bill assistance and energy efficiency needs, they may be limited in addressing other issues around energy options, environmental resilience, and climate change. PG&E will continue to seek creative ways to maximize customer participation in existing programs.

4. **Seeking new, innovative opportunities to better serve DACs**. Key examples are PG&E's proposed electrification and fuel switching pilots in the San Joaquin Valley and its collaborative approach to leveraging clean energy resources in the Oakland sub-area as a less costly alternative to building a new transmission line through Oakland.

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 an example, PG&E has started a Communities of Color Advisory Group Program to engage community based organizations and conduct outreach to diverse, hard-to-reach communities of color.

PG&E's collaborative DAC governance structure and support for serving DACs will ensure an inclusive and equitable approach for its customers.

In Appendix 4, PG&E describes the current programs, pilots, and investments aimed at customers in disadvantaged communities and low income customers, and indicates 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.

In addition to the programs, pilots, and investments included in Appendix 4, PG&E is participating in two innovative pilot projects in disadvantaged communities: the Oakland Clean Energy Initiative (OCEI) project and the San Joaquin Valley Disadvantaged Communities Project. These pilot projects are described in greater detail below.

<u>Oakland Clean Energy Initiative</u>

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 OCEI. This project will leverage clean energy resources in the CAISO's Oakland sub-area as a less costly alternative to building a new transmission line through the city of Oakland. This approach will utilize a portfolio of resources that may include energy efficiency, customer-sited energy storage and other distributed energy resources, along with utility-owned battery storage located at one or two of PG&E's substations, and some electric-system upgrades.

OCEI was approved by CAISO in March 2018, and a competitive solicitation was launched by PG&E in May 2018. PG&E expects to have a least-cost, best-fit portfolio of resources selected by early 2019 and operational by 2022. PG&E is conducting its solicitation in collaboration with a CCA, East Bay Community Energy (EBCE), which recently began selling electricity in Oakland and other communities in Alameda County. Besides the transmission dedicated battery storage at the substations, PG&E may contract with other resources to meet transmission reliability needs. EBCE may contract with the resources to provide capacity, energy and RECs. There may be some overlap in resources PG&E and EBCE choose thereby providing potential for cost-savings.

Once completed, this project will ensure clean, reliable electricity supply for the areas of the Oakland sub-area, which includes West Oakland and downtown Oakland, including many disadvantaged communities. Furthermore, it provides community residents and businesses the opportunity to contribute to the solution by implementing energy efficiency, energy storage and other distributed energy resources that will contribute to meeting local reliability needs.

PG&E has engaged a diverse group of stakeholders including the city of Oakland; the International Brotherhood of Electric Workers Local 1245; the Port of Oakland; environmental groups such as Environmental Defense Fund, West Oakland Environmental Indicators Project and Natural Resources Defense Council; and local businesses.

Given that the RFO is currently open and no projects have yet been submitted to the Commission for approval, PG&E's IRP modeling does not include any of the OCEI resources.

San Joaquin Valley Disadvantaged Communities

In 2015, the California Public Utilities Commission opened a Rulemaking (R.15-03-010) to identify disadvantaged communities in the San Joaquin Valley and to analyze economically feasible options to increase their access to affordable energy. In communities where natural gas is unavailable, wood stoves, propane or electricity are used for space and water heating. For low-income households, the use of natural gas or electricity can decrease utility costs, increase overall financial health, and provide a safer means of heating and cooling space and water. There are 170 identified DACs in the San Joaquin Valley and 131 of them are in PG&E's service territory.

PG&E is committed to supporting disadvantaged communities in the San Joaquin Valley and is exploring new, innovative ways to provide affordable energy options to these communities. PG&E has proposed two cost-effective pilots for customers who do not currently have natural gas service and who utilize some combination of electric, propane and/or wood burning services in their homes:

1) Electrification – provide community members with opportunities to switch their homes to an all-electric panel and appliance upgrades; and
2) Localized Gas System – build a local gas distribution network to serve customers currently on propane. Gas would be supplied through approximately 20 to 30 tube trailer deliveries per year to a central hub. PG&E proposes to supply the community with renewable natural gas through procurement or direct sourcing from nearby dairies or other biomethane sources.

PG&E proposes that customers will be eligible for new electric or gas appliances at no cost and receive all feasible energy efficiency measures for the home. Additionally, PG&E proposes that all San Joaquin DAC customers in the pilot communities who have electric service will also be eligible for increased savings through community solar. If approved by the Commission, this pilot would support a scientifically designed test of solutions to enable maximum learnings supported by a robust community engagement process that includes feedback from customers, CBOs, and local/elected officials.

3) Air Pollution Estimates

The Commission has directed LSEs to include in their respective IRPs the following information related to disadvantaged communities: "Detailed estimates of annual greenhouse gases and local air pollutants (including at least, nitrogen oxides and particulate matter), as well as annual starts of natural gas plants."[96]

This directive creates challenges for PG&E because a significant number of customers in certain DACs within PG&E's service territory do not receive electric service from PG&E – they receive service other LSEs including CCA, and DA providers. Nor are specific resources in PG&E's portfolio tied to a specific set of

96 D.18-02-018, OP 7.

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 customers.

Rather than develop estimates of local air pollutants in DACs that are attributable to PG&E, which is not possible, PG&E developed a methodology to provide more general estimates of criteria pollutants associated with PG&E's bundled service load, similar to the estimates of GHG emissions provided under PG&E's Conforming and Preferred portfolios. Annual estimates of the emissions, including emissions associated with gas plant starts, are presented in Appendix 2.

Applying the methodology described in Section 2 (Study Design), PG&E estimated NOx and $PM_{2.5}$ emissions associated with serving its bundled load under both its Conforming and Preferred scenarios in Table 31.

Air Pollution associated with PG&E's bundled portfolio, both dispatchable and non-dispatchable resources, is forecasted to decrease (NOx) or stay flat ($PM_{2.5}$) over the planning horizon due to: (1) changes in PG&E's load and supply portfolio, (2) decreased CHP emissions as units come off contracts,[97] and (3) changes in biogas/biomass emissions.

97 The non-dispatchable CHP forecast does not reflect qualifying facilities that may seek to extend their contracts with PG&E under PURPA.

TABLE 31
AIR POLLUTION EMISSIONS FORECAST
CONFORMING SCENARIO

Line No.		2018	2022	2026	2030
1	NOx (metric tons)				
2	CAISO Dispatchable Thermal Resources (CCGTs with emissions from starts, CTs and reciprocating engines)	16	(43)[a]	341	407
3	Combined Heat & Power (non-dispatchable)	3,358	1,462	718	316
4	Biogas	1,060	1,289	1,285	836
5	Biomass	886	961	829	755
6	Total NOx Emissions	5,320	3,669	3,173	2,314
7	PM2.5 (metric tons)				
8	CAISO Dispatchable Thermal Resources (CCGTs, CTs and reciprocating engines)	10	(26)	205	230
9	Combined Heat & Power (non-dispatchable)	109	48	23	10
10	Biogas	9	15	17	17
11	Biomass	538	520	473	417
12	Total PM2.5 Emissions	666	557	718	674

(a) PG&E's 2022 negative CNS position is driven primarily by (1) PG&E's reduced load and (2) excess GHG-free generation in PG&E's portfolio. This excess GHG-free energy, combined with hourly system GHG emissions factors, creates significant oversupply emissions credits, which drive PG&E's CNS GHG standing to a negative position.

TABLE 32
AIR POLLUTION EMISSIONS FORECAST
PREFERRED SCENARIO

Line No.		2018	2022	2026	2030
1	NOx (metric tons)				
2	CAISO Dispatchable Thermal Resources (CCGTs with emissions from starts, CTs and reciprocating engines)	16	(83)[(a)]	280	395
3	Combined Heat & Power (non-dispatchable)	3,358	1,462	718	316
4	Biogas	1,060	1,289	1,285	836
5	Biomass	886	961	829	755
6	Total NOx Emissions	5,320	3,629	3,112	2,302
7	PM2.5 (metric tons)				
8	CAISO Dispatchable Thermal Resources (CCGTs, CTs and reciprocating engines)	10	(50)	169	224
9	Combined Heat & Power (non-dispatchable)	109	48	23	10
10	Biogas	9	15	17	17
11	Biomass	538	520	473	417
12	Total PM2.5 Emissions	666	533	682	668

(a) PG&E's 2022 negative CNS position is driven primarily by (1) PG&E's reduced load and (2) excess GHG-free generation in PG&E's portfolio. This excess GHG-free energy, combined with hourly system GHG emissions factors, creates significant oversupply emissions credits, which drive PG&E's CNS GHG standing to a negative position.

It is important to note that the criteria pollutant emissions shown above do not reflect the emissions reductions from the transportation sector related to electrification of five million vehicles in California by 2030.

PG&E recognizes that its forecasting methodology has limitations, specifically: (1) it uses RESOLVE model generation and plant starts rather than more accurate production simulation modeling results; (2) it only accounts for start-up emissions from CCGTs, not from other plant types; (3) while the methodology utilizes PG&E's historical data for CCGT emissions, PG&E did not have data on other plant types to validate the emission factors developed by the Energy Division; and (4) the historical data used from PG&E's plants may not be representative of the CCGT resources throughout the CAISO. In developing this methodology, PG&E

determined that the lack of California-specific public emissions factors for NOx and $PM_{2.5}$, including emissions factors for plant cycling, is an impediment to LSEs' ability to accurately forecast air pollution emissions.

To address the limitations of PG&E's methodology and to further refine the air pollution forecasting methodology in the IRP proceeding, PG&E requests that Energy Division use its 2018 production simulation modeling in Strategic Energy Risk Valuation Model (SERVM) to validate the 12x24 emission factors PG&E developed for use in the CNS Calculator. This validation should include emissions from cycling of all plant types.[98]

The CNS methodology does a good job of allocating emissions to LSEs based on an hourly balance of supply and load *at a system level*. However, PG&E is not aware of a model that is capable of fairly allocating emissions by location at the DAC level. PG&E urges the Commission to carefully determine which LSE's load is responsible for the emissions for each of the plants in DACs. As discussed previously, facilities owned by or under contract to a given LSE may be dispatched by CAISO to meet the load of a different LSE. Care should be taken to assign responsibility *at a local or plant level* based on the customers for whom the energy is generated.

4) Minimizing Air Pollutants

PG&E has undertaken many efforts in the past to reduce air emissions in the state. As an example, PG&E had qualifying facility (QF) contracts with approximately 300 MW of coal and petroleum coke facilities. From 2011 through 2015, PG&E worked with these facilities to either terminate the contracts or, for two of the facilities, convert them to biomass resources. Currently, PG&E has no coal or petroleum coke facilities in its bundled electric portfolio, and believes there were emissions reductions associated with the facilities shutting down or converting to biomass.

PG&E has recently worked collaboratively to advance an innovative solution to cost-effectively meet a local reliability need while reducing emissions in the Oakland area. The OCEI project described above is anticipated to utilize a portfolio of resources that may include energy efficiency, customer-sited energy storage

98 Energy Division's May 25, 2017 IRP Reference Guide Question 22 notes that SERVM contains unit-level data for fuel burn per start for units throughout the CAISO. SERVM is expected to better represent the minimum generation characteristics associated with market operations that may lead plants to cycle less than assumed in RESOLVE.

and other distributed energy resources, along with utility-owned battery storage located at one or two of PG&E's substations. In this partnership model, PG&E is conducting its solicitation in collaboration with the CCA EBCE. There may be some overlap in the resources PG&E chooses to meet the local reliability need and the resources EBCE procures to meet capacity, energy, and REC needs, which would result in cost-savings to meet both PG&E and EBCE's needs and reduce emissions within the area. PG&E will continue to explore how the OCEI model can be replicated in DAC areas to identify cost effective alternatives to fossil resources.

Additionally, PG&E does not forecast adding any new natural gas fired resources to meet its projected energy or resource adequacy needs. 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 disadvantaged communities.[99]

PG&E has six non-CHP long-term contracts with fossil power plants located in disadvantaged communities; all but one of these contracts are set to expire by 2024 and PG&E does not currently anticipate a need for any future long-term contracts with these facilities to meet its projected energy needs. PG&E also has 12 long-term contracts with fossil CHP resources located in disadvantaged communities; all but one of these contracts are set to expire by 2022.[100] PG&E does not currently anticipate a need for future long-term contracts with soon-to-expire CHP resources.[101]

99 Note that all of PG&E's owned and contracted units are offered into the CAISO energy market using physical or contractual operating limits. This means that 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, as well as the subsequent air pollution emissions from these dispatched resources.

100 Includes contracts with CHP facilities executed by PG&E to meet MW and GHG emissions reduction targets authorized pursuant to the CHP Settlement Agreement, which established a CHP procurement framework through 2020 for each IOU.

101 PG&E recognizes that CHP procurement activities will be considered as part of the 2019-2020 IRP cycle per D.15-06-028, Finding of Fact 13 and 14; see also, Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, dated May 14, 2018, pp. 6-7. (NOTE: the plants in DACs described here do not include PURPA QFs.)

In its 2018-19 CAISO Transmission Planning Process, the CAISO has initiated a "Local Capacity Requirements Potential Reduction Study." The study will evaluate options for reducing Local Capacity Requirements using transmission upgrades or preferred resources. Addressing gas-fired generation located in disadvantaged communities is on CAISO's priority list for this study. PG&E strongly supports this effort and recommends the Commission work with the CAISO to determine if the power plants in the DAC areas could be replaced by a "green solution," such as renewable and battery storage projects. While PG&E recognizes that a detailed assessment is needed to ensure that these resources can be retired without impacting system reliability, PG&E is committed to working with the CPUC, the CAISO, and local communities to identify cost-effective alternatives to replacing fossil resources located in DAC areas.

California took an important step to address air pollution in the most heavily burdened communities through the passage of AB 617 in July 2017. AB 617 directs CARB to develop community air monitoring and community emissions reduction programs and to deploy them in the highest priority communities by July 2019. The monitoring programs will make use of new technology to provide more granular community exposure data from both stationary and mobile sources. The data will then be used to inform community-specific emission reduction strategies, creating a more targeted approach to addressing high exposure burdens. In addition, AB 617 updates air quality standards for certain stationary sources located in or contributing to non-attainment areas, provides for improved enforcement, and ensures community participation in the process. PG&E strongly supports a comprehensive, statewide air protection program and was actively engaged in the development and passage of AB 617. PG&E is working with CARB and other stakeholders through the AB 617 implementation process to ensure that the community air protection programs are successful and effective at reducing emissions in disadvantaged communities.

In an effort to achieve early action emission reductions in disadvantaged communities prior to AB 617 implementation, the Governor also signed AB 134 in 2017. AB 134 appropriates $250 million from the GHG Reduction Fund to the local air districts as one-time incentives to reduce mobile source emissions through the Carl Moyer Memorial Air Quality Standards Attainment Program and the Goods Movement Emission Reduction Program (Prop 1B). These programs target engine replacement, repower, and infrastructure in DAC and low-income areas in support of AB 617 goals. PG&E is working to collaborate with Bay Area Air Quality Management District and San Joaquin Valley Aire Pollution Control District to support Carl Moyer-eligible projects that will most effectively achieve emission reductions in those communities. In addition, PG&E has ordered four ultra-low

NOx natural gas trucks for its fleet to support mobile source emissions reduction through fuel switching.

PG&E believes that a comprehensive, multi-sector approach to addressing air pollution is required. Electricity generation accounts for only 2-4 percent of NOx emissions and 1-2 percent of $PM_{2.5}$ emissions in California, while the transportation sector contributes 60-75 percent of NOx emissions and 12-22 percent of $PM_{2.5}$ emissions in California. [102] Thus, any solution to address air pollution issues must include a focus on reducing transportation sector emissions. PG&E is committed to helping facilitate the growth of cleaner transportation options for its customers, as reflected in its Preferred scenario, which features two million EVs in PG&E's service territory by 2030. PG&E estimates that transportation electrification of two million light-duty EVs in its service territory by 2030 will avoid between 458-1,144 MT of NOx in 2030 and 229 MT of $PM_{2.5}$.[103]

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 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 electric vehicle could avoid between 3,812-7,623 grams of NOx and 1,143 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.[104] 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

102 CPUC RSP, Attachment A, slides 172-173.

103 Based on a national average 11,346 miles/year traveled (https://www.fhwa.dot.gov/policyinformation/statistics/2013/vm1.cfm), and emissions factors from California Air Resources Board's Low Emission Vehicles III emissions standards (https://www.arb.ca.gov/regact/2012/leviiighg2012/levfrorev.pdf), which lead to an avoided emissions range of 227-567 gNOx/vehicle/year and an estimated 113 gPM/vehicle/year.

104 Based on an estimated annual mileage of 19,058, and emissions factors from California Air Resources Board's LEVIII emissions standards (https://www.arb.ca.gov/regact/2012/leviiighg2012/levfrorev.pdf).

federal standard.[105] 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. PG&E plans 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.

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.

F. Cost and Rate Analysis

PG&E's Conforming portfolio and its Preferred portfolio revenue requirements and rates over the planning horizon are summarized in Tables 33 and 34 in nominal and real 2016 dollars. The rate presentation includes both the SADR containing the rate components recovered from all PG&E customers, and the SABR, which includes the SADR plus the bundled generation rate to determine the average rates for bundled customers. Rates are shown after applying the biannual GHG Climate Credit.

As described in the Section 2 (Study Design), the Conforming scenario relied on the Commission's planning assumptions to develop price assumptions used for market purchases or sales. PG&E's Preferred scenario relied on its own internal forecasts for commodity prices to better reflect PG&E's view of the future (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 utilized the forecasts already created for its 2017 IEPR filing.

PG&E notes that the rate forecasts provided in this filing are indicative. Actual realized rates will depend upon realized market prices, the outcomes of future rate cases, other ongoing proceedings, and market conditions. It is unclear at this time how each of the various changes in the long-term load forecast between the Conforming and Preferred scenarios (including changes to rooftop solar generation and clean transportation growth) will impact future revenue requirements. 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 (included 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).

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

Furthermore, as is the case with all rate forecasts, PG&E's future system and bundled sales will likely not exactly reflect what is being forecasted today.

The forecasted delivery rate revenue requirements (based on the 2017 IEPR) is presented net of GHG revenues and as such, the delivery rate changes slightly between the Conforming and Preferred scenarios due to the differences in the forward price assumptions for GHG compliance costs. In 2030, the Conforming scenario's delivery rate in 2016 dollars is 8.71 cents per KWh and in the Preferred scenario, the delivery rate in 2016 dollars is 7.97 cents per KWh. In terms of the generation resource portfolios, even though PG&E's bundled resource mix was unchanged between these scenarios, the generation revenue requirements are different between the scenarios due to: (1) differences in the forward market price assumptions, which impacts the dispatch of fossil resources and (2) the level of sales of RPS and RA resources, which is tied to differences in load assumptions. In 2030, the Conforming scenario's generation rate in 2016 dollars is 9.18 cents per kWh and in the Preferred scenario, the generation rate is 7.80 cents per kWh.

Changes to the system average bundled rates are driven primarily by changes to forecasted market prices and differences in the load forecast. The forecasted market prices also impact indifference amounts calculated for the PCIA revenues collected from departed load. Specifically, lower market prices in the Preferred scenario result in lower generation costs for bundled customers and higher recovery of above market costs from departing load customers. Those two factors, in combination with the fact that there is more departing load in the Preferred scenario all contribute to lowering the bundled customer generation revenue requirement, resulting in a lower generation rate.

TABLE 33

CONFORMING PORTFOLIO REVENUE REQUIREMENT AND RATE FORECAST

REVENUE REQUIREMENTS AND SYSTEM AVERAGE BUNDLED RATES FOR CONFORMING PORTFOLIO IN NOMINAL $

($MILLIONS)

Line No.	Cost Category	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Distribution	$4,707	$5,186	$5,238	$5,404	$5,326	$5,504	$5,672	$5,843	$6,018	$6,205	$6,398	$6,594	$6,795
2	Transmission	2,044	2,020	2,140	2,310	2,470	2,550	2,630	2,700	2,770	2,860	2,940	3,025	3,112
3	Generation	4,966	3,701	3,747	3,703	3,691	3,759	3,796	4,074	3,866	3,920	3,977	4,064	4,189
4	Demand Side Programs	443	621	620	620	621	621	621	621	434	434	434	434	434
5	Other (including GHG Credits)	412	383	120	70	(5)	(184)	(270)	(572)	(809)	(912)	(1,028)	(1,030)	(1,033)
6	Baseline Revenue Requirement	$12,572	$11,911	$11,864	$12,107	$12,102	$12,250	$12,449	$12,666	$12,278	$12,507	$12,721	$13,087	$13,497
7	System Sales (GWh)	80,774	82,145	82,147	81,900	81,946	81,683	81,337	81,257	80,973	80,732	80,442	80,214	80,016
8	Bundled Sales (GWh)	47,986	36,858	36,310	36,146	36,162	35,964	35,687	35,602	35,355	35,115	34,792	34,505	34,187
9	System Average Delivery Rate (¢/kWh)	9.42	9.99	9.88	10.26	10.26	10.39	10.64	10.57	10.39	10.64	10.87	11.25	11.63
10	Bundled Generation Rate (¢/kWh)	10.35	10.04	10.32	10.24	10.21	10.45	10.64	11.44	10.93	11.16	11.43	11.78	12.25
11	System Average Bundled Rate (¢/kWh)	19.76	20.04	20.20	20.51	20.47	20.85	21.27	22.02	21.32	21.80	22.30	23.03	23.89

TABLE 33
CONFORMING PORTFOLIO REVENUE REQUIREMENT AND RATE FORECAST
(CONTINUED)

REVENUE REQUIREMENTS AND SYSTEM AVERAGE BUNDLED RATES FOR CONFORMING PORTFOLIO IN 2016 $S
($MILLIONS)

Line No.	Cost Category	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Distribution	$4,507	$4,838	$4,768	$4,816	$4,657	$4,721	$4,771	$4,821	$4,871	$4,925	$4,980	$5,033	$5,088
2	Transmission	1,957	1,884	1,948	2,058	2,160	2,187	2,212	2,228	2,242	2,270	2,289	2,309	2,330
3	Generation	4,754	3,453	3,411	3,300	3,227	3,224	3,193	3,362	3,129	3,112	3,096	3,102	3,137
4	Demand Side Programs	424	580	564	553	543	532	522	512	351	344	338	331	325
5	Other	395	357	109	62	(5)	(158)	(227)	(472)	(655)	(724)	(800)	(786)	(773)
6	Baseline Revenue Requirement	$12,037	$11,112	$10,800	$10,789	$10,582	$10,507	$10,471	$10,451	$9,938	$9,928	$9,903	$9,990	$10,107
7	System Sales (GWh)	80,774	82,145	82,147	81,900	81,946	81,683	81,337	81,257	80,973	80,732	80,442	80,214	80,016
8	Bundled Sales (GWh)	47,986	36,858	36,310	36,146	36,162	35,964	35,687	35,602	35,355	35,115	34,792	34,505	34,187
9	System Average Delivery Rate (¢/kWh)	9.02	9.32	9.00	9.14	8.98	8.92	8.95	8.72	8.41	8.44	8.46	8.59	8.71
10	Bundled Generation Rate (¢/kWh)	9.91	9.37	9.39	9.13	8.92	8.96	8.95	9.44	8.85	8.86	8.90	8.99	9.18
11	System Average Bundled Rate (¢/kWh)	18.92	18.69	18.39	18.27	17.90	17.88	17.90	18.17	17.26	17.31	17.36	17.58	17.89

TABLE 34
PREFERRED PORTFOLIO REVENUE REQUIREMENT AND RATE FORECAST

REVENUE REQUIREMENTS AND SYSTEM AVERAGE BUNDLED RATES FOR PREFERRED PORTFOLIO IN NOMINAL $

($MILLIONS)

Line No.	Cost Category	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Distribution	$4,707	$5,186	$5,238	$5,404	$5,326	$5,504	$5,672	$5,843	$6,018	$6,205	$6,398	$6,594	$6,795
2	Transmission	2,044	2,020	2,140	2,310	2,470	2,550	2,630	2,700	2,770	2,860	2,940	3,025	3,112
3	Generation	4,966	3,453	3,397	3,311	3,197	3,181	3,196	3,378	3,179	3,231	3,304	3,404	3,519
4	Demand Side Programs	443	621	620	620	621	621	621	621	434	434	434	434	434
5	Other	412	410	185	139	66	(136)	(241)	(555)	(807)	(925)	(1,040)	(1,042)	(1,045)
6	Baseline Revenue Requirement	$12,572	$11,691	$11,579	$11,785	$11,680	$11,720	$11,878	$11,987	$11,595	$11,805	$12,036	$12,415	$12,816
7	System Sales (GWh)	80,774	81,371	[redacted]	[redacted]	81,489	81,551	81,796	82,412	83,197	84,054	85,035	86,130	87,291
8	Bundled Sales (GWh)	47,986	37,413	[redacted]	[redacted]	34,169	32,987	32,586	32,545	32,694	32,820	33,015	33,388	33,784
9	System Average Delivery Rate (¢/kWh)	9.42	10.12	[redacted]	[redacted]	10.41	10.47	10.61	10.45	10.12	10.20	10.27	10.46	10.65
10	Bundled Generation Rate (¢/kWh)	10.35	9.23	[redacted]	[redacted]	9.36	9.64	9.81	10.38	9.72	9.84	10.01	10.20	10.42
11	System Average Bundled Rate (¢/kWh)	19.76	19.35	19.48	19.78	19.77	20.11	20.42	20.83	19.84	20.04	20.28	20.66	21.07

TABLE 34
PREFERRED PORTFOLIO REVENUE REQUIREMENT AND RATE FORECAST
(CONTINUED)
REVENUE REQUIREMENTS AND SYSTEM AVERAGE BUNDLED RATES FOR PREFERRED PORTFOLIO IN 2016 $S

($MILLIONS)

Line No.	Cost Category	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Distribution	$4,507	$4,838	$4,768	$4,816	$4,657	$4,721	$4,771	$4,821	$4,871	$4,925	$4,980	$5,033	$5,088
2	Transmission	1,957	1,884	1,948	2,058	2,160	2,187	2,212	2,228	2,242	2,270	2,289	2,309	2,330
3	Generation	4,754	3,221	3,092	2,951	2,796	2,728	2,688	2,788	2,573	2,565	2,572	2,599	2,635
4	Demand Side Programs	424	580	564	553	543	532	522	512	351	344	338	331	325
5	Other	395	383	168	124	57	(116)	(203)	(458)	(653)	(734)	(809)	(795)	(782)
6	Baseline Revenue Requirement	$12,037	$10,906	$10,541	$10,502	$10,212	$10,052	$9,991	$9,891	$9,385	$9,370	$9,369	$9,477	$9,596
7	System Sales (GWh)	80,774	81,371	[redacted]	[redacted]	81,489	81,551	81,796	82,412	83,197	84,054	85,035	86,130	87,291
8	Bundled Sales (GWh)	47,986	37,413	[redacted]	[redacted]	34,169	32,987	32,586	32,545	32,694	32,820	33,015	33,388	33,784
9	System Average Delivery Rate (¢/kWh)	9.02	9.44	[redacted]	[redacted]	9.10	8.98	8.93	8.62	8.19	8.10	7.99	7.99	7.97
10	Bundled Generation Rate (¢/kWh)	9.91	8.61	[redacted]	[redacted]	8.18	8.27	8.25	8.57	7.87	7.81	7.79	7.78	7.80
11	System Average Bundled Rate (¢/kWh)	18.92	18.05	17.74	17.63	17.28	17.25	17.18	17.18	16.06	15.91	15.78	15.77	15.77

G. Deviations from Current Resource Plans

Any deviations from current resource plans are noted in the resource-specific tables in PG&E's IRP Action Plan (Section 4). Unless otherwise noted, PG&E's Preferred portfolio does not contain any major deviations from current resource plans.

H. Local Needs Analysis

The Commission's IRP decision required LSEs to report an assessment of how the LSE plans to meet its local resource adequacy requirement based on the CAISO's Local Capacity Technical Analysis reports for years 2018 and 2022 (from CAISO's 2017-2018 Transmission Plan). For both the Conforming and Preferred portfolios, PG&E is able to meet its local RA requirement (see Table 35 for the Conforming scenario and Table 36 for the Preferred scenario). The CAISO's Technical Analysis does not provide local requirement data for years beyond 2022.

TABLE 35
CONFORMING SCENARIO LOCAL NEED ANALYSIS RESULTS[a]

CPUC Bay Area Local RA Position (MW)
Long/(Short)

Line No.	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2018[b]									[redacted]			
2	2022	692	700	700	700	697	697	697	700	700	502	502	494

CPUC PG&E Other Local RA Position (MW)
Long/(Short)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
3	2018									[redacted]			
4	2022	1,335	1,532	1,533	1,533	1,532	1,533	1,533	1,532	1,532	1,532	1,209	1,014

(a) Positions as of 6/1/2018 (2018 not reflective of ERRA Forecast). Does not include transactions executed after 6/1/2018.

(b) Showing 2018 forecast starting for September 2018.

TABLE 36
PREFERRED SCENARIO LOCAL NEED ANALYSIS RESULTS[(a)]

CPUC Bay Area Local RA Position (MW)
Long/(Short)

Line No	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2018(b)									[redacted]			
2	2022	551	559	559	559	556	556	556	559	559	361	361	353

CPUC PG&E Other Local RA Position (MW)
Long/(Short)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
3	2018									[redacted]			
4	2022	1,202	1,398	1,400	1,400	1,399	1,400	1,400	1,399	1,398	1,398	1,075	880

(a) Positions as of 6/1/2018 (2018 not reflective of ERRA Forecast). Does not include transactions executed after 6/1/2018.

(b) Showing 2018 forecast starting in September 2018.

Extrapolation of CAISO's year 2022 requirement to year 2023, shows PG&E has an unmet local RA need starting in 2023. The CAISO indicated in its 2018-2019 transmission planning process that it is conducting a comprehensive look at each local capacity area and performing economic studies to identify potential transmission upgrades that would economically lower gas-fired generation capacity requirements in local capacity areas or sub-areas.[106] The CAISO will also target exploring and assessing alternatives (e.g., preferred resources) to reduce requirements in half of the existing areas and sub-areas. Although it is unclear today how these needs may be met in the future, PG&E has included additional cost starting in 2023 as a proxy for future local RA costs. The proxy is based on the local RA need identified in the CAISO 2022 LCR studies (extrapolated to 2023), and will be updated in future IRPs once the results for CAISO 2018-19 TPP are available for local capacity areas. [107]

106 http://www.caiso.com/Documents/Presentation-LocalCapacityRequirementReductionStudy.pdf.

107 PG&E did not include any assumptions about proposals under discussion now in Track 2 of the current RA OIR (R.17-09-020) on multi-year local RA requirements with a three-to-five-year duration or central buyer structures for multi-year local RA procurement.

4. Action Plan

Based on the study objectives, scenarios considered, and study results of PG&E's IRP analysis, this section presents PG&E's Action Plan to source the resources identified in its Conforming and Preferred scenarios. Nearly all of PG&E's near-term procurement activities are driven by existing state policy mandates and implementation of demand-side management programs. Due to past and expected future load loss to CCAs and PG&E's existing resource portfolio, PG&E has a near-term long position for energy, RA capacity, and RPS compliant resources in its Conforming and Preferred scenarios.

Regarding incremental procurement over the next 1-3 years, there is no difference in the Action Plan for PG&E's Conforming and Preferred scenarios since PG&E's bundled resource portfolio in both scenarios show no need for near-term procurement of additional RPS or GHG-free resources. Furthermore, PG&E's 2018 IRP only includes energy storage needed to meet: (1) existing procurement requirements (e.g., AB 2514, Resolution E-4909); or (2) other procurement proposals already made by PG&E (e.g., AB 2868). 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.

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). As described in Section 2 (Study Design), PG&E's Preferred scenario uses different long-term forecasts for load and load modifiers to account for increased penetration of electric vehicles, higher levels of EE, and lower levels of DG compared to the Conforming scenario. However, these differing assumptions do not lead to different near-term actions.

PG&E is not including a separate Action Plan for the Alternative scenario. This scenario results in the near-term need to procure new RPS resources, as presented in Chapter 3 (Study Results). If the Joint IOUs' GAM/PMM proposal is fully adopted by the Commission in R.17-06-026, PG&E will seek procurement authorization from the Commission for execution of additional RPS procurement prior to filing its next IRP. PG&E will seek a technology-neutral procurement process to select the least-cost best-fit resources to fulfill PG&E's RPS compliance requirements. Given that bid prices and market value will differ between the planning and procurement stages, PG&E may not end up procuring the specific levels of each RPS technology modeled in its Alternative portfolio.

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 Section 3 (Study Results) and in Appendix 4. PG&E will continue outreach activities to these communities as appropriate, even though in the future PG&E may not be the dominant energy supplier in central and northern California. 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 Action Plan presented in this section is organized by resource type; it describes for each resource type PG&E's existing near-term actions, key barriers, proposed new near-term actions consistent with Commission direction, deviations from current resource plans, and recommendations for how each resource should fit into future IRP cycles.

A. Renewable Energy

PG&E will continue to meet its RPS requirements as established by the California Legislature. Additionally, PG&E maintains its voluntary commitment, described in the Joint Proposal to the Diablo Canyon Power Plant Retirement Application, to meet a 55 percent RPS target starting in 2031. In both the Conforming and Preferred 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 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.

TABLE 37
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)] • Continue sales of RPS energy.
Key Barriers	• Load forecast uncertainty, including future CCA departure. • ncertainty regarding the PCIA OIR outcome.
Proposed New Near-Term Actions	• None at this time.
Deviations From Current Resource Plans	• No deviation from PG&E's near-term strategy in its Final 2017 RPS Plan. PG&E's forecasted RPS position differs slightly due to this IRP using a more recent PG&E bundled load and supply forecast vintage.
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) 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 v. 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 render ReMAT compliant with the Public Utility Regulatory Policies Act (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. PG&E will file a supplemental Tier 2 advice letter making minor modifications to the form BioMAT power purchase agreement to include high-hazard fuel requirements for projects that can attest to using 60 percent high-hazard fuel. Through BioMAT, PG&E expects to procure 111 MW of biomass resources by 2021.

- **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.
- **Continue Sales of Bundled RPS Volumes:** Pursuant to the Commission's approval of PG&E's 2017 RPS Procurement Plan, PG&E continues to consider opportunities for sales of RPS volumes that benefit its bundled customers. The approximately 2,000 GWh/yr of RPS sales assumed in this IRP is strictly a planning assumption and does not represent what PG&E will actually execute. 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 PG&E's RPS Strategy

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

- **Load Forecast Uncertainty, Including Future CCA Departure:** PG&E's RPS need is a function of its forecasted bundled 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 distributed generation and CCAs, 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 electric vehicle adoption, creates uncertainty with respect to PG&E's future RPS need. Based on PG&E's current view of its bundled load, PG&E has no incremental RPS procurement need in the Conforming and Preferred scenarios until after 2030.
- **Regulatory Uncertainty**: PG&E's RPS strategy is highly dependent upon the Commission's resolution of the PCIA OIR proceeding. If the CPUC adopts the Joint IOUs' GAM/PMM proposal, PG&E would dramatically reduce or eliminate further sales of its excess RPS resources and resume procurement of RPS resources in the near future.

Proposed New Near-Term Actions

PG&E will continue to address its long RPS position by engaging in efforts to sell RPS energy. PG&E is not seeking any new authority to procure RPS resources in this IRP. As noted elsewhere in this IRP, if the Commission adopts the Joint IOUs' GAM/PMM in the PCIA OIR, PG&E will seek procurement authorization from the Commission for execution of additional RPS procurement prior to filing its next IRP.

Recommendations for 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.

B. Energy Storage

PG&E is actively implementing California's programs to develop energy storage resources in the state to integrate renewable resources, provide output in periods of peak demand, and reduce greenhouse gas 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 38
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 • 2018 Local Sub Area Energy Storage RFO • Oakland Clean Energy Initiative
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).
Proposed New Near-Term Actions/ Commission Direction	• None at this time.
Deviations From Current Resource Plans	• PG&E's 2018 Energy Storage Procurement and Investments Plan covered only required procurement under AB 2514 and AB 2868. All storage procurement outside of or beyond those targets (such as the Local Sub Area RFO and the OCEI) was not included in that Application.
Recommendation for Future IRPs	• Continue modeling energy storage resources as candidate resources.

(a) PG&E's 2018 IRP only includes energy storage needed to meet: (1) existing procurement requirements (e.g., AB 2514, Resolution E-4909); or (2) other procurement proposals already made by PG&E (e.g., AB 2868). 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. Furthermore, given that the OCEI RFO is currently open and no projects have yet been submitted to the Commission for approval, PG&E's IRP modeling does not include any of the OCEI resources.

Existing Near-Term Actions

<u>AB 2514 Energy Storage RFOs</u>

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.[108] PG&E's proposal includes over 160 MW of energy storage investments on the distribution grid. Low-income and public-sector customers are the target customers for energy storage deployments for PG&E's Customer and Community Resiliency Investments category. The three remaining investment categories focus on deploying storage to meet specific grid needs, such as the increased load from new EV charging stations. As these specific sites are identified, there will be an opportunity for PG&E to prioritize deployments at sites that serve low-income communities. In addition to the 160 MW of energy storage investments, PG&E has also proposed an 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. If approved, the program would launch in 2020 and enroll 6,600 customers, who will benefit from energy bill savings and reduced onsite emissions from propane-based water heating.

2018 Local Sub Area Energy Storage RFO

In January 2018, the CPUC authorized PG&E to launch an accelerated solicitation for energy storage projects to contribute to reliability needs for three specified local sub-areas in the northern central valley and spanning Silicon Valley to the central coast (Pease, Bogue and South Bay – Moss Landing local sub-areas). PG&E issued its RFO in February 2018 and received offers from numerous participants. After careful evaluation, PG&E selected and submitted for approval four projects to be located within the South Bay – Moss Landing local sub-area: one offer for a 182.5 MW utility-owned project and three offers for 385 MW of third-party owned projects, which include a 10 MW aggregation of customer-sited storage.[109] Energy storage procured to meet the local sub area need will be used to meet PG&E's AB 2514 targets.

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 Oakland Clean Energy Initiative (OCEI). This project will leverage

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

109 Advice 5322-E, Energy Storage Contracts Resulting from PG&E's Local sub-area Request for Offers Per Resolution E-4909, submitted June 29, 2018.

clean energy resources in the Oakland sub-area as a less costly alternative to building a new transmission line through Oakland. This approach will utilize a portfolio of resources that may include energy efficiency, customer-sited energy storage and other distributed energy resources, along with utility-owned battery storage located at one or two of PG&E's substations. The project may also include certain electric-system upgrades. OCEI was approved by CAISO in March 2018, and a competitive solicitation was launched in May 2018. PG&E expects to have a least-cost, best-fit portfolio of resources selected by early 2019 and operational by 2022. PG&E is conducting its solicitation in collaboration with a Community Choice Aggregator (CCA), East Bay Community Energy (EBCE), which recently began selling electricity in the City of Oakland and other communities in Alameda County. Besides the transmission dedicated battery storage at the substations, PG&E may contract with other resources to meet transmission reliability needs. EBCE may contract with the resources to provide capacity, energy and RECs. There may be some overlap in the resources PG&E and EBCE choose, thereby providing potential for cost-savings. PG&E assumes energy storage procured to meet the OCEI need will be used to meet PG&E's AB 2514 targets, although given that the RFO is currently open and no projects have yet been submitted to the Commission for approval, PG&E's IRP modeling does not include any of the OCEI resources.

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.[110] 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 are 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

110 GTM Research. U.S. Front-of-the-Meter Energy Storage System Prices 2018-2022. February 2018. https://www.greentechmedia.com/research/report/us-front-of-the-meter-energy-storage-system-prices-2018-2022

markets, resource adequacy, 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. The work being undertaken through the MUA working group at the Commission and the Storage as a Transmission Asset initiative at CAISO 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 increases, 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 Multi-Use Applications

The adoption of rules by the CPUC to guide the formation of MUAs for energy storage has taken us 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.[111] The MUA working group discussed this issue, within the Ensuring Performance chapter, and recommended adopting "dispatch primacy" principle to clearly set the boundaries to maintain distribution reliability. Still, challenges remain to turn these principles and rules into real-world planning and operational processes and market design procedures that ensure distribution grid reliability. PG&E is actively engaged with utility and industry stakeholders in the MUA working group to better define how these rules would be implemented in the future.

[111] D.18-01-003.

Proposed New Near-Term Actions

PG&E will continue to procure energy storage needed to meet PG&E's 2018 IRP only includes energy storage needed to meet: (1) existing procurement requirements (e.g., AB 2514, Resolution E-4909); or (2) other procurement proposals already made by PG&E (e.g., AB 2868). 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.

<u>Deviations From Current Resource Plans</u>

The most comprehensive resource plan for energy storage in PG&E's territory is PG&E's 2018 Energy Storage Procurement and Investments Plan (filed March 1, 2018). However, this plan is only meant to encompass required procurement under AB 2514 and PG&E's proposal to implement AB 2868. All storage procurement outside of or beyond those targets was not included in that Application. For example, the results of the 2018 LSA ES RFO were filed separately on June 29, 2018.

Recommendation for 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, greenhouse gas 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.

C. Energy Efficiency

PG&E filed its 2018-2025 Energy Efficiency (EE) Business Plan ("Business Plan") on January 17, 2017 in compliance with D.15-10-028. In its Business Plan, PG&E describes its plans for achieving state policy goals such as those established by SB 350 and SB 32, which includes a smooth transition to third-party program design and delivery, and statewide administration of all upstream, midstream, and market transformation programs. In May 2018, D.18-05-041 approved PG&E's Business Plan, granting it authority to execute on the following key strategies:

- **Maximize Value of EE as a Grid Resource:** PG&E aims to further develop EE as a cost-effective grid resource that is integrated with other distributed energy resources, enabling deeper savings, greater penetration, and location-specific efficiency. This approach creates new opportunities for EE to be procured on a similar basis to supply-side resources and makes EE a more cost-competitive resource for use in areas like the Distribution Resources Plan.
- **Directly Influence Customers to Scale EE Beyond Widget-Based Incentives:** In the past, PG&E's EE portfolio relied on a widget-based incentive model driven by rebates and incentives for individual measures. Moving forward, PG&E is seeking to scale EE savings without significantly increasing its EE budget. This will require transitioning away from a traditional incentive-based model that results in thousands of dispersed transactions and towards new transaction structures, such as performance-based incentive structures, to spur greater customer and capital market investment in EE that more directly influence customers' decision-making processes.
- **Streamline PG&E's EE Portfolio and Make It Easier to Access:** In compliance with D.16-08-019, PG&E will be transitioning to a new program administration model where programs are proposed, designed, and implemented by third parties at the market sector level.[112] To facilitate this transition, PG&E intends to issue its first wave of solicitations for new programs in 2018, and will outsource at least 60 percent of its budget to third parties by the end of 2022. In addition, D.16-08-019 requires any current and future upstream, midstream, and market transformation programs to be administered on a statewide basis among the IOUs. PG&E believes statewide programs enable the IOUs to take advantage of uniform opportunities across the state and anticipates this model resulting in easier program access by customers and lower transaction costs.

---

[112] PG&E notes that CCAs can apply to administer EE funding. To date, MCE has applied for and received Commission approval to administer EE funds. Therefore, MCE and potentially other CCAs may also include an EE section in their Action Plan, which may be a subset of the results PG&E is providing.

TABLE 39
ENERGY EFFICIENCY – SUMMARY OF PG&E STUDY RESULTS, ACTIONS, AND RECOMMENDATIONS

Existing Near-Term Actions	• Offer a suite of loans, rebates, incentives, and technical assistance to customers to spur adoption of high efficiency equipment and technologies • Partner with retailers, distributors, and manufacturers to ensure EE solutions are designed, distributed, and stocked. • Deliver "cross-cutting" codes and standards, workforce education and training, and emerging technologies program.
Key Barriers	• Appropriate treatment and cost effectiveness calculation for programs not focused on resource acquisition. • New program models and approaches are needed to achieve energy savings at scale. • Effective coordination among a more diverse set of administrators and implementers.
Proposed New Near-Term Actions/ Commission Direction	• None at this time.
Deviations From Current Resource Plans	• PG&E's Preferred Portfolio is consistent with its 2018-2025 EE Business Plan.
Recommendation for Future IRPs	• Evaluate EE as a candidate resource in the IRP optimization.

Existing Near-Term Actions

PG&E currently supports EE adoption in its service territory through the following actions:

- **Offer a suite of loans, rebates, incentives, and technical assistance to customers to spur adoption of high efficiency equipment and technologies:** EE programs provide financial incentives to offset the higher up-front cost of efficient technologies or practices, enabling end-users to adopt energy efficient alternatives. More recently, programs have been exploring zero-interest or low-interest financing in lieu of traditional incentives, allowing programs to recoup the costs spent on reducing the up-front cost of EE.
- **Partner with retailers, distributors, and manufacturers to ensure EE solutions are designed, distributed, and stocked**: EE programs also engage market actors upstream of the customer to ensure that end-users have a robust set of energy efficient choices. Some programs encourage manufacturers to design and invest

in more efficient technologies, while other programs engage with distributors and retailers to stock, market, and sell those products.

- **Deliver "cross-cutting" codes and standards, workforce education and training, and emerging technologies programs:** While most of PG&E's EE programs are designed to meet the needs of specific market sectors (e.g., residential, commercial, industrial, agriculture, and public), PG&E also administers "cross-cutting" programs that support the entire portfolio of programs. For example, cross-cutting programs study and report on either emerging technologies to increase their adoption, or on more mature technologies to determine their readiness to be mandated in future codes or standards. Workforce education and training programs similarly seek to inform designers, contractors, and other energy professionals of both new and mature EE practices so that savings are pursued and realized in all programs.

Key Barriers to EE

<u>Appropriate Treatment and Cost Effectiveness Calculation for Programs Not Focused on Resource Acquisition</u>

The current cost-effectiveness protocols are not conducive to accelerating the adoption of new technologies, supporting persistency of savings, or supporting a broad array of state policy objectives: IOUs are directed to advance a diversity of objectives in addition to resource acquisition, such as serving disadvantaged customers, achieving deep savings, advancing market transformation, and training the workforce. Without valuation of these diverse objectives, the current cost-effectiveness framework limits IOUs' ability to achieve a cost-effective EE portfolio. Better aligning the cost-effectiveness framework with the broader goals of the EE portfolio would enable PG&E to provide robust support for California's long-term EE and IRP vision.

<u>New Program Models and Approaches Are Needed to Achieve Energy Savings at Scale</u>

California receives widespread recognition as an EE model due to its aggressive pursuit of EE since the 1970s. However, California's successful administration of EE programs and adoption of aggressive codes and standards has resulted in the reduction of "low-hanging fruit" opportunities that makes achieving greater energy savings cost-effectively an increasing challenge. New program models proposed by third parties and statewide programs present new opportunities to achieve greater energy savings at scale.

Effective Coordination Among a More Diverse Set of Administrators and Implementers

Since 2004, EE has for the most part been administered and delivered by the California IOUs. With recent changes enabling CCAs and Renewable Energy Networks to administer programs and substantial increases in third party program design and implementation, effective coordination among these various parties is essential to achieving EE savings in the most cost-effective manner.

Proposed New Near-Term Actions

PG&E will implement its EE Business Plan based on direction provided in D.18-05-041. PG&E does not seek any further Commission direction or changes to its EE budgets in this filing.

Recommendations for Future IRPs

Evaluate EE as a Candidate Resource in the IRP Optimization

In the 2017 RSP, EE was embedded as a load modifier, rather than a dynamic resource that could be optimized by RESOLVE at higher or lower levels based on the cost effectiveness relative to alternatives. This is a suboptimal approach that does not result in the least-cost portfolio to meet state goals. PG&E recommends including EE as a candidate resource in the 2019 IRP and allowing RESOLVE to identify an optimal EE level that would then form the basis for EE goals selected in the EE proceeding. This would also result in the IRP becoming the basis for EE's cost-effectiveness determination, which is consistent with SB 350's target of doubling EE, if cost-effective, and is consistent with the objective of establishing a Common Resource Valuation Methodology (CRVM) as part of the IRP that applies equally to demand and supply-side resources.

D. Demand Response

PG&E's strategy with respect to demand response (DR) is to establish DR as a technology neutral platform through which customers and aggregators can access markets and receive reasonable compensation for provision of necessary grid services. In addition, PG&E is expected to facilitate third-party provider programs bidding directly into the CAISO markets with access to customer-authorized data for CAISO registration, verification of customer eligibility and settlement processes for such programs.

PG&E will continue to implement its DR programs in compliance with D.17-12-003, which authorized program designs and funding levels for the period 2018-2022. In order to address the key barriers identified below, PG&E is engaging in a number of stakeholder working groups focused on addressing remaining barriers to DR market integration and developing new DR products that can cost-effectively meet grid needs. These stakeholder groups include the Supply Side Working Group that is focused on enhancing the current suite of market integrated products, the Load Shift Working Group that is focused on developing market integrated products that can address the need for flexible capacity and assist further in the integration of renewable generation, and the Energy Storage Multiple Use Applications working group (established on January 11, 2018 pursuant to D.18-01-003) that is looking at how BTM energy storage can serve both local and system needs related to both reliability, renewables integration, distribution, transmission services and customer self-services.

TABLE 40
DEMAND RESPONSE – SUMMARY OF PG&E STUDY RESULTS, ACTIONS, AND RECOMMENDATIONS

Existing Near-Term Actions[(a)]	• Work with regulators on programs that can participate in CAISO and CPUC DR markets. • Offer DR programs for residential and non-residential customers. • Pilot the demand response auction mechanism (DRAM) with third party demand response providers.
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. • Need for alternative rate designs. • Enrolling EV and other BTM battery storage in demand response programs for smart charging.
Proposed New Near-Term Actions/ Commission Direction	• None at this time.
Deviations From Current Resource Plans	• The demand response in PG&E's Preferred scenario is aligned with the current DR funding cycle budget (2018-2022) authorization per D. 17-12-003.
Recommendation for Future IRPs	• Develop and refine the supply curve for DR resources to be evaluated in the IRP optimization.

(a) Note that if a non-IOU LSE offers a DR program that the Commission deems to be "similar" to a PG&E DR program, the customers of that LSE will become ineligible to participate in the similar PG&E program and PG&E's DR numbers would be reduced.

Existing Near-Term Actions

Work With Regulators on Programs that can Participate in CAISO and CPUC DR Markets

PG&E is implementing DR programs in compliance with D.17-12-003 which authorized program designs and funding levels for the IOUs for the period 2018-2022. PG&E has recently finished integrating its Base Interruptible Program (BIP), Capacity Bidding Program (CBP) and Smart Air Conditioner Programs (SmartAC) into the CAISO markets and continues to assess and improve systems and processes that support market integration. 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 satisfied with their DR experience and that aggregators and third-party program providers are able to enroll eligible participants consistent with Commission guidance and applicable CAISO rules and procedures.

<u>Offer DR Programs for Residential and Non-Residential Customers</u>

PG&E's DR portfolio includes programs such as the Base Interruptible Program (BIP) and Peak Day Pricing (PDP) for non-residential customers, Smart Air Conditioner (SmartAC) and Smart Rate programs for residential customers and Capacity Bidding Program (CBP) and Time of Use (TOU) rates for all customer classes. Customers can enroll in PG&E DR program directly or through third-party aggregators. 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. Additionally, if a CCA or other non-PG&E energy service provider offers a DR program that is deemed by the Commission to be similar to a DR program offered by PG&E, then the customers whose energy is procured by the CCA or other non-PG&E energy service provider offering the similar DR program will be ineligible to participate in the similar program offered by PG&E.

<u>Pilot the DRAM With Third Party Demand Response Providers</u>

PG&E is piloting the demand response auction mechanism (DRAM) which is designed to encourage third party DR providers to develop demand response programs that are bid directly in the CAISO markets.

Key Barriers to Expansion of PG&E Demand Response Products

<u>Uncertainty With Respect to PG&E's Role as the Demand Response Provider (DRP) or Procurer</u>

CCAs are expected to serve an increasing portion of customers within the PG&E service territory over the coming years and there is a possibility that the DA cap will be reevaluated. Under the Competitive Neutrality Cost Causation principle, customers whose energy is procured by a CCA or an ESP are ineligible to participate in an IOU DR program if the CCA or ESP offer a program that is deemed by the Commission to be similar to the DR program offered by the IOU. The IOUs must end cost recovery from that provider's customers for any similar program and will file on August 10, 2018 proposed approaches to determine a bill credit. Reduction 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 included in the bill credit to the provider's customers.

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 which 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.

Need for alternative rate designs.

In order 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 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.

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.

A key element for expanding DR programs to cost-effectively meet grid needs is the enrollment of smart charging systems in DR programs. PG&E recommends that DR (with CAISO's Demand Response Provider Agreement rather CAISO's Distributed Energy Resource Provider Agreement) be used to enable BTM storage to participate in CAISO wholesale markets in order to become grid-response loads that serve the evolving needs of the grid.

Proposed New Near-Term Actions

None at this time.

Recommendations for Future IRPs

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.

E. Distributed Generation

PG&E's service area has more BTM solar PV interconnected than any utility in the United States.[113] 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. PG&E has also been active in developing best practices for incorporating DG into load planning and building codes and standards.

[113] Smart Electric Power Institute (SEPA) 2018 Annual Utility Survey.

TABLE 41
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 cost impacts of high penetration levels of BTM PV • Lack of systems and protocols to achieve full visibility, monitoring and value creation / realization for all stakeholders.
Proposed New Near-Term Actions	• Use IRP-based avoided cost values to inform future NEM tariff design.
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 and distributed generation. • Validate DG generation profiles against metered data.

(a) PG&E did not make any forecast assumptions about solar PV that may be built as a result of future distribution deferral opportunities. PG&E appreciates the efforts the CPUC is taking so that the 2020 LSE IRP cycle could include demand-side resources (including solar PV) as candidate resources within the IRP optimization, which may include including work being done to provide a methodology for calculating T&D avoided costs for a limited set of DERs in specific locations that could provide T&D benefits. The Commission should address not only distribution deferral opportunities, but also the cost of integrating solar PV.

Existing Near-Term Actions

As of the end of Q1 2018, PG&E had over 350,000 bundled and unbundled customers with DG installed behind the utility meter. PG&E is supporting these and future DG customers through a number of existing and planned actions.

Provide Customer Service Infrastructure to Implement Net Energy Metering Tariffs

Net Energy Metering (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, 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), 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. SGIP will accept applications through the end of 2020 under current program rules.
- The CSI Multifamily Affordable Solar Housing (MASH) Program, administered by PG&E in its service area. This program is no longer accepting applications. Incentives will, however, continue to be issued through 2021.
- The CSI Thermal program, administered by PG&E in its service area, which provides incentives for solar-thermal technologies. This program is expected to issue incentives through 2019.
- The CSI Single Family Affordable Solar Homes (SASH) administered by Grid Alternatives. PG&E supports the SASH program by reviewing final incentive packages and processing payments.
- The New Solar Homes Partnership (NSHP) program, administered by the California Energy Commission, provides incentives for solar on new residential construction. PG&E will be providing support to NSHP through 2020 by issuing incentive payments to the CEC.

In addition to the programs listed above, new DG incentive programs will be implemented over the next few years. As an example, PG&E will review and issue incentive payments for the Solar on Multifamily Affordable Housing (SOMAH) program, which will be administered by the Center for Sustainable Energy.

Streamline Interconnection and Facilitate Incorporation of Smart Inverter Technology

PG&E has devoted significant resources to improving processes to reduce interconnection times. PG&E is also making progress in 2018 to improve PG&E's Integration Capacity Analysis (ICA) resources available to DG installers, which will provide better visibility into locations where distributed generation may be more readily interconnected without significant grid infrastructure upgrades. To facilitate greater vendor understanding of interconnection processes and to receive feedback from vendors, PG&E has conducted contractor workshops for solar and other DG installers approximately twice a year. PG&E is actively participating in the Rule 21 Proceeding and Smart Inverter Working Group, 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;
- Actively participating in the CEC's IEPR Demand Forecasting process and sharing learnings with the CEC's Demand Analysis Working Group (DAWG) to improve statewide DG forecasting;[114]
- Constructively participating in the CPUC's Distribution Resources Plan Proceeding's "DER Growth Scenarios" working group 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
- Constructively participating in the NEM successor proceeding(s).

114 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.

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.

Key Barriers to Incorporation of DG Resources

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.

<u>Incentives Through the NEM Tariff Structure That Are Misaligned With DG's Net Value</u>

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.[115] This has resulted in DG adoption that is inconsistent with meeting system needs in the least cost manner, as demonstrated in the 2017 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, DG customers generally do not cover the cost to serve them and may, in fact, cost the utility more to serve than non-NEM customers. This puts 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.

<u>Lack of Visibility into DG Generation Data</u>

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

115 PG&E's Comments on Party Proposals and Staff Papers, September 1, 2015, NEM Successor Tariff, R.14-07-002 (hyperlink at: http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=351538).

as more DG, and particularly solar with variable generation, is incorporated into California's electrical system.

<u>Current Utility Operational Systems Are Not Yet Capable of Using Advanced Smart Inverter Technology to Its Fullest Extent</u>

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.

<u>Unknown Distribution Cost Impacts of High Penetration Levels of BTM PV</u>

Integration costs for rooftop solar are still unknown, especially at high penetration levels. As California moves towards the CEC's ZNE codes for new homes, housing developments will represent high concentrations of rooftop solar. The resulting integration issues associated with many residential circuits having high levels of solar installations are not well understood at this time.

<u>Lack of systems and protocols to achieve full visibility, monitoring and value creation / realization for all stakeholders.</u>

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 are measured by the utility revenue meter for customers participating in a NEM tariff. It is infeasible at this time 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.

Proposed New Near-Term Actions

Use IRP-Based Avoided Cost Values to Inform Future NEM Tariff Design

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. PG&E applauds the Commission's near-term commitment to re-examine NEM and suggests the Commission move swiftly to advance this discussion. 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.

Recommendations for Future IRPs

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 Distributed Generation

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. The CPUC can facilitate this by ensuring access to metered data as part of DG measurement and evaluation efforts, such as the CSI Final Impact Evaluation.

F. 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 climate and clean transportation goals. PG&E's Preferred portfolio includes expected deployment of 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. This adds additional load to PG&E's system sales compared to the 2017 IEPR. Without any adjustment to the electric sector and LSE GHG planning targets, these higher loads increase the effective stringency of the IRP and may create disincentives for transportation electrification, contrary to legislative and state agency intent. While we are not seeking adjustments to GHG planning targets in this inaugural IRP, we believe this is an important policy matter for state agencies to resolve in the next round of IRP given California's ambitions for electric vehicles. PG&E's proposed new near-term actions, most of which are already pending before, or are soon to be filed with, the Commission, will address key barriers to transportation electrification and electric vehicle adoption. Not only will PG&E continue to implement its existing CPUC approved infrastructure programs and offer EV-specific residential rates and rebates in the near term, but the utility will also look for new opportunities to support the needs of electric vehicle drivers, including customers located in disadvantaged communities, through additional program and rate design and through technology research and development.

TABLE 42
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.[a] • Support MDV/HDV charging infrastructure via SB 350 Priority Review Project pilots and PG&E's FleetReady Program.[a] • Expand charging options through PG&E's DC Fast Charging Infrastructure Program.[a] • Offer customers EV specific rates (e.g. EV-A and EV-B). • Offer customers clean fuel rebates.
Key Barriers	• Lack of availability of charging infrastructure. • Vehicle operating (fuel) costs. • Lack of EV awareness or understanding.
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 have been or will be filed in separate proceedings: • Approval of a new non-residential EV rate design.[b] • Authorization to expand infrastructure in state parks and schools (per AB 1082/1083).[b] • Approval of a new state-wide point of sale EV rebate program using LCFS funding. • Approval of the expansion of the EV Charge Network infrastructure program. • Approval of PG&E's "Empower EV" filing to test approaches to increasing EV adoption among low and moderate income customers.
Deviations from current resource plans	• N/A (activities conform with all PG&E's recent CPUC clean transportation related filings).
Recommendation for Future IRPs	• Consider increased levels of clean fuel vehicles. • Address inter-sector GHG accounting issues. • Explore the cost and benefits of EV charging flexibility.

____

(a) There were two pending EV program requests included in the distribution revenue requirement (RRQ) in PG&E's 2017 IEPR forecast: (1) $160.3 million associated with PG&E's Application for its "Charge Smart and Save" program (A.15-02-009), which was a pending settlement agreement at the time PG&E submitted its 2017 IEPR forecast; (2) $254.2 million for the FleetReady and DC Fast Charge program proposals and the Priority Review Projects pilot included in A.17-01-022. In this IRP, please note that beyond the two embedded EV assumptions described above, PG&E did not make any additional T&D RRQ assumptions associated with adding clean transportation infrastructure. PG&E may request additional grid investment funding in the future if it deems necessary to reliably accommodate additional EVs. Furthermore, PG&E did not make assumptions about the effect charging capacity factors may have on the utilization of clean transportation investments or how charging capacity factors may impact the system average bundled rate.

(b) To be filed after August 1, 2018.

Existing Near-Term Actions

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 7,500 level 2 EV charging stations at workplaces and multi-unit dwellings across Northern and Central California, installing 15-20 percent of the chargers in DACs.[116]
- **Support MDV/HDV Charging Infrastructure via SB 350 Priority Review Project Pilots and PG&E's FleetReady 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 information resource for residential EV drivers.[117] In addition, implement PG&E's FleetReady 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.[118] Additional incentives will be provided to DACs and school and transit buses.
- **Expand Charging Options through PG&E's DC Fast Charging Infrastructure Program:** Implement PG&E's Fast Charge Program by installing more than 50 plazas for DC fast charging in corridor and urban sites as well as provide incentives for locations in DACs.[119]
- **Offer Customers EV Specific Rates (e.g., EV-A and EV-B):** PG&E has two residential EV rates designed to promote EV charging during times consistent with grid needs, EV-A and EV-B.[120] 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. The rates further encourage weekend usage by removing the "partial-peak" time periods on Saturdays and Sundays.

116 D.16-12-065.

117 D.18-01-024.

118 D.18-05-040.

119 *Ibid.*

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

- **Offer Customers Clean Fuel Rebates:** PG&E will continue to administer the Clean Fuel Rebate funds provided by the State's Low Carbon Fuel Standard.[121] EV owners are rewarded for contributing to a cleaner energy future with their eligibility to receive a $500 Clean Fuel Rebate.

Key Barriers to Growing Clean Transportation

The actions PG&E is currently taking to promote clean transportation will facilitate achievement of California's clean transportation goals. However, PG&E's programs are not yet enough to ensure widespread adoption of clean transportation in all sectors and significant barriers to adoption remain to achieve the state's and PG&E's aggressive goals for expanding clean fuel vehicles. In the next 1-3 years, PG&E will target actions addressing the following barriers that were included in a list of critical barriers in PG&E's SB 350 Transportation Electrification testimony:

- **Lack of Availability of Charging Infrastructure:** In all vehicle types, costs of installing charging infrastructure can be significant and, in some cases, prohibitive.
- **Vehicle Operating (Fuel) Costs:** Light-duty vehicle charging can be cheaper than fossil fuel alternatives (especially when charged off-peak). However, medium- and heavy-duty EVs are often required to charge at higher power; resulting electricity costs, which include demand charges, may be higher than alternatives, especially when utilization of the charging asset is low.
- **Lack of EV Awareness or Understanding**: As with any new technology, drivers and fleet managers are simply unfamiliar with electric drive technologies, and experience with an EV is critical to dispelling any assumptions about their performance and operation.[122]

Proposed New Near-Term Actions

PG&E is planning to further address EV adoption barriers in the next 1-3 years and will request that the Commission address the following actions, which PG&E has filed or will file in separate proceedings:

- **Approval of a New Non-Residential EV Rate Design**: In 2018, PG&E plans to expand the availability of EV rates by filing a proposal for an additional EV rate targeting customers taking service under commercial rates.

---

121 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.

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

- **Authorization to Expand Infrastructure in State Parks and Schools (AB 1082/1083)**: PG&E is authorized to file an application to propose pilot programs to install EV charging stations at state parks and beaches, as well as at school facilities and educational institutions, under AB 1082 and AB 1083. The proposed pilots would install Level 2 charging at schools in select counties, and Level 2 and DC Fast Charging at select State Parks for visitors and for Park fleet vehicles.[123]
- **Approval of a New Statewide Point of Sale Rebate Program Using LCFS Funding:** In response to direction from the California Air Resources Board (CARB), PG&E is working with other utilities in California and automakers to create a statewide, point-of-sale EV rebate program. This program would be funded by the revenue from Low Carbon Fuel Standard (LCFS) credits that the utilities earn through the LCFS regulation for EV charging, and would replace the current, separate utility rebate programs from LCFS funds.
- **Approval of the Expansion of the EV Charge Network Infrastructure Program:** Prior to January 2020, PG&E will file an application for the second phase of PG&E's EV Charge Network light duty EV infrastructure program, according to CPUC direction.
- **Approval of PG&E's "Empower EV" Filing to Test Approaches to Increasing EV Adoption Among Low and Moderate Income Customers:** PG&E will test working with community based organizations to specifically market packaged EV incentives from a range of sources, including offering a rebate for a residential charger (and in some cases panel upgrade) to ascertain whether this approach can increase EV adoption among low and moderate income customers.

Recommendations for Future IRPs

<u>Consider Increased Levels of Clean Fuel Vehicles</u>

Future IRPs should consider increased levels of electric vehicles than were considered in the 2017 RSP. The Governor's goal of five million zero-emission vehicles statewide by 2030 should be considered in this IRP.

<u>Address Inter-Sector GHG Accounting Issues</u>

The state agencies should address inter-sector GHG accounting issues. The use of a single point target of 42 MMT and the resulting LSE targets in the CPUC's IRP process, without a mechanism to adjust for LSEs seeking to grow clean transportation beyond

123 To be filed after August 1, 2018 (the due date for LSE IRP filings).

the CPUC's assumptions, may produce a disincentive for LSEs to propose additional electrification efforts. An approach should be developed to either: (1) consider a GHG target range allowing for LSE flexibility for electrification, or (2) create a crediting mechanism due to electrification-driven GHG reduction in other sectors. Any approach should be coordinated with CARB's cap-and-trade program.

Explore the Cost and Benefits of EV Charging Flexibility

The benefits of EV charging flexibility should be further explored in future iterations of the IRP. Commission Staff's RSP analysis showed significant resource planning benefits associated with flexible EV charging.[124] 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.

124 See Commission's Energy Division presentation dated July 19, 2017, *Preliminary RESOLVE Modeling Results for Integrated Resource Planning at the CPUC*.

5. Data

The following templates shown in Table 43 were filed with the Commission as part of this testimony on August 1, 2018.

TABLE 43
TEMPLATES FILED AND ASSOCIATED FILE NAMES

Line No.	Description	File Name
1	Conforming scenario Baseline Resources Data Template	Data_PG+E_BaseRsrc_Conforming_20180801
2	Conforming scenario New Resources Data Template	Data_PG+E_NewRsrc_Conforming_20180801
3	Preferred scenario Baseline Resources Data Template	Data_PG+E_BaseRsrc_Preferred__20180801
4	Preferred scenario New Resources Data Template	Data_PG+E_NewRsrc_Alternative_20180801
5	Conforming Scenario CNS Calculator	CONFIDENTIAL_PG+E_Conforming_GHG Calculator for IRP v1.4.5_20180801
6	Preferred Scenario CNS Calculator	CONFIDENTIAL_PG+E_Preferred_GHG Calculator for IRP v1.4.5_20180801

1. <u>Conforming Scenario Baseline Resources Data Template</u>

Baseline Resources Tab includes information related to existing UOG resources and resources that PG&E has contracts with. These contracted resources are mostly existing resources but there are some resources that are not online yet. In addition, this tab includes the RPS and RA sales that PG&E included in its forecast. This tab does not include market purchases and/or sales needed to balance the portfolio.

In the Baseline Costs Tab the revenue requirement is shown for several categories including transmission, distribution and generation. The revenue requirement tab includes all revenue requirements needed for the calculation of system average rates, except for the revenue requirements for planned new resources for which PG&E does not have a contract. Consequently, this tab includes several additional cost items over and above the costs/revenues associated with the items shown in the Baseline Resources Tab. Additional costs shown under the generation line item include market purchases and sales to balance the portfolio, hedging costs, and CAISO costs. The generation line also includes non-by-passable charges collected from departing load associated with the resources shown in the Baseline Resources tab. In summary, the revenue requirements shown here can be added to the revenue requirements shown in the New Resources Data Template in the New Costs

Tab to calculate the total revenue requirements for bundled customers and system average bundled rates.

2. Conforming Scenario New Resources Data Template

The New Resources Tab includes information related to new resources in PG&E's forecast for this scenario and with which PG&E does not yet have contracts. As explained in earlier sections, in order to meet the GHG targets established in this proceeding, PG&E does not need to add any new resources to its portfolio over and above the mandated resources shown in Section 3, Table 8. Much of the resources shown in this table are under contract. However, a portion have not been contracted yet and those are the resources included in the New Resources Template. The costs associated with these resources are PG&E's internal cost forecasts and they reflect the recent prices PG&E has seen in the market. The rationale for using these costs as opposed to costs that are included in the RESOLVE model is that procurement to meet the mandates is not part of the IRP scope.

The New Costs Tab includes the revenue requirements for the resources shown in the New Resources Tab. The resources in this tab will not result in any incremental costs beyond incremental generation costs. Therefore, only the generation line has positive numbers. Because the system capacity expansion modeling performed by the CPUC using RESOLVE did not result in any new transmission, the incremental revenue requirements are also zero. Using similar logic, the distribution, demand side programs and other costs are also zero. However, the non-bypassable charge revenues are included in the generation revenue requirements line.

3. Preferred Scenario Baseline Resources Data Template

The information included in the Resources Tab is mostly the same as the information provided for the Conforming scenario described above. There are, however, two areas that are different. First, because of the different electricity and gas prices used for the Conforming and Preferred scenarios, the dispatch of fossil units is different. Second, because the load is different in the two scenarios, the RPS and RA sales are also different.

The content of the Baseline Costs Tab is the same as that for the Conforming scenario. The revenue requirements are different from those for the Conforming scenario mainly due to the different dispatch of fossil resources; different revenues from sales of RPS and RA resources; different open position levels due to different load; and different gas and electricity prices.

4. Preferred Scenario New Resources Data Template

   The information included in the New Costs Tab is identical to that presented for the Conforming scenario. This is because, as with the Conforming scenario, no new resources are needed to meet the GHG target over and above those needed to meet mandates.

   The New Resources Data Template also includes information related to PG&E's internal load forecast used for the Preferred scenario. These data are presented in the IEPR format in the several tabs of this template.

5. Conforming Scenario CNS Calculator

   CPUC's approved CNS Calculator adjusted for PG&E's Conforming Scenario.

6. Preferred Scenario CNS Calculator

   CPUC's approved CNS Calculator adjusted for PG&E's Preferred Scenario.

6. Lessons Learned

PG&E respectfully suggests for the Commission's consideration the following improvements to the IRP process on a going-forward basis.

A. CPUC's IRP Modeling and Process Alignment Activities

PG&E commends the Commission's efforts to initiate a new and innovative IRP process. Future cycles should consider further refinements to increase the benefits of integrated resource planning. PG&E recommends the following:

- **DERs should be incorporated into the IRP optimization process.** The 2017 RSP considered DER levels as discrete sensitivities, providing only directional information about optimal DER levels. This treatment is insufficient to meet the intent of SB 350. Future RSPs should include all demand-side resources as candidate resources within the optimization to ensure the RSP develops the truly optimal resource mix to meet the state's planning goals.
- **A Common Resource Valuation Methodology (CRVM) should be created and applied across Commission planning processes.** In D 18-02-018, the Commission created two separate GHG price signals: (1) a GHG Planning Price for IRP planning; and (2) a DER GHG Adder for DER valuation. Future IRP cycles should create one GHG planning price for all resource types in order to compare resources on an apples-to-apples basis and ensure fair treatment for all clean resource options. A CRVM should be developed and utilized to align other assumptions as appropriate (energy prices, generation capacity value, etc.).
- **The IRP RSP should be the basis for planning assumptions for all resource proceedings**. For most DERs, the 2017 IRP selected DER forecasts for the RSP in lieu of optimizing DER resources to determine an optimal level. Going forward, demand-side resource proceedings that establish resource acquisition goals, like EE and DR, should align these goals with the optimal resource level identified in the IRP. Similarly, the IRP optimization results should inform DER resources that depend on tariffs, like BTM solar PV. The RSP modeling results clearly showed that higher levels of BTM PV significantly increased overall costs.[125] These results should be subsequently applied to NEM policy adjustments in the next NEM proceeding. Additional clarity on the process to integrate this type of holistic planning perspective into Commission resource policy is needed.

---

125 CPUC RSP, Attachment A, slide 78 (hyperlink at: http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/AttachmentA.CPUC_IRP_Proposed_Ref_System_Plan_2017_09_18.pdf).

B. Inter-Agency Process Alignment Between the CPUC, CARB, CAISO, and the CEC

PG&E recognizes that this inaugural round of IRP is intended to be a "proof-of-concept" and that future IRP iterations will depend on improvements to interagency process alignment. PG&E specifically recommends the following improvements:

- **The agencies should improve coordination on electric sector GHG targets.** SB 350 dictates that CARB set electric sector and LSE-level GHG emissions planning targets, in coordination with the CPUC and CEC. In this proceeding, the CPUC has selected a 42 MMT statewide electric sector GHG emissions planning target for its jurisdictional LSEs and the CEC is using CARB's adopted statewide electric sector GHG planning target range of 30-53 MMT. PG&E believes establishing a GHG emissions planning target range is a useful approach to allowing flexibility in resource planning. Additionally, analytical results from the CPUC IRP process—such as the electric sector marginal GHG abatement cost—can provide helpful information to CARB when it considers future changes to the GHG planning target range.
- **The agencies should ensure implementation of GHG planning targets does not create disincentives to transportation electrification.** CARB's adopted electric sector GHG emissions planning target range of 30-53 MMT explicitly allows flexibility for load growth associated with electrification, whereby a small increase in electric sector emissions may be more than counterbalanced by significant emissions reductions from other sectors (e.g., transportation). In contrast, the CPUC's point planning target of 42 MMT, without a mechanism to adjust the planning target for GHG-reducing electrification, may provide disincentives for LSEs to pursue additional electrification efforts. Because SB 350 explicitly directed CARB to "remove regulatory disincentives" associated with achieving GHG reductions in other sectors through transportation electrification,[126] PG&E believes Commission's planning processes should be structured to do just that. Therefore, PG&E recommends the Commission either: (1) adopt a GHG emissions planning target range that allows flexibility for GHG-reducing electrification, such as the range adopted by CARB; or (2) create a mechanism to credit LSEs' GHG emissions planning target due to electrification-driven GHG reduction in other sectors. PG&E believes that meeting the state's goal of five million electric vehicles by 2030 would increase the current 42 MMT electric sector GHG target in the IRP by 1 to 2 MMT. While transportation electrification may require an increase to the GHG target of the electric sector, the increase will be more than

[126] Cal. Health & Safety Code section 44258.5(b).

offset by the avoided GHG emissions from the transportation sector in the range of 3 to 5 MMT on a lifecycle basis.

- **Consistent display of LSE GHG portfolios across state agencies.** PG&E applauds the CPUC for adopting a load-based, hourly approach to GHG emissions accounting for all LSEs (i.e., CNS methodology). PG&E encourages the CEC, CARB, and CPUC to work together to advance common alignment of GHG accounting in the direction of the CNS calculation, in particular as the CEC advances its rulemaking on AB 1110 to revisit requirements for the Power Source Disclosure framework. Without consistency across agencies on GHG emissions accounting, an illogical scenario may emerge in which many California LSEs claim to be GHG-free at the CEC, yet electric sector planning efforts at the CPUC show those same LSEs with non-zero emissions forecasts.
- **Efforts to consider economic retirements should be coordinated between the CPUC's IRP proceeding, the CPUC's RA proceeding, and the CAISO's Transmission Planning Process.** The 2017-2018 IRP cycle assumed no age-based or economic retirements of resources.[127] PG&E supports additional analysis in future IRP cycles to consider economic resource retirements and supports the Commission's directive to "work with the CAISO to study the most important attributes of the natural gas fleet and work in coordination with the resource adequacy proceeding activities."[128] PG&E also supports coordination with the CAISO to ensure reliability needs are met. In this IRP, PG&E's open RA position is assumed to be met with RA market purchases; however, PG&E notes that economic retirements of gas plants may drive future reliability needs and that energy storage resources may be an economic alternative to meet these needs. PG&E did not model additional local reliability or grid investment deferral opportunities that it expects to drive further storage additions in the future.
- **In coordination with the CAISO, future IRPs should include Local Capacity Need assessment in the development of the Reference System Plan.** Due to the unique nature of Local Capacity Areas (LCA) and the impact of potential retirements of existing gas fired units on local capacity need, it is important that the resource needs of LCAs are included in the development of the RSP. Since a local capacity need can be met by transmission or demand/supply side resources, co-ordination with the CAISO is crucial to ensure that the assumptions in the RSP are reasonable. It is also important that the candidate resources available for the development of the RSP include information on how the resources could mitigate the need for local area capacity.

127 Only once through cooling based retirements were assumed in the RESOLVE model.

128 D.18-02-018, p. 145.

C. LSE Plan Development Process

PG&E offers the following suggestions for improvement to the LSE Plan Development Process:

- **Alignment between the RSP inputs and those used for the Conforming LSE plans is required.** For this inaugural IRP, the Commission modeled the RSP using load and load modifier inputs based on the 2016 IEPR and CARB's Scoping Plan. LSEs, in contrast, were instructed to develop their Conforming plan using inputs from the 2017 IEPR, which reflected different load, load modifier levels (DG, EVs, etc.) and other assumptions. These inconsistent inputs result in an inherent disconnect between the RSP and the Conforming plans assembled by the LSEs.[129] For future IRP cycles the Commission should consider using the same vintage of inputs for the RSP and the LSE Conforming plan development by using the latest available data for both.

  The same vintage of the inputs should be used LSEs are mandated to use should align with the vintage of the required Conforming portfolio inputs.

- **LSE load forecasts, including CCA forecasts, should be updated in a timely manner in future IRP cycles.** The 2018 IRP LSE Plan development cycle began with the Commission approving use of the 2017 IEPR for the IRP but then also allowing existing and recently formed CCAs to update their load forecasts. While it is useful to incorporate the latest available information into the IRP process, the process to adopt use of these inputs should occur earlier in the planning process. The timing of the adoption of these critical inputs was insufficient to allow for robust analysis, sufficient vetting, and detailed documentation to meet an August 1 filing deadline; LSEs did not have their final conforming portfolio loads and GHG emissions benchmarks until mid-June. PG&E supports SCE's suggestion to use one regulatory process, such as the CEC's IEPR process, to standardize the load forecasts, including CCA forecasts, used in future IRP cycles.[130]

- **The IRP's Disadvantaged Communities requirements can benefit from additional standardization.** In the future, as retail load becomes increasingly fragmented

---

[129] For example, the rerun version of the Reference System Plan, using the 2017 IEPR, results in less solar PV and more geothermal than the Reference System Plan. It also outputs a significantly higher \$218/tCO2 GHG planning price compared to the \$150/tCO2 from the Reference System Plan.

[130] *Comments of Southern California Edison Company (U 338-E) on Community Choice Aggregators' Load Forecasts*, R.16-02-007, April 30, 2018.

through CCA and potentially ESP growth, the Commission should consider how to define LSE boundaries to ensure all LSEs are supporting the Commission's policy goals related to disadvantaged communities.

- **The Commission should work with stakeholders to develop a standardized framework for the evaluation of air pollutant emissions.** Since the Commission did not propose a methodology to forecast air pollutants, PG&E expects the Commission will receive emission estimates based on different methodologies and assumptions. In this IRP, PG&E used a CNS methodology to forecast system-level air pollution attributable to PG&E's bundled load. This methodology presents a coherent method to estimate system emissions for multiple emission types (GHG, NOx, $PM_{2.5}$) that result from an PG&E's hourly use of fossil generation to serve its load. However, for reasons discussed in Section 3 (Study Design), PG&E was unable to determine levels of air pollutants in DACs attributable to serving its bundled load.[131] PG&E encourages the Commission to work with stakeholders to develop for the next IRP a standardized framework that can be used by all LSEs to evaluate air pollutant emissions.

- **Rate forecast requirements should be standardized for all LSEs.** PG&E is soon expected to serve less than 50 percent of its service territory load. Consequently, it is unclear what actionable insights the Commission will gain from PG&E providing a forecast of its future rates. Regardless of PG&E's (or SCE and SDG&E's) load levels, in the competitive retail electric provider environment, the Commission should seek to either: (1) require all LSEs to provide a rate forecast; or (2) eliminate this requirement for the IOUs. The Commission should consider other forums, such as the new Affordability rulemaking, to explore the appropriate means for determining affordability for electric customers.

D. Lessons Learned From PG&E's IRP Analysis

- **Refinements should be made to the CNS Calculator to ensure accurate aggregate accounting for GHG at the CAISO level.** PG&E strongly supports the use of a CNS methodology to forecast LSE-level emissions in the IRP proceeding. While PG&E commends the Commission for adopting this approach, further refinements can be made. PG&E loaded the RESOLVE RSP inputs into the CPUC's CNS Calculator in order to benchmark the GHG accounting to the RESOLVE modeling results at the CAISO level. After this exercise, PG&E found improvements that can be made:

131 As noted in Section 3.E., PG&E is not able to forecast air pollution levels in disadvantaged communities attributable to serving its bundled load due to the fragmentation of LSEs in its service territory and other factors.

- The 2030 aggregate CAISO-level CNS MWh in the CNS Calculator should align with the total fossil + imports MWh from RESOLVE's RSP, given that the ultimate goal of the CNS methodology is to capture GHG emissions from all fossil generation and imports. This is not the case; the CAISO-level CNS Calculator underestimates the CNS position at 71,704 GWh, compared to the RSP's 2030 fossil/import generation of 81,448 GWh. This suggests that the CNS Calculator may not be capturing the full GHG burden used to serve CAISO load. PG&E believes this could be due in part to the overestimation of renewable generation in the CNS Calculator relative to the RSP results. The CNS Calculator uses 8,760 generation profiles from a single year (2007) for intermittent resources. This is not related to the profiles from RESOLVE's 37 days that were developed from years 2007-2009. This leads to a disconnect between RESOLVE's forecasted renewable generation and an LSE's generation when MWs of the LSE's contracts are input into the calculator. PG&E resolved this (for its own CNS calculation of GHG emissions) by adjusting its contracted capacity up or down to comport with its forecasted generation, but a closer alignment between the profiles—or flexibility to adjust based on LSE's contracted levels—is needed.
- The current CNS Calculator shows 0 tons/MWh emission factors throughout the middle of the day. However, at least in some months there are likely some fossil generators running at that time at minimum generation levels to support the evening ramp. Some calculation and allocation from minimum fossil generation emissions should be used. To exclude this could underestimate actual emissions.

PG&E thanks the Commission for leading the process to develop the inaugural IRP and looks forward to working with the Commission and other stakeholders to improve the IRP process going forward in order to further advance the goals envisioned by the California Legislature in SB 350.

Appendix 1:
Study Design
Bundled Portfolio Optimization Tool

The Bundled Portfolio Optimization Tool (BPOT) builds on the CNS framework by adding standard capacity expansion functionality. Like the CNS 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 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 Alternative scenario (GAM/PMM), the candidate resources were limited to those chosen at the system level by the RESOLVE model. Similarly, the model used the hourly price forecast developed for the Preferred and Alternative scenarios (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

Objective Function

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).

Constraints

- RPS: existing GHG -free + new RPS generation >= annual RPS target
- Resource Supply: Existing GHG-Free + New Resource generation + market purchases = bundled load

- GHG: 2030 (CNS-based) LSE emissions <= specified GHG planning target
- RA: Existing RA + New Resource RA+ Market Purchase >= 1.15%*bundled load

Other Key Inputs

- Nominal levelized cost of energy 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 CNS Calculator. For each year of the forecast, the following equations are specified for each hour:

CNS Emissions are calculated as:

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

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

Portfolio Costs are specified as:

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

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

RA is specified on a monthly basis as follows:

$$RA\ Requirement(MW) - Existing\ Resourc\ RA - New\ Resource\ RA\ (MW) = Market\ Purchase\ (MW)$$

RA Costs are specified as:

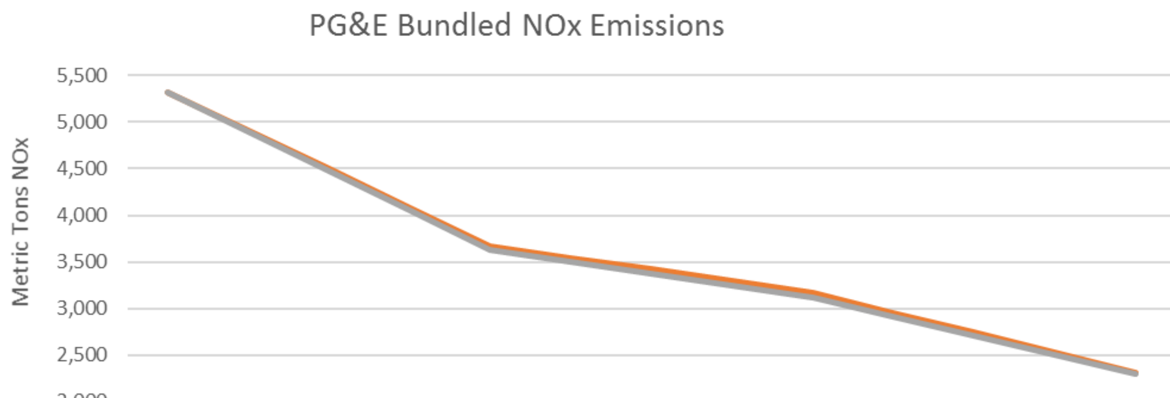
$$RA\ Costs\ (\$) = Market\ Purhase\ (MW) \times Market\ RA\ Price\ (\frac{\$}{kW\ month})$$

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

Appendix 2:
Study Results
Air Pollution Emissions

This Appendix includes PG&E's annual[132] NOx and $PM_{2.5}$ emissions results.

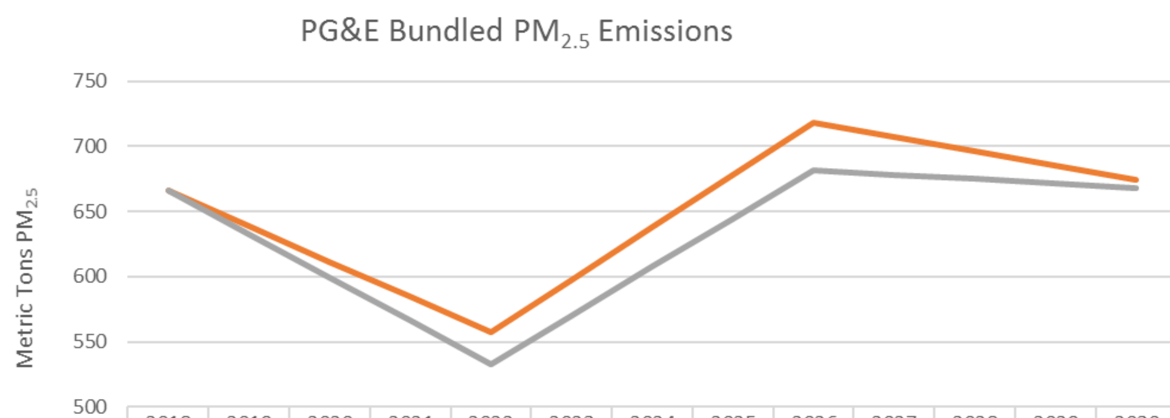
FIGURE 11
ANNUAL NOX EMISSIONS



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Conforming Scenario	5,320	4,907	4,495	4,082	3,669	3,545	3,421	3,297	3,172	2,958	2,743	2,528	2,314
Preferred Scenario	5,320	4,897	4,475	4,052	3,629	3,500	3,371	3,241	3,112	2,910	2,707	2,505	2,303

132 PG&E used the CNS Calculator modified to include air emissions from non-dispatchable CHP, biomass, and biogas resources to explicitly model each of the four years (2018, 2022, 2026, 2030) in the reference system plan and then linearly interpolated between these years to produce annual pollution estimates for the entire study period.

FIGURE 12
ANNUAL $PM_{2.5}$ EMISSIONS



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Conforming Scenario	666	639	612	584	557	598	638	678	718	707	696	685	674
Preferred Scenario	666	633	599	566	533	570	607	645	682	678	675	671	668

Appendix 3:
Study Results
Portfolio Results

TABLE 3-8: CONFORMING SCENARIO ENERGY SALES FORECAST (GWH)

Line No.	Description	2018 (a)	2019 (b)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	PG&E Gross System Usage	87,375	95,449	97,789	99,907	102,149	104,157	105,986	108,026	109,941	111,836	113,566	115,254	116,897
2	Energy Efficiency	(4,147)	(3,721)	(5,470)	(7,215)	(8,894)	(10,714)	(12,458)	(14,211)	(15,930)	(17,656)	(19,340)	(20,971)	(22,573)
3	Distributed Generation	(2,614)	(10,689)	(11,644)	(12,664)	(13,662)	(14,618)	(15,538)	(16,413)	(17,243)	(18,032)	(18,788)	(19,536)	(20,290)
4	Solar PV	(2,395)	(7,178)	(8,082)	(9,056)	(10,012)	(10,934)	(11,825)	(12,677)	(13,487)	(14,257)	(14,994)	(15,722)	(16,459)
5	Non-PV	(220)	(3,511)	(3,562)	(3,608)	(3,650)	(3,684)	(3,713)	(3,737)	(3,756)	(3,775)	(3,794)	(3,813)	(3,831)
6	Electric Vehicles	160	1,106	1,472	1,873	2,353	2,859	3,348	3,856	4,205	4,584	5,004	5,466	5,982
7	PG&E Net System Sales	**80,774**	**82,145**	**82,147**	**81,900**	**81,946**	**81,683**	**81,337**	**81,257**	**80,973**	**80,732**	**80,442**	**80,214**	**80,016**
8	Direct Access	(9,729)	(9,520)	(9,520)	(9,520)	(9,520)	(9,520)	(9,520)	(9,520)	(9,520)	(9,520)	(9,520)	(9,520)	(9,520)
9	Community Choice Aggregation	(23,060)	(35,767)	(36,316)	(36,234)	(36,264)	(36,198)	(36,130)	(36,135)	(36,099)	(36,098)	(36,130)	(36,188)	(36,309)
10	**PG&E Bundled Sales**	**47,986**	**36,858**	**36,310**	**36,146**	**36,162**	**35,964**	**35,687**	**35,602**	**35,355**	**35,115**	**34,792**	**34,505**	**34,187**

(a) The accounting for the load modifiers is different for 2018 as compared to the other years. For 2018 the Gross System Usage and load modifiers come from PG&E's 2018 ERRA Forecast (A.17-06-005) Table 2-3. For 2018, the load modifiers are incremental and only include amounts for 2017 and 2018. Modifiers for prior years are included in the Gross System Usage. In general, this results in a lower Gross System Usage and lower load modifiers for 2018 as compared to the other years.

(b) For 2019-2030, load modifier accounting treatment is as follows:

- Energy Efficiency values reflect cumulative incremental savings starting from a base year of 2018 (i.e., value at the start of 2018 is zero).
- Electric Vehicles values reflect cumulative totals (i.e., value at the start of 2019 reflects total adoption to that point).
- Solar PV values reflect cumulative totals (i.e., value at the start of 2019 reflects total adoption to that point).
- Non-PV DG values reflect cumulative totals incremental to 2001 (i.e., value at start of 2019 reflects total adoption since 2001).

TABLE 3-9: CONFORMING SCENARIO CUMULATIVE RESOURCE ADDITIONS (MW)

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Biogas													
2	SB1122/BioMAT	0	3	17	29	42	60	62	62	62	62	62	62	62
3	Biomass													
4	SB1122/BioMAT	0	0	14	20	32	44	47	47	47	47	47	47	47
5	SB32/ReMAT	0	0	0	0	0	2	10	22	34	46	50	50	50
6	**Subtotal (Biomas)**	0	0	14	20	32	46	57	69	81	93	97	97	97
7	Wind													
8	SB32/ReMAT	0	0	0	0	0	0	3	9	15	22	22	22	22
9	Solar PV													
10	SB32/ReMAT	5	5	5	6	14	23	32	41	44	44	44	44	44
11	GTSR	2	25	25	25	25	25	25	25	25	25	25	25	25
12	RPS (RFO)	170	342	452	452	452	452	452	452	452	452	452	452	452
13	RAM / PV RAM	20	19	33	110	110	110	110	110	110	110	110	110	110
14	**Subtotal (Solar PV)**	197	391	514	593	601	610	619	628	630	630	630	630	630
15	Storage (a)													
16	AB 2868/ Dist. Connected	[redacted]												
17	AB 2514/ IOU Target	0	0	20	70	95	175	175	175	175	175	175	175	175
18	Res. E-4909/ Local Deficiency	0	0	10	385	568	568	568	568	568	568	568	568	568
19	**Subtotal (Storage)**	[redacted]												
20	**Total Resource Additions**	[redacted]												

(a) Storage quantities do not include any storage procurement conducted as part of the Oakland Clean Energy Initiative.

TABLE 3-10: PG&E STORAGE ADDITIONS – NET OF CAM AND DISTRIBUTION ALLOCATION (MW)

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	AB 2868/ Dist. Connected	[redacted]												
2	AB 2514/ IOU Target	[redacted]				95	164	164	163	163	163	163	163	163
3	Res. E-4909/ Local Deficiency					255	246	241	239	237	235	233	232	231
4	Bundled Portfolio	[redacted]												

TABLE 3-11: CONFORMING SCENARIO TOTAL PORTFOLIO RESOURCES BY TECHNOLOGY (MW)

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Solar	4,048	4,217	4,341	4,420	4,427	4,436	4,445	4,454	4,457	4,457	4,457	4,447	4,447
2	Large Hydro (a)	[redacted]												
3	Nuclear	2,240	2,240	2,240	2,240	2,240	2,240	2,240	1,118	0	0	0	0	0
4	Wind	1,912	1,870	1,780	1,780	1,705	1,611	1,594	1,497	1,310	1,317	1,317	1,317	1,167
5	Storage	[redacted]												
6	Pumped Storage (Helms)													
7	Small Hydro	577	571	532	499	482	469	469	468	467	466	466	439	439
8	Biomass	301	274	288	248	260	211	222	234	246	258	217	217	217
9	Geothermal	272	272	272	272	22	22	22	22	22	22	22	22	22
10	Biogas	50	40	54	66	79	96	98	97	95	94	94	94	92
11	Natural Gas (CHP)	[redacted]												
12	Natural Gas (Non-CHP)													
13	**Total**	**19,778**	**19,802**	**19,598**	**19,176**	**18,651**	**17,673**	**15,997**	**14,669**	**13,366**	**13,102**	**13,062**	**13,026**	**12,475**

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

TABLE 3-12: CONFORMING SCENARIO ENERGY BALANCE (GWH)

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Energy Load													
2	PG&E Bundled Sales	47,986	36,858	36,310	36,146	36,162	35,964	35,687	35,602	35,355	35,115	34,792	34,505	34,187
3	Losses (T&D + UFE)	4,359	3,487	3,431	3,412	3,408	3,387	3,357	3,344	3,316	3,289	3,252	3,220	3,183
4	**Total Load Requirement**	**52,345**	**40,345**	**39,742**	**39,558**	**39,571**	**39,351**	**39,044**	**38,946**	**38,671**	**38,404**	**38,044**	**37,726**	**37,370**
5	Energy Supply													
6	**GHG Resources**													
7	Solar	9,167	10,050	10,161	10,391	10,451	10,418	10,406	10,350	10,298	10,245	10,213	10,122	10,065
8	Large Hydro (a)	[redacted]												
9	Nuclear	[redacted]								0	0	0	0	0
10	Wind	2,967	2,953	2,958	2,839	2,741	2,716	2,697	2,693	2,445	2,460	2,463	2,044	2,033
11	Storage (b)	[redacted]												
12	Small Hydro	1,965	1,864	1,773	1,678	1,609	1,586	1,590	1,580	1,580	1,578	1,580	1,528	1,520
13	Biomass	1,750	1,729	1,644	1,682	1,694	1,353	1,419	1,478	1,538	1,386	1,362	1,358	1,358
14	Geothermal	2,320	2,319	2,324	2,317	152	151	151	150	149	148	147	146	145
15	Biogass	273	255	326	420	497	560	559	553	548	542	544	531	529
16	CHP	[redacted]												
17	RPS Sales (c)	0	(3,179)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)
18	**Subtotal GHG-free and Non-dispatchable Resources**	[redacted]												
19	Other Resources													
20	Non-UOG Fossil	[redacted]												
21	UOG Fossil	[redacted]												
22	UOG Fuel Cell	[redacted]												
23	Wind (OOS)	939	754	745	743	727	478	256	208	0	0	0	0	0
24	Subtotal Other	[redacted]												
25	Market Sales / (Purchases)	[redacted]				7,704	8,487	7,144	(3,032)	(10,644)	(11,566)	(11,853)	(13,033)	(13,573)
26	**Total Energy Supply**	**52,345**	**40,345**	**39,742**	**39,558**	**39,571**	**39,351**	**39,044**	**38,946**	**38,671**	**38,404**	**38,044**	**37,726**	**37,370**

(a) Hydro generation reduction is driven by contract expirations and reduction in expected generation starting 2019 based on an updated historical 30-year average UOG hydro resources.
(b) Net energy from Helms pump storage resource. Energy impact from batteries not included since these resources are primarily capacity-only contracts. For any batteris where PG&E has rights to the energy, PG&E's market purchases will be reduced.
(c) RPS sales assumption is strictly for planning 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).

TABLE 3-13: CONFORMING SCENARIO RENEWABLE COMPLIANCE POSITION

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	RPS Physical Deliveries (GWh) (a)	20,579	17,775	18,730	18,700	16,416	15,837	15,672	15,619	15,183	14,970	14,906	14,324	14,230
2	RPS Requirement (GWh)	13,816	11,324	11,876	12,433	13,028	13,525	13,986	14,510	14,974	15,442	15,864	16,292	16,695
3	Renewable Physical Net Short (GWh)	6,763	6,451	6,854	6,266	3,388	2,312	1,686	1,109	209	(472)	(958)	(1,968)	(2,466)
4	RPS Position (%) (b)	43.2%	48.7%	52.0%	52.3%	46.0%	44.8%	44.8%	44.9%	43.9%	45.0%	46.7%	48.3%	50.0%
5	RPS Requirement (%)	29.0%	31.0%	33.0%	34.8%	36.5%	38.3%	40.0%	41.7%	43.3%	45.0%	46.7%	48.3%	50.0%

(a) RPS physical deliveries may be different than volumes shown in PG&E's annual RPS plan because of modeling and timing differences.
(b) RPS position percentage is based on physical deliveries and the use of RPS bank.

TABLE 3-14: CONFORMING SCENARIO COMMODITY PRICES ($ NOMINAL)

Line No.	Description	Unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	PGE Citygate	$/MMBtu	$ 3.23	$ 3.51	$ 3.65	$ 3.78	$ 3.91	$ 4.05	$ 4.19	$ 4.33	$ 4.52	$ 4.79	$ 4.93	$ 5.09	$ 5.26
2	GHG	$/MT	$ 15.38	$ 16.56	$ 18.91	$ 21.58	$ 24.63	$ 28.12	$ 32.09	$ 36.63	$ 41.82	$ 47.73	$ 54.49	$ 62.19	$ 70.99
3	On-Peak Energy Price	$/MWh	$ 36.73	$ 37.50	$ 34.24	$ 30.39	$ 31.43	$ 31.40	$ 32.63	$ 37.59	$ 40.46	$ 42.19	$ 42.40	$ 43.34	$ 44.83
4	Off-Peak Energy Price	$/MWh	$ 32.25	$ 32.50	$ 32.22	$ 31.80	$ 33.71	$ 35.42	$ 37.49	$ 43.27	$ 46.84	$ 48.84	$ 50.44	$ 52.85	$ 55.12
5	REC Price	$/MWh	$ 14.19	$ 31.69	$ 36.71	$ 41.75	$ 44.52	$ 47.86	$ 51.30	$ 58.06	$ 59.05	$ 60.33	$ 61.74	$ 63.21	$ 64.82
6	System RA Price	$/kw-year	$ 14.61	$ 26.15	$ 28.37	$ 29.81	$ 31.15	$ 32.08	$ 32.65	$ 31.88	$ 32.16	$ 34.79	$ 37.04	$ 41.53	$ 47.25

TABLE 3-15: CONFORMING SCENARIO COMMODITY PRICES ($ 2016)

Line No.	Description	Unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	PGE Citygate	$/MMBtu	$ 3.09	$ 3.28	$ 3.32	$ 3.37	$ 3.42	$ 3.47	$ 3.53	$ 3.57	$ 3.66	$ 3.81	$ 3.84	$ 3.89	$ 3.94
2	GHG	$/MT	$ 14.73	$ 15.45	$ 17.21	$ 19.23	$ 21.54	$ 24.12	$ 27.00	$ 30.23	$ 33.85	$ 37.89	$ 42.41	$ 47.47	$ 53.16
3	On-Peak Energy Price	$/MWh	$ 35.17	$ 34.98	$ 31.17	$ 27.08	$ 27.48	$ 26.93	$ 27.45	$ 31.02	$ 32.75	$ 33.49	$ 33.01	$ 33.08	$ 33.57
4	Off-Peak Energy Price	$/MWh	$ 30.88	$ 30.32	$ 29.33	$ 28.34	$ 29.48	$ 30.38	$ 31.54	$ 35.71	$ 37.91	$ 38.77	$ 39.26	$ 40.34	$ 41.27
5	REC Price	$/MWh	$ 13.59	$ 29.56	$ 33.42	$ 37.21	$ 38.93	$ 41.05	$ 43.15	$ 47.91	$ 47.79	$ 47.89	$ 48.06	$ 48.25	$ 48.54
6	System RA Price	$/kw-year	$ 13.99	$ 24.40	$ 25.82	$ 26.57	$ 27.24	$ 27.52	$ 27.46	$ 26.31	$ 26.03	$ 27.62	$ 28.83	$ 31.70	$ 35.38

TABLE 3-16: PREFERRED SCENARIO PG&E ENERGY SALES FORECAST (GWH)

Line No.	Description	2018 (a)	2019 (b)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	PG&E Gross System Usage	87,375	92,108	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Energy Efficiency	(4,147)	(4,155)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Distributed Generation	(2,614)	(7,522)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Solar PV	(2,395)	(5,880)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Non-PV	(220)	(1,641)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Electric Vehicles	160	939	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	**PG&E Net System Sales**	**80,774**	**81,371**	[redacted]	[redacted]	**81,489**	**81,551**	**81,796**	**82,412**	**83,197**	**84,054**	**85,035**	**86,130**	**87,291**
8	Direct Access	(9,729)	(10,051)	[redacted]	[redacted]	(10,051)	(10,051)	(10,051)	(10,051)	(10,051)	(10,051)	(10,051)	(10,051)	(10,051)
9	Community Choice Aggregati	(23,060)	(33,907)	[redacted]	[redacted]	(37,268)	(38,513)	(39,159)	(39,816)	(40,451)	(41,182)	(41,969)	(42,691)	(43,456)
10	**PG&E Bundled Sales**	**47,986**	**37,413**	[redacted]	[redacted]	**34,169**	**32,987**	**32,586**	**32,545**	**32,694**	**32,820**	**33,015**	**33,388**	**33,784**

(a) The accounting for the load modifiers is different for 2018 as compared to the other years. For 2018 the Gross System Usage and load modifiers come from PG&E's 2018 ERRA Forecast (A.17-06-005) Table 2-3. For 2018, the load modifiers are incremental and only include amounts for 2017 and 2018. Modifiers for prior years are included in the Gross System Usage. In general, this results in a lower Gross System Usage and lower load modifiers for 2018 as compared to the other years.

(b) For 2019-2030, load modifier accounting treatment is as follows:

- Energy Efficiency values reflect cumulative incremental savings starting from a base year of 2018 (i.e., value at the start of 2018 is zero).
- Electric Vehicles values reflect cumulative totals (i.e., value at the start of 2019 reflects total adoption to that point).
- Solar PV values reflect cumulative totals (i.e., value at the start of 2019 reflects total adoption to that point).
- Non-PV DG values reflect cumulative totals incremental to 2001 (i.e., value at start of 2019 reflects total adoption since 2001).

TABLE 3-17: PREFERRED SCENARIO ENERGY BALANCE (GWH)

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Energy Load													
2	PG&E Bundled Sales	47,986	37,413	[redacted]	[redacted]	34,169	32,987	32,586	32,545	32,694	32,820	33,015	33,388	33,784
3	Losses (T&D + UFE)	4,359	3,405	[redacted]	[redacted]	3,111	3,007	2,971	2,976	2,998	3,017	3,040	3,090	3,138
4	**Total Load Requirement**	52,345	40,817	[redacted]	[redacted]	37,281	35,993	35,556	35,521	35,692	35,837	36,055	36,478	36,922
5	Energy Supply													
6	**GHG Resources**													
7	Solar	9,167	10,050	10,161	10,391	10,451	10,418	10,406	10,350	10,298	10,245	10,213	10,122	10,065
8	Large Hydro (a)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0	0	0	0	0
10	Wind	2,967	2,953	2,958	2,839	2,741	2,716	2,697	2,693	2,445	2,460	2,463	2,044	2,033
11	Storage (b)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	Small Hydro	1,965	1,864	1,773	1,678	1,609	1,586	1,590	1,580	1,580	1,578	1,580	1,528	1,520
13	Biomass	1,750	1,729	1,644	1,682	1,694	1,353	1,419	1,478	1,538	1,386	1,362	1,358	1,358
14	Geothermal	2,320	2,319	2,324	2,317	152	151	151	150	149	148	147	146	145
15	Biogass	273	255	326	420	497	560	559	553	548	542	544	531	529
16	CHP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	RPS Sales (c)	0	(3,179)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)	(2,069)
18	**Subtotal GHG-free and Non-dispatchable Resources**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	Other Resources													
20	Non-UOG Fossil	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	UOG Fossil	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	UOG Fuel Cell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	Wind (OOS)	939	754	745	743	727	478	256	208	0	0	0	0	0
24	Subtotal Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	Market Sales / (Purchases)	[redacted]	[redacted]	[redacted]	[redacted]	10,747	12,559	11,488	1,380	(6,373)	(7,608)	(8,473)	(10,462)	(11,939)
26	Total Energy Supply	52,345	40,817	[redacted]	[redacted]	37,281	35,993	35,556	35,521	35,692	35,837	36,055	36,478	36,922

(a) Hydro generation reduction is driven by contract expirations and reduction in expected generation starting 2019 based on an updated historical 30-year average UOG hydro resources.
(b) Net energy from Helms pump storage resource. Energy impact from batteries not included since these resources are primarily capacity-only contracts. For any batteris where PG&E has rights to the energy, PG&E's market purchases will be reduced.
(c) RPS sales assumption is strictly for planning 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).

TABLE 3-18: PREFERRED SCENARIO RENEWABLE COMPLIANCE POSITION

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	RPS Physical Deliveries (GWh) (a)	20,579	17,775	18,730	18,700	16,416	15,837	15,672	15,619	15,183	14,970	14,906	14,324	14,230
2	RPS Requirement (GWh)	13,816	11,496	[redacted]	[redacted]	12,300	12,386	12,745	13,236	13,821	14,409	15,034	15,752	16,494
3	Renewable Physical Net Short (GWh)	6,763	6,279	[redacted]	[redacted]	4,115	3,451	2,927	2,383	1,361	561	(128)	(1,428)	(2,264)
4	RPS Position (%) (b)	43.2%	47.9%	[redacted]	[redacted]	48.7%	48.9%	49.2%	49.2%	47.6%	46.8%	46.7%	48.3%	50.0%
5	RPS Requirement (%)	29.0%	31.0%	33.0%	34.8%	36.5%	38.3%	40.0%	41.7%	43.3%	45.0%	46.7%	48.3%	50.0%

(a) RPS physical deliveries may be different than volumes shown in PG&E's annual RPS plan because of modeling and timing differences.
(b) RPS position percentage is based on physical deliveries and the use of RPS bank.

TABLE 3-19: PREFERRED SCENARIO COMMODITY PRICES ($ NOMINAL)

Line No.	Description	Unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	NG - PGE Citygate	$/MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	$ 3.20	$ 3.28	$ 3.37	$ 3.46	$ 3.53	$ 3.60	$ 3.67	$ 3.75	$ 3.82
2	GHG Allowance	$/MT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	On-Peak Energy Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Off-Peak Energy Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	REC Price	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	System RA Price	$/kw-year	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

TABLE 3-20: PREFERRED SCENARIO COMMODITY PRICES ($ 2016)

Line No.	Description	Unit	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	NG - PGE Citygate	$/MMBtu	[redacted]				$ 2.79	$ 2.81	$ 2.84	$ 2.86	$ 2.86	$ 2.86	$ 2.86	$ 2.86	$ 2.86
2	GHG Allowance	$/MT	[redacted]												
3	On-Peak Energy Price	$/MWh													
4	Off-Peak Energy Price	$/MWh													
5	REC Price	$/MWh													
6	System RA Price	$/kw-year													

TABLE 3-21: ALTERNATIVE SCENARIO RENEWABLE ENERGY CREDIT AND RESOURCE ADEQUACY AGGREGATE ALLOCATION TO DEPARTED LOAD

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	REC (GWh)	0	9,951	10,385	10,504	9,505	9,391	9,371	9,369	9,119	9,042	9,077	8,759	8,747
2	RA (NQC MW)	0	2,894	2,899	2,889	2,858	2,935	2,997	3,031	3,035	3,031	3,051	3,032	3,052

TABLE 3-22: ALTERNATIVE SCENARIO INCREMENTAL RESOURCE ADDITIONS (MW)

		Delivery Date							
Line No.	Description	2024	2025	2026	2027	2028	2029	2030	Total
1	New Solar	1,993	26	140	175	166	129	1,371	3,999
2	New Wind	250	73	0	77	55	267	101	822
3	Total	**2,243**	**99**	**140**	**251**	**221**	**396**	**1,472**	**4,821**
4	Cumulative Total	2,243	2,342	2,481	2,733	2,954	3,349	**4,821**	

TABLE 3-23: ALTERNATIVE SCENARIO TOTAL RESOURCE ADDITIONS (MW)

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Bioenergy	0	3	31	49	74	106	119	131	143	155	158	158	158
2	Wind	0	0	0	0	0	0	253	332	338	421	476	743	844
3	Solar PV	197	391	514	593	601	610	2,612	2,646	2,789	2,964	3,130	3,259	4,629
4	Storage	[redacted]												
5	**Total**	[redacted]												

TABLE 3-24: ALTERNATIVE SCENARIO CUMULATIVE RESOURCES BY TECHNOLOGY (MW)

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Solar	4,048	4,217	4,341	4,420	4,427	4,436	4,445	4,454	4,457	4,457	4,457	4,447	4,447
2	Incremental Solar (GAM)	0	0	0	0	0	0	1,993	2,019	2,158	2,333	2,500	2,628	3,999
3	Large Hydro (a)	[redacted]												
4	Nuclear	2,240	2,240	2,240	2,240	2,240	2,240	2,240	1,118	0	0	0	0	0
5	Wind	1,912	1,870	1,780	1,780	1,705	1,611	1,594	1,497	1,310	1,317	1,317	1,317	1,167
6	Incremental Wind (GAM)	0	0	0	0	0	0	250	323	323	400	454	721	822
7	Battery Storage	[redacted]												
8	Pumped Storage													
9	Small Hydro	577	571	532	499	482	469	469	468	467	466	466	439	439
10	Biomass	301	274	288	248	260	211	222	234	246	258	217	217	217
11	Geothermal	272	272	272	272	22	22	22	22	22	22	22	22	22
12	Biogas	50	40	54	66	79	96	98	97	95	94	94	94	92
13	Natural Gas (CHP)	[redacted]												
14	Natural Gas (Non-CHP)													
15	Total	**19,778**	**19,802**	**19,598**	**19,176**	**18,651**	**17,673**	**18,240**	**17,011**	**15,848**	**15,835**	**16,016**	**16,375**	**17,296**

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

TABLE 3-25: ALTERNATIVE SCENARIO CUMULATIBE RESOURCES BY TECHNOLOGY NET OF ALLOCATIONS AND SALES (MW)

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Solar	4,048	2,175	2,145	2,256	2,180	2,094	2,034	2,002	1,982	1,959	1,939	1,925	1,901
2	Incremental Solar (GAM)	0	0	0	0	0	0	1,993	2,019	2,158	2,333	2,500	2,628	3,999
3	Large Hydro	[redacted]												
4	Nuclear	2,240	1,086	1,057	1,038	1,003	964	936	460	0	0	0	0	0
5	Wind	1,912	934	910	814	787	715	663	653	604	597	591	528	522
6	Incremental Wind (GAM)	0	0	0	0	0	0	250	323	323	400	454	721	822
7	Battery Storage	[redacted]												
8	Pumped Storage													
9	Small Hydro	577	279	266	249	241	232	225	221	219	217	215	214	209
10	Biomass	301	140	153	150	145	160	155	152	150	128	126	125	122
11	Geothermal	272	141	137	135	11	10	10	10	10	10	10	10	10
12	Biogas	50	21	74	72	70	67	64	63	61	59	58	57	56
13	Natural Gas (CHP)	[redacted]												
14	Natural Gas (Non-CHP)													
15	**Total**	**19,778**	**10,764**	**10,539**	**9,869**	**9,106**	**7,751**	**9,317**	**8,847**	**8,303**	**8,472**	**8,637**	**8,784**	**10,195**

TABLE 3-26: ALTERNATIVE SCENARIO ENERGY BALANCE (GWH)

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Energy Load													
2	PG&E Bundled Sales	47,986	37,413	[redacted]	[redacted]	34,169	32,987	32,586	32,545	32,694	32,820	33,015	33,388	33,784
3	Losses (T&D + UFE)	4,359	3,405	[redacted]	[redacted]	3,111	3,007	2,971	2,976	2,998	3,017	3,040	3,090	3,138
4	**Total Load Requirement**	**52,345**	**40,817**	[redacted]	[redacted]	**37,281**	**35,993**	**35,556**	**35,521**	**35,692**	**35,837**	**36,055**	**36,478**	**36,922**
5	Energy Supply													
6	**GHG Resources**													
7	Solar	9,167	10,050	10,161	10,391	10,451	10,418	10,406	10,350	10,298	10,245	10,213	10,122	10,065
8	Incremental Solar	0	0	0	0	0	0	4,612	5,019	5,807	6,315	6,899	7,142	11,179
9	Large Hydro (a)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Nuclear	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0	0	0	0	0
11	Wind	2,967	2,953	2,958	2,839	2,741	2,716	2,697	2,693	2,445	2,460	2,463	2,044	2,033
12	Incremental Wind	0	0	0	0	0	0	714	714	714	714	909	1,136	2,290
13	Storage (b)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	Small Hydro	1,965	1,864	1,773	1,678	1,609	1,586	1,590	1,580	1,580	1,578	1,580	1,528	1,520
15	Biomass	1,750	1,729	1,644	1,682	1,694	1,353	1,419	1,478	1,538	1,386	1,362	1,358	1,358
16	Geothermal	2,320	2,319	2,324	2,317	152	151	151	150	149	148	147	146	145
17	Biogass	273	255	326	420	497	560	559	553	548	542	544	531	529
18	CHP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	RPS Sales (c)	0	(3,179)	(1,453)	(300)	0	0	0	0	0	0	0	0	0
20	GAM/PMM Energy Sales	0	(22,728)	(25,748)	(26,115)	(25,379)	(26,466)	(25,701)	(19,254)	(14,578)	(14,163)	(14,236)	(13,908)	(13,898)
21	**Subtotal GHG-free and Non-dispatchable Resources**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	Other Resources													
23	Non-UOG Fossil	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	UOG Fossil	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	UOG Fuel Cell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26	Wind (OOS)	939	754	745	743	727	478	256	208	0	0	0	0	0
27	**Subtotal Other**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28	Market Sales / (Purchases)	[redacted]	[redacted]	[redacted]	[redacted]	(12,563)	(11,838)	(6,818)	(10,072)	(12,361)	(12,673)	(12,833)	(14,023)	(10,300)
29	**Total Energy Supply**	**52,345**	**40,817**	[redacted]	[redacted]	**37,281**	**35,993**	**35,556**	**35,521**	**35,692**	**35,837**	**36,055**	**36,478**	**36,922**

(a) Hydro generation reduction is driven by contract expirations and reduction in expected generation starting 2019 based on an updated historical 30-year average UOG hydro resources.
(b) Net energy from Helms pump storage resource. Energy impact from batteries not included since these resources are primarily capacity-only contracts. For any batteris where PG&E has rights to the energy, PG&E's market purchases will be reduced.
(c) RPS sales assumption is strictly for planning 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).

TABLE 3-27: ALTERNATIVE SCENARIO RENEWABLE COMPLIANCE POSITION

Line No.	Description	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	RPS Physical Deliveries (GWh) (a)	20,579	9,973	9,547	9,565	8,366	7,871	13,034	13,571	14,157	14,769	15,418	16,126	20,377
2	RPS Requirement (GWh)	13,816	11,496	[redacted]		12,300	12,386	12,745	13,236	13,821	14,409	15,034	15,752	16,494
3	Renewable Physical Net Short (GWh)	6,763	(1,523)			(3,934)	(4,515)	0	336	335	360	384	374	3,883
4	RPS Position (%) (b)	43.2%	31.0%	[redacted]		36.5%	38.3%	40.9%	42.7%	44.4%	46.1%	47.9%	49.5%	60.3%
5	RPS Requirement (%)	29.0%	31.0%	33.0%	34.8%	36.5%	38.3%	40.0%	41.7%	43.3%	45.0%	46.7%	48.3%	50.0%

(a) RPS physical deliveries may be different than volumes shown in PG&E's annual RPS plan because of modeling and timing differences.
(b) RPS position percentage is based on physical deliveries and the use of RPS bank.

TABLE 3-28: CONFORMING SCENARIO SYSTEM RA (AUGUST NQC MW) - DETAIL FOR FIGURE 5

Line No.	Description	2018 (a)	2019 (b)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	RA Supply													
1	Natural Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	RPS-Eligible	2,513	2,590	2,544	2,428	2,194	2,191	2,190	2,190	2,162	2,077	2,077	2,032	2,030
3	Nuclear	2,280	2,280	2,280	2,280	2,280	2,280	2,280	1,140	0	0	0	0	0
4	Large Hydro	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Pumped Storage (Helms)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Non-Specified	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Outages	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	**Subtotal**	[redacted]	[redacted]	[redacted]	[redacted]	**11,918**	**10,678**	**10,270**	**9,135**	**7,973**	**7,611**	**7,608**	**7,180**	**7,177**
10	RA Requirement	[redacted]	(8,707)	(8,539)	(8,611)	(8,657)	(8,712)	(8,605)	(8,735)	(8,731)	(8,695)	(8,589)	(8,610)	(8,611)
11	Long / (Short) Position	[redacted]	[redacted]	[redacted]	[redacted]	3,261	1,966	1,665	400	(758)	(1,084)	(981)	(1,429)	(1,434)

(a) 2018 shows PG&E's RA position as of the November 2017 ERRA update to its 2018 forecast year. The 2018 position does not include sales made since fall 2017.
(b) PG&E's 2019 onward position incorporates executed RA sales for years 2019-2022 as of June 1, 2018. PG&E seeks to dispose of its long RA product positions consistent with the procurement processes and methods set forth in its BPP. There is no guarantee that PG&E's long RA products will be purchased by buyers.

TABLE 3-29: PREFERRED SCENARIO SYSTEM RA (AUGUST NQC MW) - DETAIL FOR FIGURE 8

Line No.	Description	2018 (a)	2019 (b)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	RA Supply													
1	Natural Gas	[redacted]												
2	RPS-Eligible	2,513	2,590	2,544	2,428	2,194	2,191	2,190	2,190	2,162	2,077	2,077	2,032	2,030
3	Nuclear	2,280	2,280	2,280	2,280	2,280	2,280	2,280	1,140	0	0	0	0	0
4	Large Hydro	[redacted]												
5	Pumped Storage (Helms)													
6	Storage													
7	Non-Specified													
8	Outages													
9														
10	Subtotal	[redacted]				**11,918**	**10,678**	**10,270**	**9,135**	**7,973**	**7,611**	**7,608**	**7,180**	**7,177**
11	RA Requirement	[redacted]				(8,449)	(8,099)	(7,870)	(7,791)	(7,761)	(7,700)	(7,661)	(7,671)	(7,682)
12	Long / (Short) Position	[redacted]				3,469	2,578	2,401	1,344	212	(89)	(53)	(491)	(505)

(a) 2018 shows PG&E's RA position as of the November 2017 ERRA update to its 2018 forecast year. The 2018 position does not include sales made since fall 2017.
(b) PG&E's 2019 onward position incorporates executed RA sales for years 2019-2022 as of June 1, 2018. PG&E seeks to dispose of its long RA product positions consistent with the procurement processes and methods set forth in its BPP. There is no guarantee that PG&E's long RA products will be purchased by buyers.

TABLE 3-30: ALTERNATIVE SCENARIO SYSTEM RA (AUGUST NQC MW) - DETAIL FOR FIGURE 10

Line No.	Description	2018 (a)	2019 (b)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	RA Supply													
1	Natural Gas	[redacted]												
2	RPS-Eligible	2,513	2,590	2,544	2,428	2,194	2,191	2,190	2,190	2,162	2,077	2,077	2,032	2,030
3	Incremental RPS-Eligible	0	0	0	0	0	0	174	156	160	189	212	295	357
4	Nuclear	2,280	2,280	2,280	2,280	2,280	2,280	2,280	1,140	0	0	0	0	0
5	Large Hydro	[redacted]												
6	Pumped Storage (Helms)													
7	Storage													
8	Non-Specified													
9	GAM Allocation & PMM Auction	0	(6,173)	(6,226)	(6,226)	(6,121)	(5,566)	(5,451)	(4,841)	(4,044)	(4,048)	(4,074)	(3,828)	(3,854)
10	Outages	[redacted]												
11	Subtotal	[redacted]				**5,962**	**5,112**	**4,993**	**4,450**	**4,088**	**3,753**	**3,745**	**3,647**	**3,680**
12	RA Requirement	[redacted]				(8,449)	(8,099)	(7,870)	(7,791)	(7,761)	(7,700)	(7,661)	(7,671)	(7,682)
13	Long / (Short) Position	[redacted]				(2,487)	(2,987)	(2,877)	(3,341)	(3,673)	(3,947)	(3,915)	(4,024)	(4,002)

(a) 2018 shows PG&E's RA position as of the November 2017 ERRA update to its 2018 forecast year. The 2018 position does not include sales made since fall 2017.
(b) For the Alternative scenario in years 2019 forward, PG&E assumes the non-bundled share of RA is either allocated (GAM) or auctioned (PMM).

Appendix 4:
Study Results
Disadvantaged Communities' Programs, Pilots, And Investments

In the tables below, PG&E describes the current programs, pilots, and investments it provides to customers in disadvantaged communities and to low income customers. 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.

As stated throughout PG&E's 2018 IRP, PG&E anticipates providing electric service to less than 50 percent of its service territory load by 2030. However, for this inaugural IRP, 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, while recognizing that the company's role in advancing policies to support DACs in its service territory may evolve.

DISADVANTAGED COMMUNITIES PROGRAMS, PILOTS, AND INVESTMENTS

	Category	DAC Programs and Pilots, and Investments	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
A	Clean Transportation	Fast Charge	D.18-05-040	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% of PG&E's 234 planned electric vehicle fast chargers will be located in DACs. PG&E will offer a significant rebate towards the purchase of fast chargers for customers based in these areas.		X	Distribution
B	Clean Transportation	FleetReady	D.18-05-040	PG&E will pay for and help customers install the electric infrastructure from the grid to the charging equipment at 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% 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 EV costs to DACs up to a program total of $10 million.		X	Distribution

	Category	DAC Programs and Pilots, and Investments	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
C	Clean Transportation	EV Charge Network	D.16-12-065	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 7,500 Level 2 EV chargers at condominiums, apartment buildings and workplaces across northern and central California, including 15-20% of the chargers at sites in disadvantaged communities.		X	Distribution
D	Demand Response	DR Pilot Projects to Benefit DACs	D.17-12-003	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. Note that under the current Competitive Neutrality Cost Causation framework customers whose energy is procured by a CCA or Energy Service Provider (ESP) are ineligible to participate in IOU DR programs if the CCA or ESP offers a similar DR program.		X	Distribution

	Category	DAC Programs and Pilots, and Investments	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
E	Renewable Natural Gas	SB 1383 Biomethane Projects	D.17-12-004	PG&E and other gas IOUs are obliged to interconnect biomethane projects located in their service territories per SB 1383. A proposed project that thoroughly explains, discusses, quantifies, and mitigates impacts and demonstrates outreach and engagement efforts in a DAC will receive higher scores.		X (gas customers)	Gas Transmission and Storage rate case
F	Solar and Community Renewables	Disadvantaged Communities – Single-Family Solar Homes	D.18-06-027	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.		X	GHG Allowance proceeds; when funds are exhausted, PPP
G	Solar and Community Renewables	DAC-Green Tariff	D.18-06-027	This program will provide a 20 percent bill discount to customers in disadvantaged communities who meet the income eligibility requirements for the California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs.	X		GHG Allowance proceeds; when funds are exhausted, PPP

	Category	DAC Programs and Pilots, and Investments	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
H	Solar and Community Renewables	Community Solar Green Tariff	D.18-06-027	This program will allow primarily low-income customers in disadvantaged communities who meet the income eligibility requirements for CARE and FERA to benefit from the development of solar generation projects located in or near their communities and receive a 20% 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.	X		GHG Allowance proceeds; when funds are exhausted, PPP
I	Storage	AB 2868 Front-of-the-Meter Storage Investments	D.17-04-039	PG&E has filed a proposal to the CPUC to deploy distributed energy storage in compliance with AB 2868. The proposal includes over 160 MW of energy storage investments on the distribution grid to enhance community resiliency and reliability, provide local capacity, and support EV charging stations. PG&E will prioritize deploying these projects within DACs.		X	Distribution

	Category	DAC Programs and Pilots, and Investments	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
J	Storage	AB 2868 Behind-the-Meter Thermal Energy Storage Program	D.17-04-039	PG&E has proposed 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 San Joaquin Valley OIR to electrify their water heating and shift that load to off-peak hours. If approved, the program would launch in 2020 and enroll 6,600 customers, who will benefit from energy bill savings. A portion of these customers will benefit from reduced onsite emissions from propane-based water heating.		X	PPP
K	Storage	Self-Generation Incentive Program (SGIP)	D.01-03-073 D.17-10-004	Provides rebates for qualifying distributed energy resource systems installed on the customer's side of the meter that provide electricity for all or part of the customer's load. The SGIP Equity budget requires that 25% of SGIP funds already allocated for energy storage projects will provide incentives for customer-sited energy storage projects in disadvantaged and low-income communities in California.		X	Distribution

	Category	DAC Programs and Pilots, and Investments	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
L	EE Service	Local Government Partnerships Program	D.18-05-041	PG&E's Local Government Partnership programs work with local governments to deliver energy services to city and county facilities and their communities. This includes turnkey installation and technical assistance for energy efficiency projects in disadvantaged communities for residential customers, small and medium businesses, and schools, among others.		X	PPP
M	Workforce Education & Training	Connections	D. 18-05-014	PG&E leverages its Workforce Education and Training (WE&T) efforts to support awareness of green careers in disadvantaged communities.		X	PPP
N	Workforce Education & Training	Career and Workforce Readiness Program	D.18-05-041	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 energy efficiency expertise and resources to enter the energy workforce.[a]		X	PPP

(a) 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.

INCOME QUALIFIED PROGRAMS, PILOTS, AND INVESTMENTS

	Category	Low Income Programs	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
A	Financial Assistance	California Alternate Rates for Energy (CARE)	D.17-12-009 D.17-05-013	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% of Federal Poverty Guidelines or someone in the customer's household is an active participant in other qualifying public assistance programs. In April 2018, 1,535,554 customers were eligible for the CARE Program and 1,390,287 were enrolled (90.5%).		X	PPP

	Category	Low Income Programs	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
B	Financial Assistance	Family Electric Rate Assistance (FERA)	Res. E-4808	The FERA Program provides a monthly 12% 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% 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 April 2018, 169,219 customers were eligible for the FERA Program and 26,230 were enrolled (16%).		X	Residential Distribution

	Category	Low Income Programs	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
C	Financial Assistance	Relief for Energy Assistance Through Community Help (REACH)	PG&E 30+ year partnership with the Salvation Army	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% 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. In 2017, REACH provided financial assistance to 6,000 households.		X	Shareholder and Charitable Contributions
D	Low-Income Proceeding	Energy Savings Assistance (ESA)	D.17-12-009 D.17-05-013	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 million customers.		X	PPP

	Category	Low Income Programs	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
E	EE Service	Residential Moderate Income Direct Install Program (MIDI)	D.18-05-041	MIDI serves residential customers with income below 400% of the poverty line with direct install measures focused on lighting, water usage, and HVAC. MIDI focuses on an underserved segment of customers with “moderate” income. Often MIDI serves ESA prospects who do not meet the ESA income requirements. MIDI operates independently of ESA and serves both single family and multifamily households.		X	PPP
F	EE Service	Mobile and Manufactured Homes Program	D. 18-05-041	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.		X	PPP

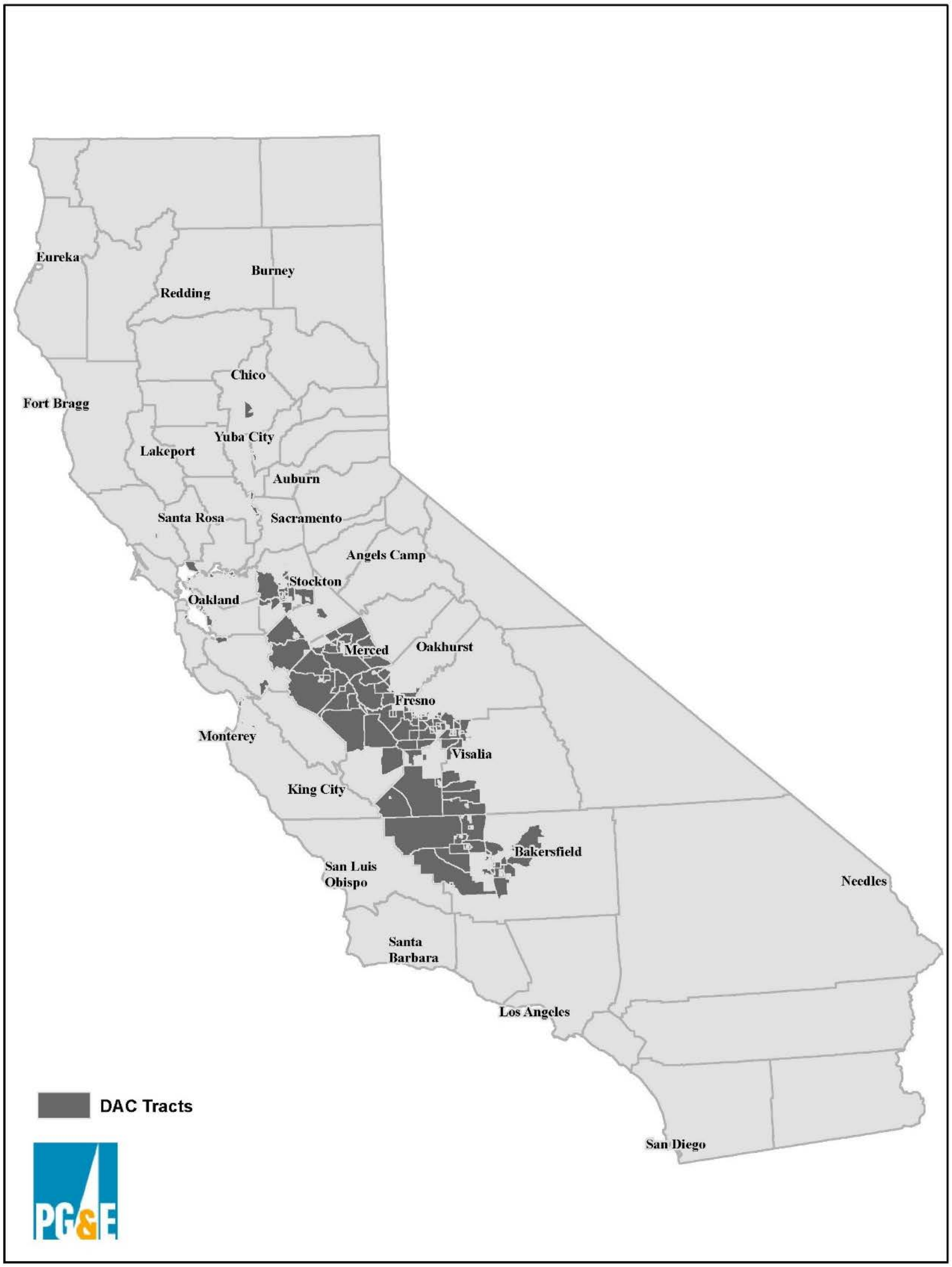
	Category	Low Income Programs	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
G	EE Service	Multifamily Energy Efficiency Programs	D. 18-05-041 D. 17-12-009	PG&E administers a suite of multifamily energy efficiency programs serving disadvantaged communities, such 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, distributed generation, rate options, and electric vehicles) for multifamily building owners		X	PPP
H	Education - EV	EV Educational Tools for DACs	D. 11-07-029 D.14-12-083 D.18-01-024	PG&E also offers electric rate plans tailored for EV customers and rebates for electric vehicle purchases. PG&E continues to launch more educational tools and resources to help our customers overcome barriers to adoption.		X	Distribution

	Category	Low Income Programs	Authority	Description	PG&E Bundled Customer Only	PG&E Service Territory Wide	Cost Recovery
I	Solar and Community Renewables	Multifamily Affordable Solar Housing (MASH)	D.15-01-027	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.		X	Distribution
J	Solar and Community Renewables	Single Family Affordable Solar Homes (SASH)	D.17-05-013	Provides solar incentives on qualifying affordable single-family housing.		X	Distribution

Appendix 5:
Study Results
Disadvantaged Communities Service Territory Map

In the map below, PG&E displays the DACs in its service territory that correspond to the definition in the CPUC’s D.18-02-018:

“A disadvantaged community should be defined as a community scoring in the top 25% statewide and/or in one of the 22 census tracts that score in the highest five percent for pollution burden, according to the most recently available version of the CalEPA CalEnviroScreen Tool.”


Eureka
Burney
Redding
Chico
Fort Bragg
Yuba City
Lakeport
Auburn
Santa Rosa
Sacramento
Angels Camp
Stockton
Oakland
Merced
Oakhurst
Fresno
Monterey
Visalia
King City
Bakersfield
San Luis Obispo
Needles
Santa Barbara
Los Angeles
San Diego
DAC Tracts
PG&E