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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.

Rulemaking 25-06-019
(Filed June 26, 2025)

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) 2026 INTEGRATED RESOURCE PROCUREMENT PLAN (PUBLIC VERSION)

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Dated: August 10, 2026

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OF THE STATE OF CALIFORNIA

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In compliance with Decision 22-02-004 and Administrative Law Judge Fitch's January 16, 2026 Ruling, *Setting Requirements for Individual Integrated Resource Plans Due June 1, 2026*, and March 9, 2026, Email Ruling, *Granting Joint Request for Extension of Load-Serving Entity Integrated Resource Plan Filings*, Pacific Gas and Electric Company ("PG&E") hereby files its 2026 Integrated Resource Plan ("Plan"), along with an officer verification.[1/]

The confidential version of the Plan will be filed with the Commission's Docket Office.

Respectfully Submitted,

By: */s/ Michelle Melton*
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Dated: August 10, 2026

1/ The Excel workbooks supporting PG&E's Plan will be filed with the Commission's Docket Office in hard copy via archival CD-ROM and omitted from the electronic filing.

OFFICER VERIFICATION

I, Gillian Clegg, say:

I am an officer of Pacific Gas and Electric Company, a corporation, and am authorized pursuant to Rule 2.1 and Rule 1.11 of the Rules of Practice and Procedure of the CPUC to make this Verification for and on behalf of said corporation, and I make this Verification for that reason. I have read the foregoing filing and I am informed and believe that the matters therein concerning Pacific Gas and Electric Company are true to the best of my knowledge. I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed at Oakland, California, this 10th day of August 2026.



Gillian Clegg
Vice President, Energy Policy and Procurement

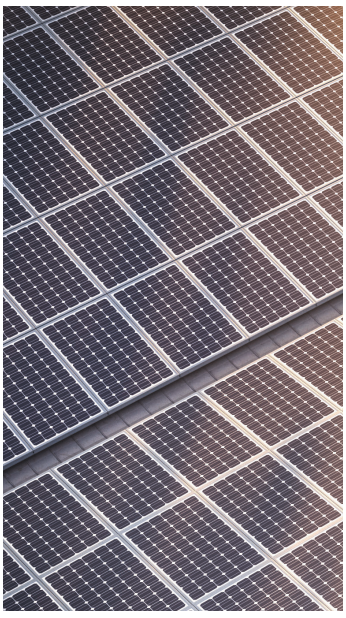
INTEGRATED RESOURCE PLAN











Prepared for the California Public Utilities Commission • August 10, 2026

2026

PACIFIC GAS AND ELECTRIC COMPANY

2026 INTEGRATED RESOURCE PLAN

August 10, 2026

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I. Executive Summary

a. Introduction

The California Public Utilities Commission's (Commission or CPUC) IRP Proceeding is the primary vehicle for California's electric generation planning, focused on ensuring that the electric sector is on track to reliably and affordably meet California's Greenhouse Gas (GHG) emission reductions targets. Pacific Gas and Electric Company (PG&E) is pleased to participate in the 2026 Integrated Resource Planning (IRP) process and to contribute toward California's clean energy goals in a safe, reliable, and cost-effective manner. As one of the largest electric and natural gas energy providers in the United States, PG&E reliably delivers some of the nation's cleanest energy to nearly 16 million people throughout a 70,000-square-mile service area in Northern and Central California.

The 2026 IRP process is underway during a period of high uncertainty, driven by rapid load growth (including data centers). CPUC modeling for this submittal[1] shows that the CAISO system needs renewable and clean firm resources to come online at a faster rate than has ever been achieved historically in order to achieve the state's clean energy goals.[2] While this may be theoretically feasible in a modeling exercise, current need also exceeds the available CAISO interconnection queue.[3]

While PG&E's 2026 IRP is focused on meeting its IRP compliance requirements, PG&E also proposes alternative portfolios to illustrate these challenges and offer potential pathways for the Commission's consideration. The first alternative portfolio examines the costs and benefits of keeping Diablo Canyon Power Plant (DCPP) online beyond 2030. The portfolio demonstrates keeping DCPP online beyond 2030 could save the CAISO system over $1 billion annually and reduce emissions by more than 6 million metric tons per year. PG&E also presents a second alternative scenario with less stringent emissions targets. These less stringent emissions

[1] Table 1 on page 5 of "Administrative Law Judge's Ruling Setting Requirements for Individual Integrated Resource Plans Due June 1, 2026" filed January 16, 2026. Due to uncertainty discussed in this Plan, actual need may be lower. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M595/K085/595085015.PDF

[2] See "December 2025 Resource Tracking Data" on the Commission's "Tracking Energy Development" website. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/summer-2021-reliability/tracking-energy-development/cpuc-resource-tracking-data-reports (accessed August 3, 2026)

[3] See "Cluster 15 Queue Report.xlsx" link on the CAISO website. https://www.caiso.com/generation-transmission/generation/generator-interconnection (accessed July 10, 2026)

targets result in further annual cost savings for customers. With its conforming and alternative portfolio needs in mind, PG&E has requested continued procurement authority in its 2026 IRP. This authority will allow PG&E to continue working towards its later and next decade IRP requirement in a measured approach that may help mitigate against some of the risks and challenges highlighted in its IRP analysis. PG&E recommends that the Commission, other State Agencies, and IRP stakeholders work together to understand and develop an actionable plan to achieve the State's environmental, affordability, and reliability goals.

b. Key Messages

The Commission should use realistic and achievable resource portfolios to inform future IRP decisions. California's resource planning process should reflect current market conditions, development constraints, and achievable build rates. The 2026 IRP Conforming Portfolio assumes renewable resource additions at rates that exceed historical development trends by more than a factor of three, creating significant execution risk. Resource portfolios based on historical average build rates through 2030 provide a more practical foundation for near-term planning and offer a more reliable basis for evaluating system reliability and procurement needs. Relying on this approach for future IRP decisions, including procurement orders and future Reliable and Clean Power Procurement Program (RCPPP) requirements, would (1) better align planning assumptions with demonstrated resource development capabilities; (2) reduce the risk of relying on theoretical resources that may not materialize as modelled; and (3) reduce seller market power to support customer affordability.

Extending Diablo Canyon Power Plant operations through 2045 is a prudent, no-regrets strategy that supports affordability, reliability, and decarbonization objectives. Continued operation of Diablo Canyon would reduce the need for incremental resource procurement while maintaining progress toward California's long-term climate goals. PG&E's analysis shows extending operations could provide system savings exceeding $1 billion annually while reducing greenhouse gas emissions by more than 6 million metric tons per year. Preserving this existing carbon-free generation resource would help mitigate reliability risks, lower customer costs, and provide greater flexibility as the State continues its clean energy transition. Additionally, compared to most other clean firm alternatives, Diablo Canyon does not require new transmission and does not face the same delay risk that may limit the ability of other clean firm resources to contribute to the State's decarbonization goals.

Additional work is needed to identify an affordable and feasible pathway to California's 2045 greenhouse gas emission goals. The current CPUC portfolio assumes aggressive greenhouse gas reduction trajectories that may be difficult and costly to achieve given ongoing challenges

related to permitting, transmission constraints, supply chains, labor availability, tariffs, and project development timelines. Future procurement orders should remain focused on addressing demonstrated reliability needs and not establish IRP compliance penalties for clean energy procurement shortfalls until a clear plan exists to address implementation barriers. Procurement of new generation focused on reliability needs would still maintain progress toward long-term decarbonization objectives while balancing affordability, reliability, and resource development feasibility.

PG&E requests continued procurement authorization to bring incremental resources online.

Over the past several years, increasingly competitive clean energy markets have made it more difficult to procure the resources needed to meet clean energy and reliability requirements. Growing requirements in California and neighboring western markets coupled with anticipated load growth have increased demand for clean energy resources, while reliability needs have made it critical to find the right resources that best fit and complement existing portfolios. Beyond this, increased uncertainty from changes to federal policy (e.g., investment and production tax credits as well as tariffs) and rapid load growth, including large data centers, have made planning for future needs increasingly challenging from both a feasibility and affordability perspective.

PG&E's analysis of its potential Bundled portfolio needs considered four planning requirements: IRP GHG emissions benchmarks set by the Commission; California's RPS compliance requirements; GHG-free energy requirements set by SB 1020 and SB 100; and PG&E's Resource Adequacy (RA) requirements. PG&E forecasts a potential need of 4.6 to 6.6 GW[4] of incremental capacity needed by 2035, growing to roughly 21.9 GW by 2045 to meet these requirements based on the embedded assumptions for scenarios modeled in this IRP filing. PG&E requests Commission approval to continue procurement of resources gradually over the next several years to satisfy these needs. This request is incremental to existing IRP procurement orders and other existing Commission mandates and includes all resource types that may help meet these requirements. While PG&E has identified several significant barriers to achieving the State's decarbonization targets, PG&E believes that it is prudent to continue to make progress

[4] Values represent nameplate capacity based on Study Analysis for scenarios B, C and D and include storage (e.g., battery and pumped storage) capacity. These values exclude Central Procurement Entity (CPE) allocations shown in resource addition tables in the study results sections. The ultimate quantity of resources procured may vary as a result of changes to underlying demand forecasts, requirements, resource mix or other factors. This procurement request is to begin procurement towards these needs regardless of such changes.

towards the State's decarbonization targets. Since the analysis underlying this request assumed realistic assumptions through 2030 while still assuming the State's maintains its 2045 decarbonization trajectory, this request will allow PG&E to continue to procure resources to support decarbonization commitments at a realistic level while the longer-term barriers are addressed.

Given the large amount of procurement PG&E may need to undertake, as well as observed supply constraints and disappearing federal subsidies, PG&E has started to procure resources to meet these anticipated needs. Without continued authorization, PG&E is concerned there will not be sufficient time for resources to come online, and to mitigate against risks such as a sudden increase in forecasted demand, project development delay or failure, changes to compliance rules such as those being considered in the RCPPP, and supply constraints as LSEs work towards increasingly stringent clean energy and reliability requirements. PG&E will continue to monitor these drivers and associated procurement needs to meet its RPS, GHG-free energy, and GHG-emissions targets.

PG&E supports expanded considerations for emerging technologies and load management in future plans. As PG&E works to diversify and optimize its portfolio to support California's decarbonization goals, PG&E believes emerging technologies and load management will play an increasingly important role. Accordingly, PG&E applauds the Commission for the inclusion of more emerging technologies in their modeling, including enhanced geothermal (EGS) as a candidate resource in analysis for this Plan and carbon capture and sequestration (CCS) retrofits as a candidate resource in the 27-28 Transmission Planning Process portfolios.[5] Even if these resources are not identified in the least-cost portfolios, their inclusion adds credibility to the long-term results and brings the modeling in closer alignment with the CARB Scoping Plans upon which the GHG targets are based.[6]

However, analysis underlying this 2026 IRP does not consider CCS, and it does not fully consider distributed energy resources (DERs), including behind-the-meter (BTM) resources as explicit

[5] Please refer to Slide 80, "Candidates for CCS Technology Retrofits". https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2027-2028-tpp/mag-webinar_final_slides_20260616.pdf (accessed August 3, 2026)

[6] https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents

resources to be optimized within the portfolio.[7] Instead, the Commission reduces demand by energy produced (or saved) for demand side resource programs (e.g., BTM PV, storage, energy efficiency, electrification) to calculate a retail sales load that needs to be served by bulk supply resources.

Moreover, the IRP does not include what PG&E has called "breakthrough" load management (e.g., emerging programs such as vehicle-to-grid) options to meet system demand. For example, although the Commission developed Vehicle to Grid Integration (VGI) as a candidate resource for the 2023 Preferred System Plan (PSP),[8] this technology is not enabled in the analysis supporting this Plan. Incorporating VGI technology, and other advanced load management solutions, into future Plans could improve reliability by reducing peak impacts, reducing emissions by shifting demand into hours when the sun is shining, and improving affordability if identified to be cheaper than supply-side alternatives.

c. Actions to Bridge the Gap Between System Need and Market Realities

California's current decarbonization pathway assumes renewable deployment rates that significantly exceed recent historical trends, creating potential challenges to achieving the State's 2030 and 2035 greenhouse gas reduction targets. To maintain progress toward long-term climate goals, California should assess the feasibility barriers facing clean energy and transmission development, establish a roadmap to address those barriers, and incorporate a feasibility assessment into CARB's upcoming Scoping Plan update. Until a clear implementation strategy is in place, future procurement orders should remain focused on addressing demonstrated reliability needs and not establish compliance penalties for clean energy procurement shortfalls. PG&E provides the following three recommendations for the Commission to take to begin to address these issues:

[7] Candidate resources refer to potential supply- and demand-side technologies that RESOLVE can select to address reliability or renewable/clean constraints in its "least cost" portfolio. Being selectable is essential to determining what resources LSEs should prioritize and at what levels. Assessing selectable resources also provides quantitative support for rules that the Commission may adopt to promote the development of resources included within the plans. Without considering all viable options, including options that CARB assessed in establishing the GHG targets underlying this filing, there is an affordability risk where the "least cost" portfolio may in fact be more expensive than a portfolio that considers more options.

[8] Inputs & Assumptions, 2022-2023 Integrated Resource Planning, October 2023, page 106. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf (accessed August 3, 2026)

1. ***The Commission, other State agencies, and IRP stakeholders should establish a clear roadmap to bridge the gap between current conditions and the resource development needed to meet long-term climate objectives.*** A comprehensive assessment is needed to evaluate the feasibility of achieving the required deployment rates for each resource technology and geographic region. This effort should identify the barriers limiting development and establish a timeline of actions needed to remove those constraints. PG&E has identified some specific potential implementation barriers to investigate and actions to take:
    a. Solar and Wind: The two major barriers to solar and wind adoption are resource availability and cost. First, fewer solar and wind resources are included in the CAISO Interconnection Queue than what is needed for these portfolios to meet the Commission's established GHG-reduction benchmarks.[9] Without these resources in the queue, it is unlikely that enough capacity could be built in time to meet State interim emissions targets. Potential drivers of the availability barrier to consider are procurement signals (current compliance rules focus mainly on ensuring reliability and not on reducing GHG emissions), land-use issues, and supply-chain competition and delays. Regarding cost, the assumptions underlying the Conforming scenario do not consider expiring tax credits under the federal "One Big Beautiful Bill Act" (OBBBA).[10] This increases the cost for many resources in the current queue if they miss deadlines for the tax credits, making those resources likely candidates to drop out of the queue once refreshed by the CAISO.
    b. Enhanced Geothermal: System modeling identifies both in-state and out-of-state geothermal and enhanced geothermal systems (EGS) capacity as part of the future portfolio mix.
        i. There is a lack of in-state EGS projects in the CAISO interconnection queue, driven in part by California's non-standard permitting process,

[9] As of July 21, 2026, the CAISO Interconnection Queue includes 11.9 GW of solar and 0.8 GW of wind projects expected to come online through 2030, compared to 28.1 GW of new solar and 1.3 GW of in-state wind additions in the Conforming Portfolio over the same period.

[10] Inputs & Assumptions, 2024-2026 Integrated Resource Planning, February 2026, page 43. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf

which can delay projects by years.[11] Without changes to the permitting process, it is imprudent to rely on this resource in IRP portfolios. While California's geology is ideal for EGS, and significant potential exists, in-state development also suffers from a lack of subsurface analysis that would lower risk for developers.[12] For example, the U.S. Department of Energy's (DOE) Utah Frontier Observatory for Research in Geothermal Energy project drilled exploration wells and published the results. Providing this information helped spur the EGS development that Utah is experiencing today.

ii. Regarding out-of-state EGS, inter-regional transmission availability and accurate cost assumptions are the largest bottlenecks. New transmission is needed to access the large EGS potential in Utah[13] and Nevada.[14] But currently infeasible in-state geothermal is crowding out out-of-state geothermal in IRP modeling. Since transmission projects take years to build, planning needs to start soon or access to these projects will be further delayed.

c. Transmission: In parallel, the Commission and other state agencies should work with CAISO to conduct a targeted reassessment of the CAISO transmission plan to better align transmission investments with current market conditions, realistic renewable development expectations, and the infrastructure needs of emerging technologies.

Addressing both resource and transmission challenges will be critical to maintaining progress toward California's decarbonization goals.

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[11] https://www.thinkgeoenergy.com/californias-geothermal-growth-faces-permitting-hurdles/ (accessed August 3, 2026)

[12] https://cdn.catf.us/wp-content/uploads/2026/05/20122941/California-Testbed-Report.pdf (access August 3, 2026)

[13] There is an estimated 4.3 GW of capacity potential at the Cape Station site in Beaver County, UT. See https://www.sec.gov/Archives/edgar/data/1853868/000162828026025821/fervoenergy-sx1.htm. (accessed August 3, 2026)

[14] As of July 15, 2026, the NV Energy has 1.7 GW of active and executed interconnection requests for geothermal projects with an online date beginning in 2026 in their interconnection queue. See NV Energy, "IPP OATT Applications for Interconnection," at https://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/3.5.1_Queue_Status_-_07-15-2026.pdf (accessed July 23, 2026)

2. ***The Commission should work with CARB to reassess electric sector pathways as part of its upcoming Scoping Plan update.*** California's energy landscape has evolved significantly since the development of the most recent Scoping Plan, including increased electricity demand and resource development challenges. As CARB revisits statewide emissions reduction pathways, it should incorporate a formal feasibility assessment that evaluates whether resource availability, emerging technology maturity, evolving technology costs and expiring tax credits, and infrastructure buildouts can realistically be achieved within the required timeframes. The reassessment should clearly identify the conditions necessary for success and establish a corresponding action plan to address barriers and maintain progress toward statewide climate goals.
3. ***Future procurement should remain focused on reliability needs until feasibility barriers are addressed.*** The Commission has already authorized significant procurement to meet forecasted reliability requirements through 2032.[15] For future planning horizons and any incremental resource needs beyond existing procurement orders, procurement decisions should prioritize maintaining system reliability and supporting load growth. Compliance penalties for additional procurement driven solely by greenhouse gas reduction targets should be deferred until there is a clearer understanding of the feasibility of achieving the required resource build rates and a defined plan to address identified barriers. This approach would help balance reliability, affordability, and decarbonization objectives while reducing the risk of relying on assumptions that may not be achievable.

d. Study Design

PG&E's 2026 Integrated Resource Plan evaluates how the company can continue delivering safe, reliable, affordable, and clean energy while meeting California's long-term greenhouse gas reduction requirements. The filing analyzes five scenarios, including two conforming portfolios required by the CPUC and three alternative portfolios designed to test more realistic resource development assumptions, the value of extending Diablo Canyon Power Plant operations through 2045, and a modified interim emissions trajectory.

[15] Refer to D.19-11-016, D.21-06-035, D.23-02-040, and D.26-02-057.

- Scenario A: Conforming Assumptions
- Scenario B: Alternative #1, Market-Informed Resource Expansion
- Scenario C: Alternative #2, Scenario B plus 2045 Diablo Canyon Extension
- Scenario D: Alternative #3, Scenario C plus Modified Interim GHG Emission Benchmarks
- Scenario E: Conforming Assumptions, Scenario A modified by DWR Procurement

The alternative scenarios highlight that near-term resource buildout assumptions, technology costs, transmission availability, and market feasibility are critical drivers of both emissions outcomes and customer costs and need to be included in statewide planning efforts to help identify gaps and practical solutions.

PG&E retained certain common assumptions, including sales forecasts and commodity prices, to isolate the impacts of specific scenario changes and provide clearer planning insights for Commission consideration.

Each of the portfolios were tested against PG&E's RPS compliance requirements, the IRP's LSE GHG benchmarks, the GHG-free energy requirements for 2035, 2040 and 2045, and other key bundled portfolio requirements, such as system RA needs, to determine the need for any incremental additional resources and to identify the resources that would be added to fit any such incremental additional resource need.

PG&E's 2026 IRP procurement forecast is inclusive of the Commission's recent February 2026 procurement order[16] targeting 6,000 MW of additional new resources net qualifying capacity (NQC) to come online between 2030 and 2032, including the portion required to be met with clean firm and/or long-duration storage resources. It also includes resource development and procurement assumptions related to PG&E's remaining portion of 2021[17] and 2023[18] Mid-Term Reliability (MTR) procurement.

Given the 2026 IRP planning horizon extends through 2045, a majority of PG&E's contracted portfolio resources will have expired beforehand. As a result, PG&E developed a methodology for incorporating existing resources expected to be available to the market into its process for

[16] D.26-02-057

[17] D.21-06-035

[18] D.23-02-040

determining future planned resource additions. This methodology separates resources based on whether they are located in local transmission capacity planning areas.

e. Study Results

PG&E's bundled portfolio results demonstrate compliance with the requirements listed above. To meet these requirements, bundled portfolio results show a need to procure additional resources. Additional resources will be needed by 2030 for PG&E to meet its GHG emissions planning targets and to stay on a trajectory to meet California's GHG-free energy requirements, beginning with 90 percent GHG-free by 2035.[19] Among the scenarios analyzed, PG&E supports the Commission utilizing Scenario D for portfolio planning purposes as the further extension of Diablo Canyon is demonstrated to be the lower cost solution for maintaining reliability and mitigating system GHG emissions. Modifying GHG emission benchmarks—which were based on the 2024 IEPR sales forecast—to levels aligning with the lower 2025 IEPR sales forecast also shows lower costs to customers as it may limit costly overbuild.

In its plan, PG&E is requesting approval to procure GHG-free resources gradually over the next several years based on the procurement planning scenario approved by the Commission for PG&E in this IRP, adjusted for any changes to specified key inputs. For example, PG&E would adjust its approved procurement based on the latest load forecast from the Integrated Energy Policy Report (IEPR). With this new proposed procurement, PG&E would demonstrate how it contributes towards meeting PG&E's IRP planning requirements for 2035 while also placing PG&E on a trajectory for meeting its expected post-2035 requirements. Additionally, focusing on procurement needs for 2035 enables more time for load growth, including transportation electrification, and demand-side solutions to develop before procuring resources for meeting post-2035 requirements.

f. Action Plan

The Action Plan described in Section IV demonstrates the alignment between PG&E's planning and procurement strategy, outlines current and planned activities to address disadvantaged communities (DACs), and notes what actions PG&E requests for the Commission to consider in supporting the effective implementation of its plans. PG&E's 2026 IRP Action Plan is highly influenced by PG&E's climate strategy and supports reducing GHG emissions in California. Each subsection of the action plan provides a clear overview of PG&E's progress towards achieving

[19] SB 1020 established GHG-free energy targets of 90 percent and 95 percent for 2035 and 2040, respectively. SB 100 established a 100 percent GHG-free energy requirement for 2045.

its GHG target compliance and offers valuable contributions to meeting California's clean energy goals in a safe, reliable, and cost-effective manner.

PG&E has a wide array of programs available to customers residing in DACs. These programs have evolved over the years and now include other programs that offer greater access to clean technologies that help minimize criteria air pollutants both inside customer homes and in the broader community. PG&E anticipates that there will continue to be more programs developed to help address and mitigate poor air quality in DACs, particularly programs that have a direct impact on air quality, such as expanding access to EVs and building electrification.

g. Lessons Learned

PG&E recognizes that the Commission is still pursuing development of the RCPPP during this IRP cycle's filing process. PG&E continues to support developing the RCPPP, which should lead to more efficient and effective procurement of new reliable and clean resources.

In the Lessons Learned section, PG&E has included recommendations in the following areas for further improvement or greater collaboration in future IRP proceedings:

1) Enhancement of the Commission's capacity expansion modeling capabilities;
2) Improvement in the Commission's reliability assessment efforts to adequately address climate change impacts and location specific resource requirements;[20]
3) Improvement in key IRP modeling assumptions; and
4) Making progress towards more integrated system planning.

More detailed information and context for each of these points stated above can be found in Section V. Lessons Learned.

[20] Location specific requirements driven by transmission limitations.

II. Study Design

In this section PG&E describes how it developed its 2026 IRP filing, including:

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

a. Objectives

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

- **Clean energy:** For decades PG&E has been a leader in developing clean energy technologies in California and has always met or exceeded California's ambitious renewable requirements. Among other important goals, PG&E's IRP analysis is focused on facilitating a path for PG&E to meet its clean energy requirements under SB 100 and SB 1020. PG&E is also on track to meet its 2030 commitment of 75% clean. However, there is significant uncertainty about whether the State will stay on the Commission's Preferred System Plan trajectory of GHG emissions targets from 2030 through 2040 due to the substantial acceleration of renewable buildout required relative to historical build rates. While PG&E presents a conforming portfolio that meets all of its targets, it also presents alternative scenarios where the 2045 target is met but these interim targets are not achieved.
- **Reliability:** Maintaining reliability for both the overall electric system and local segments of the system is critical, especially as California transitions towards higher shares of GHG-free generation resources, many of which are intermittent.
- **Affordability:** PG&E's IRP analysis focuses on resource scenarios that meet the State's clean energy and reliability goals in a least-cost manner to customers. PG&E provides a system average bundled electric rate forecast in compliance with the CPUC's requirements for investor-owned utilities (IOUs).

For its IRP filing, PG&E developed the following five scenarios comprised of the two conforming scenario requirements as well as three additional alternatives that focus on specific changes to certain conforming scenario assumptions:

- Scenario A: Conforming Assumptions
- Scenario B: Alternative #1, Market-Informed Resource Expansion
- Scenario C: Alternative #2, Scenario B plus 2045 Diablo Canyon Extension
- Scenario D: Alternative #3, Scenario C plus Modified Interim GHG Emission Targets
- Scenario E: Conforming Assumptions, Scenario A modified by DWR Procurement

Scenario A satisfies PG&E's conforming portfolio requirements as outlined in the 2026 IRP Filing Requirements[21] while *Scenario E* presents the modified conforming bundled portfolio supply mix based on the AB 1373 procurement assumptions provided by the CPUC for PG&E.[22]

For the remaining scenarios, PG&E assumes the sales forecast and the 2045 GHG emission target to be the same as the CPUC PSP. *Scenario B* reflects a number of changes to the conforming portfolio supply and requirement assumptions, including changes to the annual new resource build rate and technology mix assumptions for the front-end of the planning horizon, as well as updated resource costs for new resources.

Scenario C is based on the same modified assumptions as Scenario B, but reflects the impact from PG&E's Diablo Canyon nuclear power plant having operations extended through the full permitted 20-year renewal period approved by the Nuclear Regulatory Commission (NRC) in April 2026.[23]

Lastly, *Scenario D* builds off of the assumptions used for Scenario C, but modifies the GHG emission interim targets for 2035 and 2040 based on a straight-line trajectory from the achievable 2030 system GHG emissions identified in Scenario B and the 8 MMT electric sector target adopted for 2045. The customer sales and GHG emission benchmark targets used for each scenario are summarized in Table 1 below.

[21] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/updated-filing-requirements-overview-document.pdf (accessed August 3, 2026)

[22] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/ab-1373-allocations.pdf (accessed August 3, 2026)

[23] https://www.nrc.gov/docs/ML2602/ML26022A077.pdf

TABLE 1
PG&E'S IRP SCENARIOS

Line No.			2030	2035	2040	2045
1	GWh	CAISO Metered System Sales	218,398	267,057	298,823	316,854
2		PG&E Metered System Sales	104,793	130,179	145,985	155,228
3		PG&E Metered Bundled Sales	36,271	47,268	53,014	56,391
4	MMT	CAISO GHG Benchmark (Scenarios A & E)	19.50	15.65	12.95	6.68
5		PG&E GHG Benchmark (Scenarios A & E)	2.92	2.44	2.07	1.07
6	MMT	CAISO GHG Benchmark (Scenarios B & C)	N/A	15.65	12.95	6.68
7		PG&E GHG Benchmark (Scenarios B & C)	N/A	2.44	2.07	1.07
8	MMT	CAISO Benchmark (Scenario D)	N/A	28.56	17.41	6.68
9		PG&E GHG Emissions Benchmark (Scenario D)	N/A	4.46	2.78	1.07

PG&E's approach to developing the scenarios presented above focused on achieving the following objectives as identified for each scenario:

- Scenario A, and subsequently Scenario E, were developed to satisfy the CPUC's 2026 IRP filing requirements, which included the use of all provided supply and demand input assumptions.
- The primary objective of Scenario B is to develop a realistic CAISO portfolio reflecting the current market conditions based on changes to certain key input assumptions that include restrictions on the rate and technology mix of new resource development through 2030 as well as modified technology cost assumptions for new resources
- Scenario C specifically focuses on determining the projected customer rate and emissions impact that would result from a further extension of PG&E's Diablo Canyon nuclear power plant given its availability as an existing GHG-free generation resource.
- Scenario D was developed to system savings due to a modified GHG emissions target trajectory that plans for a straight line GHG emissions target between the achievable GHG emissions shown for 2030 and CARB's electric sector target of 8 MMT for 2045.

Further details regarding PG&E's input assumptions and modeling approaches for both the system and bundled portfolios are provided in Section II.b below and the resulting PG&E bundled and CAISO system portfolios are presented in sections III.a and III.n, respectively. PG&E elected to leave certain input assumptions unaltered, such as natural gas and GHG

allowance commodity prices,[24] and the customer sales forecast,[25] in order to limit variables being changed, though PG&E's internal expectations still differ from those planning assumptions used for the 2026 IRP.

b. Methodology

i. Modeling Tool(s)

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

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

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

A. CAISO System Tools

1) **CPUC's RESOLVE Model:** PG&E relied on the RESOLVE capacity expansion results solely for capacity additions (e.g., system-level resource portfolios) for the ease of comparison of results against the Conforming Portfolio. Since the commitment and dispatch modeling and the time granularity in RESOLVE are highly simplified, PG&E used PLEXOS as well as its own proprietary models, as described below, which take the RESOLVE capacity expansion results as inputs to develop market price forecasts needed for assessing PG&E's bundled generation portfolio.
2) **PLEXOS v10.0 R04:** This model establishes the CAISO hourly dispatch profile as a function of the CAISO system load and dispatchable resources available during each hour of the IRP horizon. PG&E developed this model to align with the CPUC's IRP methodology while taking full advantage of PLEXOS's hourly[26] production-cost granularity. Key inputs for this model are the CAISO system-level resource mix forecast and CAISO load, which come from the specified RESOLVE model run for each modeled scenario. The model also relies on natural gas commodity prices from the

[24] Based on the RESOLVE model inputs.

[25] Based on the 2024 IEPR Forecast.

[26] Either 8,760 or 8,784 hours depending on the study year.

CEC's 2023 IEPR Mid scenario[27] and GHG prices from the 2022 CEC California Energy Demand (CED) Low scenario.[28] The 2023 CEC gas price forecast was used by the CPUC in development of the system portfolio that informs PG&E's conforming IRP scenario.

3) **PG&E's Hourly Power Price Forecast Tool:**[29] This model establishes the hourly power prices by using the net-load determined in PLEXOS against dispatchable natural gas resources within CAISO. The model relies on the same gas commodity and GHG prices as PG&E's PLEXOS model as well as a list of power plants and their respective heat rates. The hourly prices are used as an input into calculating the bundled portfolio generation revenue requirements.

4) **PG&E's Capacity Price Forecast Tool:**[30] [redacted]

5) **PG&E's REC Price Forecast Tool:**[32] [redacted]

[27] 2026 IRP Inputs & Assumptions, p.173: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf (accessed August 3, 2026)

[28] Id. at 168.

[29] Note this model is PG&E's proprietary model and is used routinely by PG&E as part of its forward curve development process, and variants have been used in past regulatory filings, including in ERRA forecast proceedings.

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

[redacted]

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

[redacted][33]

B. Bundled Portfolio Analysis Tools

1) **CPUC's CSP Model:** The CSP model is used to quantify PG&E's GHG emissions and local air pollutants associated with serving its bundled load on an hourly basis for PG&E's IRP scenarios.
2) **PG&E's Procurement Portfolio Planner (P^3):** This proprietary model developed by PG&E forecasts PG&E's electric portfolio generation and procurement costs.[34] P^3 includes the electric 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 the forecast hourly price. The generation and cost outputs from P^3 serve as the primary inputs into PG&E's bundled generation revenue requirement model, including determining CAISO wholesale market costs and revenues.
3) **PG&E's RPS and GHG-free Stochastic Model:** PG&E's forecasted bundled RPS and GHG-free energy positions are determined using PG&E's RPS and GHG-free energy stochastic model. PG&E utilizes this model for RPS position planning in the RPS Plan proceeding, most recently in PG&E's draft 2026 RPS Plan.[35] The model accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to support position planning within designated levels of non-compliance risks.

[33] PG&E applied the same methodology for calculating the forecasted GHG-free market price benchmark (MPB) prices.

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

[35] PG&E's Draft 2026 Renewable Energy Procurement Plan, R.26-07-003, https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=877764 (accessed August 3, 2026)

4) **PG&E's Slice-of-Day (SoD) System RA Capacity Model:** PG&E utilizes a structured query language (SQL) based model to determine its hourly SoD[36] system RA net qualifying capacity (NQC) supply and projected SoD net open positions by month for the IRP model horizon. Under the SoD framework, an LSE must show sufficient capacity to meet 24 separate hourly RA requirements across each month of each year. The requirements are based on the 24-hour load profile associated with the CAISO's "worst day"[37] of the month plus the applicable Planning Reserve Margin (PRM) adjustment.[38] The hourly SoD NQC supply volumes for resources not treated as flexible energy storage for RA counting[39] are based on the supply values published by the CPUC in its Master Resource Database (MRD) while SoD RA discharge supply for flexible energy storage resources can be counted in any of the hourly slices provided the volumes are technically feasible and the portfolio contains sufficient excess charging capacity to support the level of energy storage discharge.[40] PG&E models the supply from its flexible energy storage resources consistent with the storage heuristic methodology used in its 2027 Energy Resource Recovery Account (ERRA) Forecast,[41] which seeks to minimize PG&E's SoD RA open position across all hours while satisfying the SoD RA charging sufficiency requirements.
5) **PG&E's Bundled Resource Addition Planning Process:** PG&E developed a resource planning process to determine the mix of new and existing generation and storage resources to be added to its bundled electric portfolio under scenarios where the existing set of resources in PG&E's electric portfolio are unable to meet certain operational and/or policy constraints. The process is designed to first determine resource additions from existing resources expected to be available for future contracting during the planning horizon before considering new build resource

[36] D.22-06-050 established the SoD framework for system RA compliance requirements, which became fully operational for LSEs on January 1, 2025 after an initial testing period in 2024.

[37] In D.22-05-050, the "worst day" is defined as the day of the month that contains the hour with the highest coincident peak load forecast.

[38] PG&E applies an additional internal reserve quantity.

[39] Limited to 4- and 8-hour battery energy storage system (BESS) resources for PG&E's IRP.

[40] Does not reflect changes adopted in D.26-07-008.

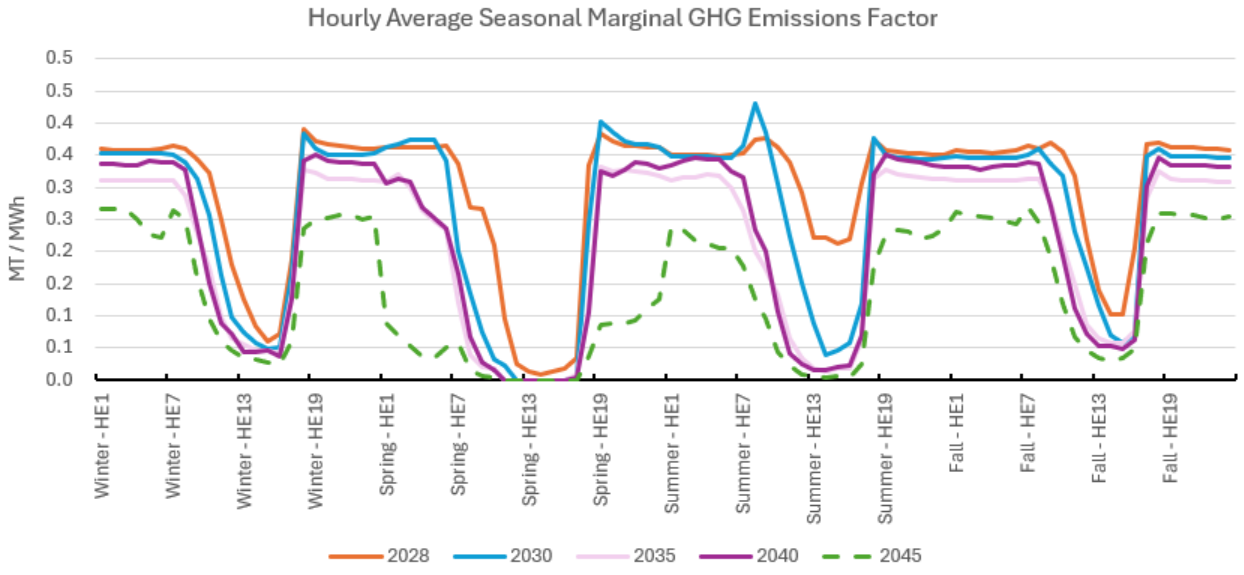
[41] More information on PG&E's storage modeling methodology can be found in its 2027 ERRA Forecast on pages 5-8 to 5-10.

additions from the pool of resources added as part of the optimized capacity expansion system portfolio buildout for each scenario. The process focuses on meeting the following requirements in sequential order beginning with the GHG emission targets for PG&E.

IRP-mandated 2030, 2035, 2040, and 2045 LSE GHG planning targets

The process is designed to meet the LSE GHG benchmarks for 2030, 2035, 2040, and 2045 based on the GHG emission methodology utilized in the CSP model. The primary input assumption for determining a candidate resource's GHG emission impact on PG&E's portfolio is the marginal hourly GHG emission impact assumption derived from the CSP model. Figure 1 shows the hourly average GHG emission reduction impact by season associated with incremental GHG-free generation for the CSP model. Candidate resources that generate in hours and seasons with higher emissions reductions impacts will have a greater impact than resources with higher generation in hours of low emission reduction factors. For example, an incremental MWh of solar generation provides less of an emissions reduction benefit than a baseload clean resource, as more midday solar hours provide no emissions reductions benefit due to clean resource curtailments or exports compared to other hours.

FIGURE 1
HOURLY AVERAGE SEASONAL MARGINAL GHG EMISSIONS FACTOR



Marginal hourly GHG emission impact rates are calculated based on adjusted System Power emission intensities from the CSP model. The adjustments account for CSP model hours where

there is non-displaceable system power, which result in modeled system GHG emissions being allocated to all LSEs on a pro rata basis.[42] Since additional GHG-free energy supply in these hours has no impact on an LSE's GHG emissions, PG&E adjusts the System Power emission intensity to zero in such hours when determining a resource's impact on PG&E's total GHG emissions.

When determining resource additions, PG&E first considers its proportional share of existing resources it expects will be available for future contracting based on publicly available data regarding existing contract terms. Additional details regarding PG&E's assumptions related to existing resources are included in Section III.g. If PG&E's electric portfolio is still exceeding PG&E's GHG emissions target once existing resources are accounted for, PG&E then begins incorporating new build resources into its planned portfolio additions based on the mix of new build resources added to the system for each scenario. Once the portfolio has satisfied its GHG emissions target requirements with additions of existing and new build resources, PG&E determines if additional resources are required to meet the following remaining compliance requirements.

California's annual RPS

PG&E uses the adopted annual RPS requirement targets based on 52 percent for 2027 and 60 percent for 2030 RPS requirements. After 2030, the RPS requirement is held at 60 percent while the supply content constraint transitions to a GHG-free requirement trajectory.

Annual GHG-free[43] requirements based on SB 1020 and SB 100

In SB 100 California adopted a 100 percent GHG-free energy requirement by 2045 while more recently the state adopted interim targets of 90 percent by 2035 and 95 percent by 2040 in SB 1020. PG&E developed an annual GHG-free requirement constraint based on these target year requirements to develop portfolios that position PG&E to meet the 2045 requirement.

Estimated monthly bundled SoD System RA open position

To ensure PG&E's IRP portfolio is meeting the SoD System RA requirements required by the IRP filing requirements and Public Utilities Code Section 454.52(a)(1)(E), PG&E sets monthly open position targets for each year of the IRP modeling horizon. These targets are based on

[42] Adjustments also account for the 'System Power Emissions Adjustment %' factors of 12.08%, 22.65%, 17.25%, and 32.46% for 2030, 2035, 2040, and 2045, respectively.

[43] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220SB1020.

estimated bundled peak load requirements[44] and system RA supply from PG&E's bundled electric portfolio prior to any planned resource additions from existing or new build resources.

Once PG&E's GHG emissions and clean energy requirements are expected to be met with planned additions of existing and new build GHG-free resources, PG&E determines whether any additional procurement will be needed to satisfy its expected SoD System RA requirements. If additional procurement is needed for SoD System RA requirements, PG&E first considers its proportional share of remaining available existing resources before adding additional new build BESS supply until PG&E SoD System RA requirements are met.

6) **PG&E's Bundled Generation Revenue Requirement Model:** PG&E utilizes a SQL-based revenue requirement model for calculating gross and net bundled generation revenue requirement costs by established generation cost recovery types. Cost recovery types include categories such as Energy Resource Recovery Account (ERRA), Power Charge Indifference Adjustment (PCIA), Cost Allocation Mechanism (CAM), etc. with net cost calculations consistent with established methodologies and PG&E's commodity price assumptions for each scenario.

ii. Modeling Approach

This section describes PG&E's modeling approach for its Bundled Portfolio. For the CAISO system portfolio, PG&E utilizes the Commission's required RESOLVE model as a starting point. The changes made to the RESOLVE model assumptions for alternative scenario development are described in Section II.b.iii.

A. Overview

PG&E's 2026 IRP modeling effort is guided by two key modeling principles:

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

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

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

[44] SoD System RA requirements included a planning reserve margin (PRM) adder of 18 percent based on the current PRM level adopted in D.25-06-048.

1) GHG emission planning benchmark established by CPUC
2) California's RPS targets
3) California's GHG-free energy targets
4) PG&E's system capacity needs to meet SoD RA requirements and Reliability Procurement Need[45] (RPN)

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 that scenario. These assumptions, along with assumptions for CAISO system level resource mix, are required to determine whether PG&E's portfolio meets the desired requirements listed above and to calculate PG&E's bundled portfolio revenue requirements. Certain assumptions have been specified by the Commission as part of the filing requirements.

Step 2: Determine Incremental LSE Resource Needs

Once the assumptions for the analysis have been established, the next step is testing PG&E's existing and planned portfolio of bundled resources[46] against the four portfolio requirements and determining PG&E's incremental resource need, if any.

Step 3: As Necessary, Incorporate Additional Resources

If Step 2 above shows a need for additional resources—for instance, to meet the GHG planning benchmark—an additional step is taken to determine the portfolio additions to fulfill that need.

B. Modeling Process Details

This section includes a more detailed description of the modeling processes underlying the three-step approach described above and provides additional discussion on the rationale 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:

[45] Perfect capacity equivalent reliability need model included in the Resource Data Template.

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

a) *Establish Bundled Energy and Peak Load Forecasts* – As discussed in the previous section, PG&E used the CPUC's prescribed 2024 IEPR energy forecast for PG&E bundled customers across all scenarios. PG&E utilized the 2024 IEPR forecast data to derive its bundled SoD System RA requirements, which are consistent with the annual peak requirements for PG&E's bundled customers that were provided by the Commission for the IRP.

b) *Establish Price Inputs* – Natural gas, GHG allowance, new resource technology cost, and RA market price inputs are used for developing hourly energy, REC,[47] and RA prices. PG&E utilized the following price assumptions for these commodity derivations:
   1) Natural Gas and GHG Allowances – To develop the hourly energy prices for the scenarios, PG&E used the 2023 IEPR natural gas and 2022 CED GHG price forecasts. The GHG price forecast is also used in calculating the cap-and-invest auction revenues for forecasted electric distribution utility (EDU) allowances.
   2) Technology Cost – For developing REC prices, PG&E used the Commission's 2026 IRP LCOE forecasts for the conforming scenario.

c) *Develop CAISO System Portfolio* – For PG&E's Conforming Scenarios, this is simply the Commission's reference system portfolio. For the alternative scenarios, the CAISO system portfolios are based on RESOLVE's capacity expansion optimization model results reflecting the scenario specific input assumptions. The following alternate assumptions were used (see Section II.b.iii for more detail). PG&E applied the assumptions to the relevant portfolios as noted in parentheses below:
   1) Resource Costs (Scenarios B, C, and D) – The resource cost assumptions from the 26-27 Transmission Planning Process[48] were used instead of those from the 2026 LSE Filing Requirements, as they are based on more recent market conditions.
   2) Near-Term Build Rate (Scenarios B, C, and D) – The new build from 2026-2030 was limited to the historical average from 2024-2025 by technology type[49] to understand how the portfolio would be impacted if LSEs cannot procure at the levels shown in the Conforming Scenario.

[47] PG&E used the REC price derivation methodology to calculate a GHG-free MPB price forecast.

[48] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf (accessed August 3, 2026)

[49] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-december-2025-release.pdf.

3) Extending the Operation of DCPP through 2045 (Scenarios C and D) – The full operations of DCPP were extended through 2045 to understand the impact on GHG emissions, total resource costs, and total build rate.
4) Modified GHG Target (Scenario D) – The GHG emission targets for 2035 and 2040 were modified based on a straight-line trajectory from the achievable 2030 system GHG emissions and 8 MMT electric sector target adopted for 2045. Note no GHG emissions target was modeled for 2030, although 2030 emissions were still calculated, as PG&E incorporated a fixed build rate rather than allowing RESOLVE to optimize the portfolio to meet the 2030 target.

d) *Develop 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 for each scenario, natural gas prices, and GHG prices. 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 the REC price forecast model 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, [redacted] Given this approach, the modeling results from PG&E's Capacity Price Forecast Tool vary based on differences in the future CAISO system-level resource mix rather than forecasted energy prices.

f) *Develop REC Prices* – PG&E developed REC price forecasts using PG&E's REC Price Forecast Tool. This tool, as described above, [redacted]

[redacted]

[redacted]

Step 2: Determine Incremental LSE Resource Needs

For PG&E's Conforming Scenarios, PG&E modeled its bundled supply portfolio based on its latest data on existing contracts, future procurement for existing mandated programs, planned power purchase agreement (PPA) expirations (e.g., CHP) and utility-owned generation (UOG) (e.g., DCPP) resource retirements to determine PG&E's additional resource need, if any.[51]

For all scenarios, PG&E included procurement under various CPUC-mandated programs, including GHG-free resources for which it has sought approval pursuant to the 2021, 2023, and most recently 2026 IRP Procurement Track mandates.

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

a) *GHG Emissions:* PG&E's GHG emissions and need for incremental resources were calculated using the CPUC-provided CSP model.
b) *RPS Requirement:* PG&E's bundled supply portfolio was tested to identify if additional renewables were needed to meet RPS compliance requirements.
c) GHG-free Requirement: PG&E's bundled supply portfolio was tested to identify if additional resources were needed to meet GHG-free energy compliance requirements.
d) *RA Requirement:* PG&E's System RA requirements and need for incremental resources were calculated using both the CPUC-provided RDT reliability calculator and PG&E's Bundled SoD System RA compliance model.

Step 3: If Necessary, Acquire Additional Planned Resources

A bundled portfolio resource addition process step is triggered if Step 2 identifies a need for additional resources to meet PG&E's GHG planning benchmark, RPS requirements, GHG-free requirements, or system RA requirements. For its 2026 IRP, all of PG&E's portfolios required PG&E to perform the resource addition process step.

C. Revenue Requirement and Rates Modeling

PG&E developed its revenue requirement and System Average Bundled Rates (SABR) for the Conforming Scenario utilizing the 2024 IEPR sales forecast, consistent with the 2026 IRP filing

[51] For IRP planning purposes, PG&E assumes no re-contracting with expiring CHP facilities. This is an IRP planning assumption only.

requirements published on January 16, 2026. The baseline revenue requirement forecast includes the following components:

Distribution (D)

- The Distribution revenue requirement forecast includes all approved and pending revenue requirement applications. Forecast years 2027 through 2030 reflect PG&E's pending 2027 General Rate Case (GRC), as updated July 2, 2026. Subsequent years escalate the prior year's base revenue requirement using an escalation factor of approximately 4 percent. In addition to the GRC base revenue requirement, the distribution revenue requirement reflects incremental revenue requirements for EV infrastructure, Alternative-Fuel Vehicle, Wildfire Mitigation and Catastrophic Events (2021-2024), CPUC Fee, Family Electric Rate Assistance program, Mobile Home Park investments, Hazardous Substance Mechanism, Wildfire Gas and Safety Costs, Billing System Upgrade, and Kincaid- Dixie Catastrophic Event Memorandum Account and Wildfire Expense Memorandum Account.

Transmission (T)

- The transmission revenue requirement includes the currently effective Transmission Owner (TO) base revenue requirement for 2026 and forecasted TO21 Rate Year 2027 revenue requirement for the year 2027. Beyond 2027, the TO revenue requirement escalates by approximately 11 percent per year for 2028-2032, which is intended to capture additional cost to serve the increased load growth over this time period, and by approximately 4 percent per year for 2033-2045, which is based on historical trends. In addition, the adjustments for the Federal Regulatory Energy Commission (FERC)-jurisdictional balancing accounts are also included in the transmission revenue requirement: (1) Reliability Services Balancing Account (RSBA), (2) Transmission Revenue Balancing Account (TRBA), (3) Transmission Access Charge Balancing Account (TACBA), and (4) Transmission Energy Cost Recovery Amount.

Demand-Side Management (DSM) Programs

- The DSM Programs' revenue requirements forecast includes all approved and pending revenue requirement applications. This includes revenue requirements associated with Demand Response (DR), Energy Efficiency (EE), and DSM Programs.

Generation (G)

- PG&E's bundled customer generation revenue requirement is comprised of the expected bundled customer share of the forecasted cost recovery mechanisms for supply resources and the forecasted bundled portfolio costs recorded in ERRA. The supply resource cost

recovery mechanisms include the Cost Allocation Mechanism (CAM), Ongoing Competition Transition Charge (CTC), PCIA, Tree Mortality Non-bypassable Charge (TMNBC), BioMAT, and Diablo Canyon Extended Operations. ERRA costs are primarily comprised of energy and related product purchases from the CAISO, retained RA and REC purchases from CTC, PCIA, and BioMAT generation resources, RPS sales revenues, and residual RA transactions. RA, REC, and CAISO market energy price assumptions are consistent with the system portfolios described above. Further details regarding each revenue requirement can be found in PG&E's 2027 ERRA Forecast application.[52]

- As specified in the IRP filing requirements, the generation revenue requirement also includes the forecasted bundled customer share of electric distribution utility (EDU) carbon allowance auction revenues as an offset to the forecasted generation procurement costs. PG&E's forecast of these revenues are based on carbon prices from the CPUC's RESOLVE model and PG&E's annual allowance allocations for 2027 through 2030, including allowances transferred from gas utilities, consistent with the Cap and Invest regulation recently adopted by the California Air Resources Board (CARB) on May 29, 2026. Post-2030 allocations are based on PG&E's estimate of future allowance allocations using estimates of future cap adjustment factors and overall caps provided by CARB during its recent regulatory process.[53]

Other

- The revenue requirements forecast for the "Other" category includes all approved and pending revenue requirement applications. This category includes: (1) the Public Purpose Programs, excluding those considered EE, DR, DSM, TMNBC, Diablo Canyon Extended Operations, or BioMAT, (2) Wildfire Fund Charge, (3) Nuclear Decommissioning, (4) Energy Cost Recovery Amount, (5) Wildfire Hardening Charge, (6) Recovery Bond Charge and Recovery Bond Credit.

The non-generation revenue requirement forecast, comprised of Distribution, Transmission, DSM Programs, and Other is paired with the 2024 IEPR scenario's load forecast to derive the System Average Delivery Rate (SADR).[54] The SADR includes all non-Generation rate

[52] See A.26-05-007.

[53] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2026/cap_invest/nc_att%20b_2027-2030%20edu%20allocation.xlsx and https://ww2.arb.ca.gov/rulemaking/2026/cap-and-invest2026

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

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

The SABR was determined using a two-step process. First, the sum of the revenue requirements for all non-generation rate components applicable to all customers was divided by PG&E's forecasted total system sales for the respective year to determine the SADR. Second, the forecasted bundled share of generation revenue requirements was divided by PG&E bundled sales to determine bundled customers' Generation Rate.[55] The SADR and the Generation rate are summed to determine the SABR.

D. GHG Emissions and Local Air Pollutants

PG&E relied on the CSP Calculator to model GHG emissions and local air pollutants from its bundled portfolio. In accordance with the LSE GHG benchmarks published on January 16, 2026, PG&E's LSE-specific 2030, 2035, 2040, and 2045 GHG emissions benchmarks for Scenario A are 2.924 MMT, 2.443 MMT, 2.069 MMT, and 1.067 MMT, respectively.[56] For Scenarios B and C PG&E used the 2035 through 2045 GHG emissions benchmarks from Scenario A, but recommends the Commission adopt GHG emission benchmarks for 2030 consistent with likely new resource development for 2026 through 2030 and forecasted LSE load. For Scenario D, PG&E proposes modified GHG emission benchmarks of 4.46 MMT and 2.78 MMT for 2035 and 2040, respectively, based on a straight-line trajectory from modeled 2030 GHG emissions.

The CPUC's CSP calculator is also used to determine the emissions levels of three criteria pollutants for PG&E over the planning horizon. The pollutants included in the tool are $PM_{2.5}$,

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

[56] See "Load Forecasts + GHG Benchmarks" accompanying the January 16, 2026, Filing Requirements. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2026-lse-ghg-emission-benchmarks.xlsx (accessed August 3, 2026)

SO_x, and NO_x. The emissions levels of each of these pollutants from PG&E's portfolio are provided in Section III.d.i of this filing.

E. System Reliability

PG&E relied on both the RDT system reliability calculator and its Bundled SoD System RA model to calculate and assess the net system RA positions for its bundled portfolio.

During the development of PG&E's RDT for this filing, PG&E identified an area for improvement in the process. While it is important that individual LSEs demonstrate compliance with existing RA requirements, simply demonstrating compliance with existing RA requirements may not be sufficient to assure system reliability. PG&E therefore encourages that the Commission determine whether new or different metrics should be used for assessing system and local reliability given the current resource mix. For more details, refer to the "Planning for Reliability" portion of Section V: Lessons Learned.

iii. Alternate Assumptions

This section describes the assumptions PG&E used in its alternate CAISO system scenarios that differ from those published in the 2024-2026 Integrated Resource Planning (IRP) Inputs and Assumptions report and describes the impact of the assumption changes on the CAISO system level portfolio.

TABLE 2
SUMMARY OF ASSUMPTIONS BY SCENARIO

<table>
<tr><th>Label</th><th>Scenario</th><th>Source of Resource Costs</th><th>2026-2030 Average Annual Planned & RESOLVE-selected Capacity</th><th>Diablo Canyon Power Plant Online Dates</th><th>CAISO GHG Planning Targets</th></tr>
<tr><td>A</td><td>Conforming Assumptions</td><td>2026 Filing Requirements (reflect resource cost assumptions as of January 1, 2025 and does <u>not</u> include the impacts of tariffs and the OBBBA)</td><td>9.7 GW/ year</td><td rowspan="2">Online through 2024-2025</td><td rowspan="3">2030: 24.3 MMT
2035: 20.3 MMT
2040: 13.8 MMT
2045: 7.4 MMT</td></tr>
<tr><td>B</td><td>Market Informed Resource Expansion</td><td rowspan="3">26-27 TPP (reflect resource cost assumptions as of July 15, 2025 and includes the impacts of tariffs and the OBBBA)</td><td rowspan="3">6.2 GW/ year (limited to historical build rate by technology type)</td></tr>
<tr><td>C</td><td>Scenario B plus 2045 Diablo Canyon Expansion</td><td rowspan="2">Online through 2045</td></tr>
<tr><td>D</td><td>Scenario C plus Modified Interim GHG Emission Targets</td><td>2030: 45.0 MMT
2035: 33.8 MMT
2040: 18.6 MMT
2045: 7.4 MMT</td></tr>
</table>

A. Scenario A: Conforming Assumptions:

All assumptions in scenario A align with those published in the 2024-2026 IRP Inputs and Assumptions report.

B. Scenario B: Alternative #1, Market-Informed Resource Expansion:

PG&E's first alternate scenario incorporated changes to the following two assumptions:

1) Resource Costs Assumptions: The 26-27 Transmission Planning Process (26-27 TPP) resource cost assumptions were used in place of the 2026 LSE Filing Requirements' (2026 Filing Requirements) resource cost assumptions to reflect recent market conditions.[57] The 2026 Filing Requirements assumptions are based on resource cost data as of January 1, 2025 and do not capture key policy and market developments, including the July 2025 Reconciliation Bill ("OBBBA"), which repealed many Inflation Reduction Act (IRA) tax credits for renewable and clean firm resources, and impact from recent import tariffs. The 26-27 TPP assumptions incorporate these federal policy changes and reflect updated resource costs as of July 15, 2025.

   The OBBBA had a significant impact on resource costs by revising the tax credit eligibility, tightening safe harbor provisions, extending bonus depreciation, and establishing guidelines for materials imported from Foreign Entities of Concern (FEOC), and adding near-term uncertainty for projects seeking tax credits.[58] Most notably, OBBBA requires new solar and wind projects to have begun construction by July 3, 2026 to qualify for federal tax credits and imposes ongoing construction requirements to maintain eligibility. Tax credits for clean firm technologies, including geothermal and storage, remain available through 2032, with existing safe harbor and phase-out provisions preserved under the IRA.[59] Import tariffs, including Section 301 Tariffs, Fentanyl Tariffs, and Reciprocal Tariffs, have further increased resource costs by raising the price of key materials, particularly for projects which source materials from China or other Southeast Asian countries.

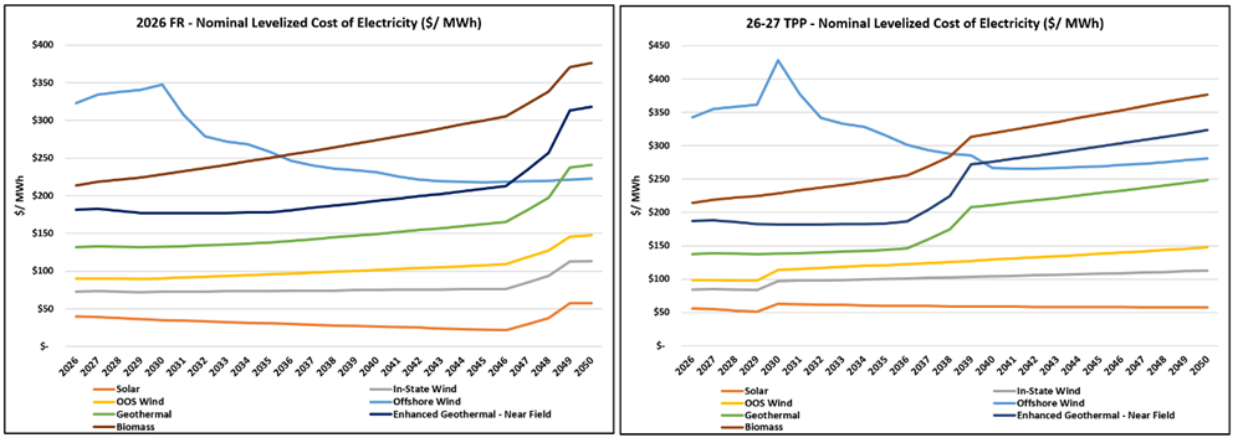
[57] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf (accessed August 3, 2026)

[58] Id.

[59] Id.

The impact of these policy and market changes can be seen in a summary of the Nominal Levelized Cost of Electricity from the 2026 Filing Requirements and 26-27 TPP below.

FIGURE 2
COMPARISON OF LEVELIZED COSTS OF ELECTRICITY (LCOE) BETWEEN 2026 FILING REQUIREMENTS AND 26-27 TRANSMISSION PLANNING PROCESS ASSUMPTIONS, NOMINAL $/MWH



2) Limited Near-Term Build Rate Assumptions: The second assumption modified in Scenario B is the build rate from 2026 through 2030. The near-term build rate for new renewable resources in the Conforming Portfolio is more than three times the average actual historical build rate between 2024-2025.[60] To understand the implications if the CAISO is unable to achieve this unprecedented level of procurement in the near-term, PG&E developed a scenario in which new build through 2030 is constrained to the 2024-2025 historical average levels by technology type, the "high water mark" in recent history. These historical averages were calculated using CPUC Resource Tracking data as of December 31, 2025.[61]

The methodology to determine the build limits was as follows. The average annual new build by technology type between 2024–2025 was used to establish an annual CAISO-wide build limit for each technology. Total new storage additions were calculated by combining

[60] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-december-2025-release.pdf.

[61] Id.

standalone storage with hybrid (solar + storage)[62] resources, resulting in a total limit of 4,496 MW of new storage capacity additions per year. This capacity was then allocated between 4-hour and 8-hour lithium-ion battery resources based on recent procurement mandates.

The 8-hour battery allocation was informed by the February 26, 2026 procurement order (D.26-02-057), which requires 2,000 MW of new NQC by 2030, 2,000 MW by 2031, and 2,000 MW by 2032 with at least 25% from long-duration energy storage.[63] Based on this requirement, 1.5 GW of 8-hour battery capacity was assumed to be procured across CAISO by 2030, corresponding to an annual build limit of 300 MW.[64] The remainder of the battery capacity is assumed to be 4-hour li-ion battery, reflecting expected market availability.

For the purpose of determining the 4-hour battery build limit, the 8-hour battery capacity was converted into 4-hour equivalent units.[65] This conversion does not affect the treatment of 8-hour batteries within their respective capacity limits, where they are maintained in their original units. Specifically, the 300 MW of 8-hour battery capacity was converted to 600 MW of 4-hour battery equivalent capacity and subtracted from the total storage limit (4,496 MW), resulting in the 4-hour battery build limit of 3,896 MW.

The total new CAISO build limit by technology was then allocated across TAC areas based on the distribution observed in the Conforming Portfolio. The percentage of new capacity assigned to each TAC by technology in the Conforming Portfolio was applied to the corresponding CAISO-wide totals.[66]

Please note that this build limit was applied in addition to the "in-development" resources forced into the Conforming Portfolio baseline by Commission Staff. "In-development"

[62] Hybrid capacity was assumed to be 100% storage since the data source does not publish a breakdown of hybrid resources by technology type.

[63] D.26-02-057, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M601/K777/601777006.PDF.

[64] Long-duration storage value is an estimate since Commission Staff had not yet completed the ELCC studies required by D.26-02-057, OP 9 by the time these portfolios were developed.

[65] The total battery capacity limit was calculated in 4-hour battery equivalent units since historical battery additions are assumed to be 4-hour battery.

[66] Given the relatively small total geothermal build and the minimal allocation to SDG&E, the SDG&E share was redistributed to PG&E and SCE to simplify modeling assumptions.

resources include 1.6 GW of out-of-state wind, 360 MW of 4-hour storage, 320 MW of geothermal, and 90 MW of solar added to the portfolio between 2026 and 2030.

Table 3 shows the CAISO-wide build rate assumption that was used for 2026 through 2030.

TABLE 3
CAISO-WIDE NEAR-TERM CUMULATIVE BUILD LIMITS BY YEAR (MW)

	2026	2027	2028	2029	2030
Solar	1,827	3,653	5,480	7,306	9,133
8-hr Li-Ion Battery	300	600	900	1,200	1,500
4-hr Li-Ion Battery	3,896	7,791	11,687	15,582	19,478
In-State Wind	144	287	431	574	718
Traditional Goethermal	21	41	62	82	103
Hydro	-	-	-	-	-
Biomass	2	4	5	7	9
Biogas	-	-	-	-	-
Total	6,188	12,376	18,563	24,751	30,939

3) Impact on the Portfolio: Applying the 26-27 TPP resource cost assumptions results in a more diversified resource mix. The 26-27 TPP assumes that with the expiration of tax credits driving increases in solar and wind costs beginning in 2030, enhanced geothermal (EGS) becomes relatively more cost-competitive and is therefore selected earlier and at higher levels. The additional clean firm resources offset the need for solar and storage resources, slightly moving the resulting portfolio towards realistic build rates.

Limiting near-term build to the historical average results in fewer overall resources selected through 2030 due to the nature of the assumption. There are fewer resources selected in each technology type, with the exception of 4-hour li-ion battery. Consistent with recent historical trends and market availability, 4-hour li-ion battery storage makes up a significant portion of new capacity additions between 2026-2030. As a result, more 4-hour li-ion battery storage is selected under this assumption (19.5 GW) compared to the Conforming Portfolio (4.4 GW). As a result, fewer LDES resources are added to the portfolio. Due to the limited new renewable capacity additions in the near-term, the 2030 GHG emissions target is not met. By 2035, total installed capacity increases rapidly to meet the 2035 GHG emissions target. See the System Modeling Results in a new section III.n for additional details.

C. Scenario C: Alternative #2, Scenario B plus 2045 Diablo Canyon Extension:

Scenario C incorporates the two assumption changes described under Scenario B (resource costs and limited near-term build) and adds a new modification to extend the operations of DCPP through 2045.

1) DCPP Extension Assumption: The 2026 Filing Requirements assumptions use the current retirement dates for DCPP, with both units 1 and 2 fully retired by 2025. To evaluate how extending DCPP operations affects total system costs and the amount of new capacity required to meet GHG emission targets, PG&E modeled a scenario in which DCPP's full operations are extended through 2045, the full 20-year license renewal period approved by the NRC in April 2026.[67]

2) Impact on the Portfolio: Between 2026-2030 when new build is fixed at the near-term build rate described above, retaining DCPP reduces GHG emissions by approximately 6 MMT annually. After 2030, when new resources can be selected beyond near-term constraints, the inclusion of DCPP displaces approximately 11 GW of primarily solar and LDES capacity. This results in approximately $1.0–$1.1 billion in net savings per year ($2.0–$2.1 billion in avoided costs, offset by $1 billion in DCPP operating costs per Commission assumptions). See the System Modeling Results in section III.n for additional details.

D. Scenario D: Alternative #3, Scenario C plus Modified Interim GHG Emission Targets

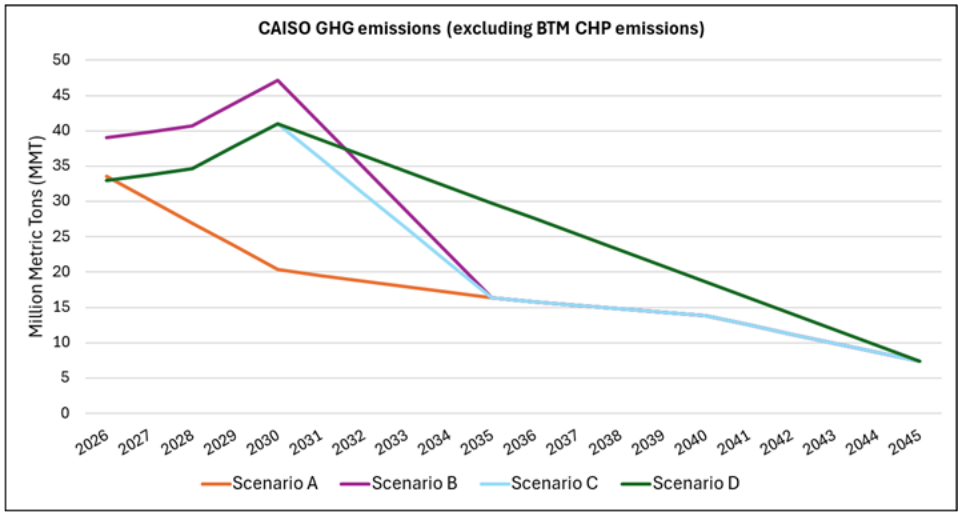
In addition to the assumptions outlined in Scenarios B and C (resource costs, limited near-term build, and DCPP extension), Scenario D also includes a modified interim GHG emission target.

1) Modified Interim GHG Emissions Target Assumption: Under this assumption, the 2030 target is set at 41 MMT, matching the emissions level achieved in Scenario C (which assumes 26-27 TPP resource costs, more feasible near-term build rate, and DCPP extended operations through 2045). Targets are then interpolated linearly from this 2030 level to the established 2045 target of 8 MMT. The chart below shows the GHG targets used by scenario.[68]

[67] https://www.nrc.gov/docs/ML2602/ML26022A077.pdf.

[68] Scenarios C and D have lower emissions in 2026 due to the inclusion of DCPP.

FIGURE 3
CAISO GHG EMISSIONS (EXCLUDING BEHIND-THE-METER (BTM) CHP EMISSIONS), MMT



2) Impact on the Portfolio: Modifying the GHG emission target in 2035 and 2040 causes the CAISO-wide emissions to increase by 13.5 MMT in 2035 and 4.8 MTM in 2040 compared to the current GHG target. However, the modified target results in 18 GW of fewer new capacity additions in 2035 and 9.5 GW in 2040. This results in up to $1.5 Billion in annual cost savings by 2035. By 2045, the portfolio catches up with Scenario C to reach the 2045 GHG emissions target, resulting in similar levels of total installed capacity. Although total installed capacity reaches levels comparable to Scenario C, Scenario D still achieves annual cost savings of $479 million in 2045 by deferring resource additions until later years when costs are projected to be lower. See the CAISO System Modeling Results in section III.n for additional details.

III. Study Results

Overall, PG&E expects that it will need to procure new incremental resources beyond its current mandated procurement to meet the IRP GHG emission targets in 2030 and beyond as well as achieve an annual GHG-free energy requirement trajectory that positions PG&E for achieving California's GHG-free energy requirements adopted in SB 100 and SB 1020. For IRP planning purposes, PG&E has identified an incremental need for between 4,644 and 7,436 MW nameplate) of resource additions by 2035 and 11,386 to 14,127 MW nameplate) by 2040 across the portfolios that were evaluated and as is shown in Tables 10 through 14.

In the following subsections, PG&E presents the following results for the portfolios created to meet the requirements for scenarios A-D.

a. Conforming and Alternative Portfolios

PG&E prepared one Conforming and three Alternative Portfolios as well as one modified Conforming portfolio to reflect the potential impacts from AB 1373 DWR procurement. These scenarios are described in more detail in section II.a.

This section includes results of PG&E's analysis to confirm that its Conforming and Alternative Portfolios meet its GHG emission, GHG-free, RPS, and RA requirements. This section also includes details of PG&E's baseline portfolio of resources (Tables 5 and 6), which includes the additional resources PG&E plans to bring online in the future to meet the procurement mandates that the Commission already authorized for PG&E (Table 7), as well as additional candidate resources that PG&E might add to meet each of the portfolios' compliance with GHG emissions, GHG-free, RPS, and RA compliance requirements (Tables 10 through 14).

i. Energy Sales Forecast

Pursuant to Commission guidance, the IRP portfolios use the published 2024 IEPR load forecast. While the 2024 IEPR forecast does take into consideration significant potential data center load growth, the CEC's more recent 2025 IEPR forecast is significantly lower primarily due to updated assumptions regarding data center load growth as well as electric vehicle, building electrification, and distributed resource development as a result of changes to federal policy.[69]

[69] Between 2028 and 2045, the 2025 IEPR Planning forecast load to serve averages 9.7% lower (32,251 GWh/yr. lower) than the 2024 IEPR Planning forecast utilized in this plan. Source: Form 1.5a in: https://efiling.energy.ca.gov/GetDocument.aspx?tn=268723&DocumentContentId=105877 (2024 IEPR) and https://efiling.energy.ca.gov/GetDocument.aspx?tn=268727 (2025 IEPR)

Table 4 shows the composition of PG&E's bundled retail sales forecast assumption for the IRP scenarios.

PG&E Unmodified Bundled Customer Demand represents PG&E's bundled sales forecast prior to adjusting for EE, DG, EVs, and electrification. PG&E's Bundled Sales represent PG&E's sales forecast after accounting for these load modifiers. PG&E Net System sales represent PG&E's total service territory sales after accounting for DA (including BART) and CCA load.

TABLE 4
CONFORMING AND ALTERNATIVE PORTFOLIOS ENERGY SALES FORECAST (GWH)

Line No.	Description	2028	2030	2035	2040	2045
1	**PG&E Unmodified Bundled Customer Demand**	30,750	36,746	41,843	43,468	44,179
2	Bundled Load Modifiers					
3	Energy Efficiency	(775)	(1,093)	(1,511)	(1,479)	(1,529)
4	Solar PV	(4,159)	(4,975)	(5,881)	(6,102)	(6,408)
5	BTM Storage Losses	41	62	96	107	121
6	Subtotal Distribution Generation	(4,118)	(4,914)	(5,785)	(5,995)	(6,287)
7	Electric Vehicles	1,861	3,677	8,503	11,942	14,298
8	Building Electrification	860	1,854	4,217	5,078	5,731
9	**PG&E Bundled Sales**	**28,579**	**36,271**	**47,268**	**53,014**	**56,391**
10	Metered PG&E Service Area Demand					
11	Direct Access	11,393	11,393	11,393	11,393	11393
12	Community Choice Aggregation	50,798	57,129	71,518	81,578	87,444
13	PG&E Net System Sales	90,770	104,793	130,179	145,985	155,228

ii. Resource Portfolio

PG&E's electric portfolio is comprised of baseline resources that have already begun deliveries or are expected to come online within the forecast horizon, as shown in Table 5, or future resource additions needed to meet the IRP's GHG emission planning requirements, as well as clean energy and system RA requirements, shown in Tables 10 through 14 for each of the identified portfolios. The total gross capacity of PG&E's baseline generating resources is shown in Table 5 and represents the total contract or utility-owned asset equivalent capacity by technology type.

TABLE 5
GROSS CAPACITY OF BASELINE PORTFOLIO RESOURCES BY TECHNOLOGY (MW)

Line No.	Resource	2028	2030	2035	2040	2045
1	Solar	4,860	6,842	6,215	2,729	1,589
2	Large Hydro	2,452	2,452	2,412	2,412	2,412
3	Nuclear	2,280	1,140	0	0	0
4	Wind	845	720	481	25	25
5	Out of State Wind	450	450	0	0	0
6	Storage					
7	Battery Storage - LSE	4,015	5,910	8,253	5,817	3,795
8	Battery Storage - CPE	10	10	10	0	0
9	Pumped Storage	1,218	1,218	1,218	1,218	1,218
10	Small Hydro	489	455	386	377	373
11	Biomass	151	197	105	61	55
12	Geothermal	40	40	368	368	368
13	Biogas	46	45	25	16	5
14	Natural Gas					
15	Natural Gas – LSE	1,984	1,586	1,586	1,586	1,586
16	Natural Gas – CPE	3,395	0	0	0	0
17	Total Gross Capacity	22,234	21,065	21,059	14,609	11,426

By 2030 PG&E expects its baseline portfolio mix to change in the following three ways: (1) no nuclear capacity as a result of the retirement of DCPP;[70] (2) LSE contracts with natural gas-fired generators forecasted to be replaced with Central Procurement Entity (CPE) contracts with non-utility owned natural gas-fired generators located in local capacity areas within PG&E's service territory;[71] and (3) growth in battery storage capacity as PG&E continues to transition to a clean, reliable supply portfolio while meeting CPUC procurement requirements. The reduction in LSE natural gas-fired capacity is due to the expiration of legacy Qualifying Facility

[70] Does not reflect five-year extension resulting from SB 846 (2021-2022 Reg. Sess.), signed into law on September 2, 2022.

[71] D.20-06-002, p. 91, OP 2, adopted PG&E as the CPE for PG&E's electric distribution service area.

(QF) contracts and contracts executed as part of either the QF/CHP Settlement Agreement or the Long-Term Procurement Plan proceeding.

To determine the supply resources available to PG&E for purposes of calculating its GHG emissions using the CPUC's CSP model, PG&E adjusts the gross capacity value for resources subject to RPS sales through Voluntary Allocation Market Offer (VAMO), large hydroelectric carbon-free energy sales, or capacity allocation through CAM. PG&E's adjusted net capacity by technology for its baseline portfolio is shown in Table 6 and represents the share of capacity from these resources available to bundled customers in the CSP model. The primary difference is between the GHG-free energy resources due to RPS energy sales as well as assumed CPE-procured natural gas resources, which would be allocated through CAM.

TABLE 6
NET BUNDLED CAPACITY SHARE OF BASELINE PORTFOLIO RESOURCES BY TECHNOLOGY (MW)

Line No.	Resource	2028	2030	2035	2040	2045
1	Solar	3,586	5,579	5,189	2,660	1,589
2	Large Hydro	2,452	2,452	2,412	2,412	2,412
3	Nuclear	332	189	0	0	0
4	Wind	635	510	273	25	25
5	Out of State Wind	450	450	0	0	0
6	Storage					
7	Battery Storage - LSE	3,796	5,699	8,046	5,651	3,679
8	Battery Storage - CPE	3	3	4	0	0
9	Pumped Storage	1,218	1,218	1,218	1,218	1,218
10	Small Hydro	366	332	282	253	373
11	Biomass	84	129	47	61	55
12	Geothermal	32	32	368	368	368
13	Biogas	36	34	20	11	5
14	Natural Gas					
15	Natural Gas - LSE	1,984	1,586	1,586	1,586	1,586
16	Natural Gas - CPE	1,069	0	0	0	0
17	Total Bundled Capacity	16,042	18,212	19,444	14,244	11,309

iii. Resource Additions

PG&E's resource additions are broken out between baseline additions,[72] shown in Table 7, and incremental resource additions for meeting the two Conforming portfolios and three alternative portfolios, shown in Tables 10 through 14. The baseline resource additions in Table 7 reflect the resources PG&E plans to add 'as a result of' procurement mandates already authorized by the Commission and are the same for all portfolios. This includes resources that have already been contracted with and are not yet online, and mandated or authorized resources PG&E had not yet contracted for prior to the submittal of its 2026 IRP. The amounts shown are total resource capacities, not reflecting any capacity allocations for CAM cost recovery to the extent it is applicable. Table 7 also does not include any investments by customers or third parties in DERs or investments in EE, which are modeled as load modifiers based on the IEPR forecast values.

[72] Defined as projects expected to begin deliveries on September 1, 2026 or later.

TABLE 7
BASELINE CUMULATIVE NEW RESOURCE ADDITIONS (MW)

Line No.	Technology	2028	2030	2040	2045
1	**Biogas**				
2	ReMAT	0	1	1	1
3	**Biomass**				
4	SB1122/BioMAT	3	3	3	3
5	ReMAT	0	46	46	46
6	**Biomass Subtotal**	**2**	**50**	**50**	**50**
7	**Wind**				
8	ReMAT	0	25	25	25
9	**Solar PV**				
10	ReMAT	25	25	25	25
11	GTSR/DAC	6	33	33	33
12	IRP Procurement Order[73]	950	2,458	2,458	1,508
13	**Geothermal**				
14	IRP Procurement Order	18	18	368	368
15	**Small Hydro**				
16	ReMAT	1	1	1	1
17	**Large Hydro-Pumped Storage**				
18	UOG Capital Upgrade	0	120	180	180
19	**Storage**				
20	IRP Procurement Order	1,300	2,808	4,913	3,613
21	Total Portfolio Resource Additions	2,303	5,539	8,054	5,804

Baseline portfolio additions are expected as a result of the following activities:

a) Existing Contracts: As a result of procurement done through PG&E's ReMAT and BioMAT programs as well as the CPUC's 2021 and 2023 IRP Procurement Track decisions, PG&E has executed contracts with solar PV, biomass, geothermal, and

[73] IRP procurement order classification in Table 5 includes procurement related to all IRP procurement orders since 2021, including D.21-06-035, D.23-02-040 and D.26-02-057.

battery energy storage system resources that are expected to begin delivering energy for PG&E's bundled customers by 2026.[74]

b) RPS Resource Procurement: PG&E forecasts procurement of additional bioenergy, solar, and wind resources through the Commission's existing mandated procurement programs (e.g., BioMAT, ReMAT, GTSR).[75] Additionally, PG&E anticipates it will procure geothermal resources to fulfill its remaining 2021 Mid-Term Reliability requirements.

c) 2026 IRP Procurement Order: PG&E forecasts procurement to fulfill requirements established by the Commission in D.26-02-057. Procurement to meet this requirement may include a subset or both RPS-eligible and energy storage resources.

After accounting for these baseline resource additions as well as existing resources in PG&E's portfolio, Tables 10 through 14 show the additional resources that PG&E identified would be needed to meet its various bundled IRP planning compliance obligations, including GHG emission targets, for its two Conforming portfolios and three alternative portfolios. The set of candidate resources assumed to be available to PG&E for its new resource addition process are constrained to be consistent with the resource additions identified in each scenario's system portfolio build as show in Section III.n – CAISO System Modeling Results.

Tables 8 and 9 below compare the CAISO-system-level resource mix from the CPUC's 25-26 TPP with PG&E's bundled portfolio new resource technology mix from Scenario A.

[74] CPUC ordered 2021 and 2023 IRP Mid-Term Reliability Procurement through D.21-06-035 and D.23-02-040, respectively.

[75] These mandated procurement programs are described in PG&E's Draft 2026 Renewable Energy Procurement Plan, https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=877764 (accessed August 3, 2026)

TABLE 8
NEW RESOURCE TECHNOLOGY MIX FROM 2025 – 2026 TPP

Line No.	Technology	2030	2035	2040	2045
1	Geothermal	4%	3%	2%	1%
2	Biomass	1%	0%	0%	0%
3	In-State Wind	13%	13%	8%	7%
4	Out-of-State Wind	12%	14%	11%	12%
5	Offshore Wind	0%	7%	5%	3%
6	Solar	37%	32%	45%	47%
7	Li-ion Battery (4 hr)	29%	25%	16%	12%
8	Li-ion Battery (8 hr)	3%	4%	12%	16%
9	Pumped Hydro Storage (12 hr)	1%	1%	1%	1%
10	Other LDES (8-24 hr)	1%	1%	1%	0%

TABLE 9
BUNDLED PORTFOLIO NEW RESOURCE TECHNOLOGY MIX FROM SCENARIO A

Line No.	Technology	2030	2035	2040	2045
1	Geothermal	5%	3%	2%	2%
2	Biomass	0%	0%	0%	0%
3	In-State Wind	2%	7%	7%	7%
4	Out-of-State Wind	12%	7%	18%	14%
5	Offshore Wind	0%	0%	0%	0%
6	Solar	59%	58%	52%	52%
7	Li-ion Battery (4 hr)	9%	5%	3%	4%
8	Li-ion Battery (8 hr)	13%	15%	9%	14%
9	Pumped Hydro Storage (12 hr)	0%	4%	9%	6%
10	Other LDES (8-24 hr)	0%	0%	0%	0%

TABLE 10
ADDITIONAL PROCUREMENT FOR SCENARIO A PORTFOLIO (MW)

Line No.	Technology	2028	2030	2035	2040	2045
1	**Solar PV**					
2	NorCal	0	702	1,375	1,756	3,016
3	SoCal	0	970	1,987	3,470	5,555
4	Existing	0	9	910	2,418	3,098
5	**Wind**					
6	NorCal	0	0	208	446	446
7	SoCal	0	56	182	271	717
8	Existing	0	11	413	730	736
9	**Out of State Wind**					
10	Idaho	0	65	65	65	65
11	New Mexico	0	174	174	658	1,219
12	Wyoming	0	89	189	1,083	1,083
13	Existing	0	21	198	308	308
14	**Geothermal**					
15	New	0	144	196	196	328
16	Existing	0	0	10	10	84
17	**Biomass**					
18	Existing	0	0	16	24	24
19	**Small Hydro**					
20	Existing	0	0	8	8	8
21	**Storage**					
22	4-hr Battery Storage	0	263	263	263	710
23	Existing 4-hr Battery Storage	0	0	108	642	1,570
24	8-hr Battery Storage	0	383	890	890	2,243
25	Pumped Storage	0	0	243	889	978
26	**Natural Gas**					
27	Local CPE Allocation	0	1,904	1,909	1,976	2,009
28	**Total Portfolio Resource Additions**	**0**	**4,790**	**9,345**	**16,103**	**24,195**

TABLE 11
ADDITIONAL PROCUREMENT FOR SCENARIO B PORTFOLIO (MW)

Line No.	Technology	2028	2030	2035	2040	2045
1	**Solar PV**					
2	NorCal	0	0	1,004	1,679	2,626
3	SoCal	0	0	1,821	2,705	5,519
4	Existing	0	0	900	2,409	3,089
5	**Wind**					
6	NorCal	0	0	105	703	703
7	SoCal	0	0	112	427	948
8	Existing	0	0	403	719	725
9	**Out of State Wind**					
10	Idaho	0	0	0	0	237
11	New Mexico	0	0	235	742	1,374
12	Wyoming	0	0	240	1,232	1,232
13	Existing	0	0	178	288	288
14	**Geothermal**					
15	New	0	0	410	410	410
16	Existing	0	0	10	10	84
17	**Biomass**					
18	Existing	0	0	16	24	24
19	**Small Hydro**					
20	Existing	0	0	8	8	8
21	**Storage**					
22	4-hr Battery Storage	0	0	354	354	354
23	Existing 4-hr Battery Storage	0	0	108	642	1,570
24	8-hr Battery Storage	0	0	439	439	1,947
25	Pumped Storage	0	0	279	279	279
26	**Natural Gas**					
27	Local CPE Allocation	0	1,904	1,909	1,976	2,009
28	**Total Portfolio Resource Additions**	**0**	**1,904**	**8,531**	**15,045**	**23,426**

TABLE 12
ADDITIONAL PROCUREMENT FOR SCENARIO C PORTFOLIO (MW)

Line No.	Technology	2028	2030	2035	2040	2045
1	**Solar PV**					
2	NorCal	0	0	520	1,255	2,634
3	SoCal	0	0	1,300	2,388	5,036
4	Existing	0	0	900	2,409	3,089
5	**Wind**					
6	NorCal	0	0	97	662	662
7	SoCal	0	0	92	404	739
8	Existing	0	0	403	719	725
9	**Out of State Wind**					
10	Idaho	0	0	0	53	230
11	New Mexico	0	0	193	694	1,363
12	Wyoming	0	0	198	1,073	1,220
13	Existing	0	0	178	288	288
14	**Geothermal**					
15	New	0	0	302	302	302
16	Existing	0	0	10	10	84
17	**Biomass**					
18	Existing	0	0	16	24	24
19	**Small Hydro**					
20	Existing	0	0	8	8	8
21	**Storage**					
22	4-hr Battery Storage	0	0	291	1,027	1,027
23	Existing 4-hr Battery Storage	0	0	108	642	1,570
24	8-hr Battery Storage	0	0	164	284	1,822
25	Pumped Storage	0	0	229	229	229
26	**Natural Gas**					
27	Local CPE Allocation	0	1,904	1,909	1,976	2,009
28	**Total Portfolio Resource Additions**	**0**	**1,904**	**6,919**	**14,446**	**23,060**

TABLE 13
ADDITIONAL PROCUREMENT FOR SCENARIO D PORTFOLIO (MW)

Line No.	Technology	2028	2030	2035	2040	2045
1	**Solar PV**					
2	NorCal	0	0	529	1,052	2,435
3	SoCal	0	0	1,240	1,841	6,094
4	Existing	0	0	900	2,409	3,089
5	**Wind**					
6	NorCal	0	0	0	396	396
7	SoCal	0	0	129	300	300
8	Existing	0	0	403	719	725
9	**Out of State Wind**					
10	Idaho	0	0	0	0	170
11	New Mexico	0	0	50	518	1,130
12	Wyoming	0	0	0	711	812
13	Existing	0	0	178	288	288
14	**Geothermal**					
15	New	0	0	354	354	354
16	Existing	0	0	10	10	84
17	**Biomass**					
18	Existing	0	0	16	24	24
19	**Small Hydro**					
20	Existing	0	0	8	8	8
21	**Storage**					
22	4-hr Battery Storage	0	0	406	1,718	1,718
23	Existing 4-hr Battery Storage	0	0	108	642	1,570
24	8-hr Battery Storage	0	0	0	84	2,364
25	Pumped Storage	0	0	313	313	313
26	**Natural Gas**					
27	Local CPE Allocation	0	1,904	1,909	1,976	2,009
28	**Total Portfolio Resource Additions**	**0**	**1,904**	**6,553**	**13,362**	**23,882**

TABLE 14
ADDITIONAL PROCUREMENT FOR SCENARIO E PORTFOLIO (MW)

Line No.	Technology	2028	2030	2035	2040	2045
1	**Solar PV**					
2	NorCal	0	702	1,140	1,389	2,440
3	SoCal	0	970	1,633	2,599	4,339
4	Existing	0	9	910	2,418	3,098
5	**Wind**					
6	NorCal	0	0	136	291	291
7	SoCal	0	56	138	196	568
8	Existing	0	11	413	730	736
9	**Out of State Wind**					
10	Idaho	0	65	65	65	65
11	New Mexico	0	174	174	489	958
12	Wyoming	0	89	154	737	737
13	Existing	0	21	198	308	308
14	**Geothermal**					
15	New	0	144	178	178	288
16	Existing	0	0	10	10	84
17	**Biomass**					
18	Existing	0	0	16	24	24
19	**Small Hydro**					
20	Existing	0	0	8	8	8
21	**Storage**					
22	4-hr Battery Storage	0	263	263	263	636
23	Existing 4-hr Battery Storage	0	0	108	642	1,570
24	8-hr Battery Storage	0	383	713	713	1,842
25	Pumped Storage	0	0	159	579	654
26	**Natural Gas**					
27	Local CPE Allocation	0	1,904	1,909	1,976	2,009
28	**Total Portfolio Resource Additions**	**0**	**4,790**	**8,326**	**13,615**	**20,654**

iv. Resource Sales

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

a) **RPS Sales:** On May 20, 2021, the Commission adopted Decision D.21-05-030, creating significant regulatory changes in how PG&E will be able to manage its RPS-eligible portfolio. VAMO was adopted for PCIA-eligible resources and applies to PG&E's resources that are eligible for PCIA cost recovery, which is a majority of PG&E's RPS portfolio. Under VAMO, PCIA-eligible LSEs had an option to receive an allocation of RPS attributes from the IOUs' PCIA-eligible resources based on each LSE's vintaged load forecast relative to the total PCIA-eligible vintaged load forecast. Declined allocations were offered for sale by the IOUs through a market offer process. PG&E retains 100 percent of the bundled service customer share of the expected RPS-eligible generation subject to VAMO.

b) **Carbon-Free Energy Sales:** In May 2020, the Commission adopted Res.E-5046 to give LSEs within PG&E's TAC area the option to receive a pro-rata allocation of the GHG-free attributes associated with PG&E's large hydroelectric carbon-free resources for the remainder of 2020. The Commission subsequently gave PG&E the option to retain the entirety of its large hydroelectric volumes in three-year periods with elections made in its ERRA Forecast Application for the first three-year period. PG&E made available and executed allocation agreements with LSEs within PG&E's TAC area for the period of 2025-2027. For its 2026 IRP, PG&E assumes it will retain the entirety of the large hydro volumes beginning in 2028 and beyond, though PG&E will officially make an election for the period of 2028-2030 in its 2028 ERRA Forecast. The assumption of retention in this IRP is not a commitment for future periods.

v. Clean System Power Model Energy Volumes

To calculate PG&E's bundled portfolio GHG emissions for each of the five portfolios using the CPUC's CSP model, PG&E combined the forecasted energy and capacity inputs from the baseline resources presented in Table 5 with the respective resource additions presented in Tables 10 through 14. The resulting forecasted energy volumes in each of the three bundled CSP model portfolios are shown in Tables 15 through 19, with each resulting in PG&E meeting its bundled IRP GHG emissions planning targets as specified in each scenario assumption.

TABLE 15
SCENARIO A PORTFOLIO CSP ENERGY SUPPLY (GWH)

Line No.	Resource	2028	2030	2035	2040	2045
1	**Demand Inputs**					
2	Managed Retail Sales	28,579	36,271	47,268	53,014	56,391
3	Behind-The-Meter PV	4,159	4,975	5,881	6,102	6,408
4	**Supply Inputs**					
5	Large Hydro	8,058	8,046	7,936	7,965	7,934
6	Imported Hydro	2,024	2,304	2,455	2,461	2,469
7	Asset Controlling Supplier	0	0	0	0	0
8	Nuclear	0	0	0	0	0
9	Biogas	221	214	122	69	16
10	Biomass	783	812	698	412	398
11	Geothermal	136	1,342	4,453	4,452	5,943
12	Small Hydro	733	684	562	476	832
13	**Wind Resources**					
14	Wind Baseline California	1,770	1,362	810	73	73
15	Wind New PG&E	0	0	494	1,059	1,059
16	Wind New SCE SDG&E	0	166	1,436	2,409	3,547
17	Wind Pacific Northwest	0	146	471	471	471
18	Wind Wyoming	0	372	822	3,853	3,853
19	Wind New Mexico	0	575	575	2,529	4,379
20	Wind Offshore Morro Bay	0	0	0	0	0
21	Wind Offshore Humboldt	0	0	0	0	0
22	**Solar Resources**					
23	Solar Baseline California	8,300	12,468	15,246	14,395	12,653
24	Solar New PG&E	0	1,994	3,835	4,813	8,236
25	Solar New SCE SDG&E	0	2,908	5,855	10,111	16,046
26	Solar Distributed	0	0	0	0	0
27	**Storage & DR**[76]					
28	Shed DR (MW)	301	324	414	431	431
29	Pumped Storage (MW)	1,212	1,212	1,455	2,101	2,190
30	Battery Storage	10,059	28,684	42,314	34,014	43,096
31	**Total CSP Supply Input**	**32,085**	**62,076**	**88,083**	**89,564**	**111,005**

[76] Storage and DR section includes CSP supply inputs as reported in RDT. Shed DR and Pumped Storage are reported in MWs while Battery Storage is reported in 'Energy Capacity', which multiplies storage duration by storage capacity.

TABLE 16
SCENARIO B PORTFOLIO CSP ENERGY SUPPLY (GWH)

Line No.	Resource	2028	2030	2035	2040	2045
1	**Demand Inputs**					
2	Managed Retail Sales	28,579	36,271	47,268	53,014	56,391
3	Behind-The-Meter PV	4,159	4,975	5,881	6,102	6,408
4	**Supply Inputs**					
5	Large Hydro	8,058	8,046	7,936	7,965	7,934
6	Imported Hydro	2,024	2,304	2,455	2,461	2,469
7	Asset Controlling Supplier	0	0	0	0	0
8	Nuclear	0	0	0	0	0
9	Biogas	221	214	122	69	16
10	Biomass	783	812	698	412	398
11	Geothermal	136	232	6,078	6,069	6,555
12	Small Hydro	733	681	558	476	832
13	**Wind Resources**					
14	Wind Baseline California	1,770	1,137	810	73	73
15	Wind New PG&E	0	0	249	1,670	1,670
16	Wind New SCE SDG&E	0	0	283	1,077	2,393
17	Wind Pacific Northwest	0	0	0	0	531
18	Wind Wyoming	0	0	815	4,177	4,177
19	Wind New Mexico	0	0	775	2,443	4,527
20	Wind Offshore Morro Bay	0	0	0	0	0
21	Wind Offshore Humboldt	0	0	0	0	0
22	**Solar Resources**					
23	Solar Baseline California	8,300	10,268	11,796	11,025	9,375
24	Solar New PG&E	0	0	2,821	4,648	7,195
25	Solar New SCE SDG&E	0	0	5,398	7,889	16,044
26	Solar Distributed	0	0	0	0	0
27	**Storage & DR**					
28	Shed DR (MW)	301	324	414	431	431
29	Pumped Storage (MW)	1,212	1,212	1,491	1,491	1,491
30	Battery Storage	10,059	24,573	39,505	33,341	45,588
31	**Total CSP Supply Input**	**32,085**	**48,266**	**80,299**	**83,796**	**109,775**

TABLE 17
SCENARIO C PORTFOLIO CSP ENERGY SUPPLY (GWH)

Line No.	Resource	2028	2030	2035	2040	2045
1	**Demand Inputs**					
2	Managed Retail Sales	28,579	36,271	47,268	53,014	56,391
3	Behind-The-Meter PV	4,159	4,975	5,881	6,102	6,408
4	**Supply Inputs**					
5	Large Hydro	8,058	8,046	7,936	7,965	7,934
6	Imported Hydro	2,024	2,304	2,455	2,461	2,469
7	Asset Controlling Supplier	0	0	0	0	0
8	Nuclear	2,273	2,457	2,622	2,820	2,570
9	Biogas	221	214	122	69	16
10	Biomass	783	812	698	412	398
11	Geothermal	136	232	5,258	5,253	5,753
12	Small Hydro	733	681	558	476	832
13	**Wind Resources**					
14	Wind Baseline California	1,770	1,137	810	73	73
15	Wind New PG&E	0	0	231	1,571	1,571
16	Wind New SCE SDG&E	0	0	233	1,018	1,864
17	Wind Pacific Northwest	0	0	0	119	514
18	Wind Wyoming	0	0	670	3,639	4,139
19	Wind New Mexico	0	0	637	2,288	4,491
20	Wind Offshore Morro Bay	0	0	0	0	0
21	Wind Offshore Humboldt	0	0	0	0	0
22	**Solar Resources**					
23	Solar Baseline California	8,300	10,268	12,774	11,979	10,305
24	Solar New PG&E	0	0	1,446	3,477	7,270
25	Solar New SCE SDG&E	0	0	3,821	6,955	14,638
26	Solar Distributed	0	0	0	0	0
27	**Storage & DR**					
28	Shed DR (MW)	301	324	414	431	431
29	Pumped Storage (MW)	1,212	1,212	1,441	1,441	1,441
30	Battery Storage	10,059	24,573	37,057	34,792	47,279
31	**Total CSP Supply Input**	**34,358**	**50,723**	**77,329**	**85,368**	**112,116**

TABLE 18
SCENARIO D PORTFOLIO CSP ENERGY SUPPLY (GWH)

Line No.	Resource	2028	2030	2035	2040	2045
1	**Demand Inputs**					
2	Managed Retail Sales	28,579	36,271	47,268	53,014	56,391
3	Behind-The-Meter PV	4,159	4,975	5,881	6,102	6,408
4	**Supply Inputs**					
5	Large Hydro	8,058	8,046	7,936	7,965	7,934
6	Imported Hydro	2,024	2,304	2,455	2,461	2,469
7	Asset Controlling Supplier	0	0	0	0	0
8	Nuclear	2,273	2,457	2,622	2,820	2,570
9	Biogas	221	214	122	69	16
10	Biomass	783	812	698	412	398
11	Geothermal	136	232	5,649	5,643	6,136
12	Small Hydro	733	681	558	476	832
13	**Wind Resources**					
14	Wind Baseline California	1,770	1,137	810	73	73
15	Wind New PG&E	0	0	0	941	941
16	Wind New SCE SDG&E	0	0	324	756	756
17	Wind Pacific Northwest	0	0	0	0	381
18	Wind Wyoming	0	0	0	2,410	2,754
19	Wind New Mexico	0	0	165	1,706	3,721
20	Wind Offshore Morro Bay	0	0	0	0	0
21	Wind Offshore Humboldt	0	0	0	0	0
22	**Solar Resources**					
23	Solar Baseline California	8,300	10,268	11,796	11,025	9,375
24	Solar New PG&E	0	0	1,472	2,906	6,724
25	Solar New SCE SDG&E	0	0	3,644	5,336	17,825
26	Solar Distributed	0	0	0	0	0
27	**Storage & DR**					
28	Shed DR (MW)	301	324	414	431	431
29	Pumped Storage (MW)	1,212	1,212	1,525	1,525	1,525
30	Battery Storage	10,059	24,573	36,201	35,954	54,373
31	**Total CSP Supply Input**	**34,358**	**50,723**	**74,454**	**80,955**	**117,278**

TABLE 19
SCENARIO E PORTFOLIO CSP ENERGY SUPPLY (GWH)

Line No.	Resource	2028	2030	2035	2040	2045
1	**Demand Inputs**					
2	Managed Retail Sales	28,579	36,271	47,268	53,014	56,391
3	Behind-The-Meter PV	4,159	4,975	5,881	6,102	6,408
4	**Supply Inputs**					
5	Large Hydro	8,058	8,046	7,936	7,965	7,934
6	Imported Hydro	2,024	2,304	2,455	2,461	2,469
7	Asset Controlling Supplier	0	0	0	0	0
8	Nuclear	0	0	0	0	0
9	Biogas	221	214	122	69	16
10	Biomass	783	812	698	412	398
11	Geothermal	136	1,342	11,682	13,672	7,458
12	Small Hydro	733	684	562	476	832
13	**Wind Resources**					
14	Wind Baseline California	1,770	1,362	810	73	73
15	Wind New PG&E	0	0	454	817	817
16	Wind New SCE SDG&E	0	166	399	544	1,486
17	Wind Pacific Northwest	0	146	111	111	111
18	Wind Wyoming	0	372	542	2,487	2,487
19	Wind New Mexico	0	575	436	1,457	3,007
20	Wind Offshore Morro Bay	0	0	0	1,961	1,956
21	Wind Offshore Humboldt	0	0	0	0	3,103
22	**Solar Resources**					
23	Solar Baseline California	8,300	12,468	11,821	11,049	9,399
24	Solar New PG&E	0	1,994	3,212	3,821	6,693
25	Solar New SCE SDG&E	0	2,908	4,924	7,627	12,619
26	Solar Distributed	0	0	0	0	0
27	**Storage & DR**					
28	Shed DR (MW)	301	324	414	431	431
29	Pumped Storage (MW)	1,212	1,212	1,866	1,866	1,866
30	Battery Storage	10,059	28,684	41,333	35,169	45,876
31	**Total CSP Supply Input**	**32,085**	**62,076**	**87,497**	**90,172**	**106,732**

b. Conforming and Alternative Portfolios for IRP Compliance

PG&E is submitting two Conforming Portfolios[77] in this plan, meeting the requirements described in Section III.b of the IRP filing requirements while also submitting three Alternative Portfolios to demonstrate the customer affordability benefits associated with further extending Diablo Canyon and modifying the GHG emission targets for 2030, 2035, and 2040. These alternative portfolios build on a market-informed resource expansion portfolio which establishes a baseline based on PG&E's recommended assumptions for new resource technology costs and new resource annual build rates through 2030. PG&E is also submitting the required Conforming Portfolio with DWR additions.

As described below, PG&E's Conforming and Alternative Portfolios meet the following requirements of SB 350, as codified in Public Utilities Code Section 454.52(a)(1):

454.52(a)(1)(A): As shown in Section III.c, PG&E's Conforming Portfolios meet the assigned LSE GHG planning benchmarks for PG&E in 2030, 2035, 2040, and 2045 while Alternative Portfolios for Scenarios B and C meet the 2035, 2040, and 2045 benchmarks and Scenario D meets proposed modified GHG planning benchmarks for 2035 and 2040 before achieving the Conforming benchmark for 2045.

[77] Results for Scenario E are limited to the resource additions presented in Table 14.

454.52(a)(1)(B): Figure 4 shows how PG&E's Portfolios meet the LSE RPS compliance requirements for the IRP study years 2028, 2030, 2035, 2040, and 2045. In each portfolio, PG&E's RPS position continues to increase beyond 2030 as a result of resource additions to meet the IRP GHG emission planning targets and California's clean energy content requirements adopted in SB 100 and SB 1020. Figure 5 shows how PG&E's Portfolios meet the LSE GHG-free energy content compliance requirements for IRP study years 2035, 2040**,** and 2045. 2028 and 2030 are included as well, though 2035 is the first compliance year adopted in SB 1020. For Scenarios C and D, RPS compliance needs in 2031 through 2033 exceed the linear build rate of resources planned to meet 2035 emissions targets, so an accelerated build rate is forced into the modeling, resulting in elevated clean positions in these scenarios and years.

FIGURE 4
RPS POSITION

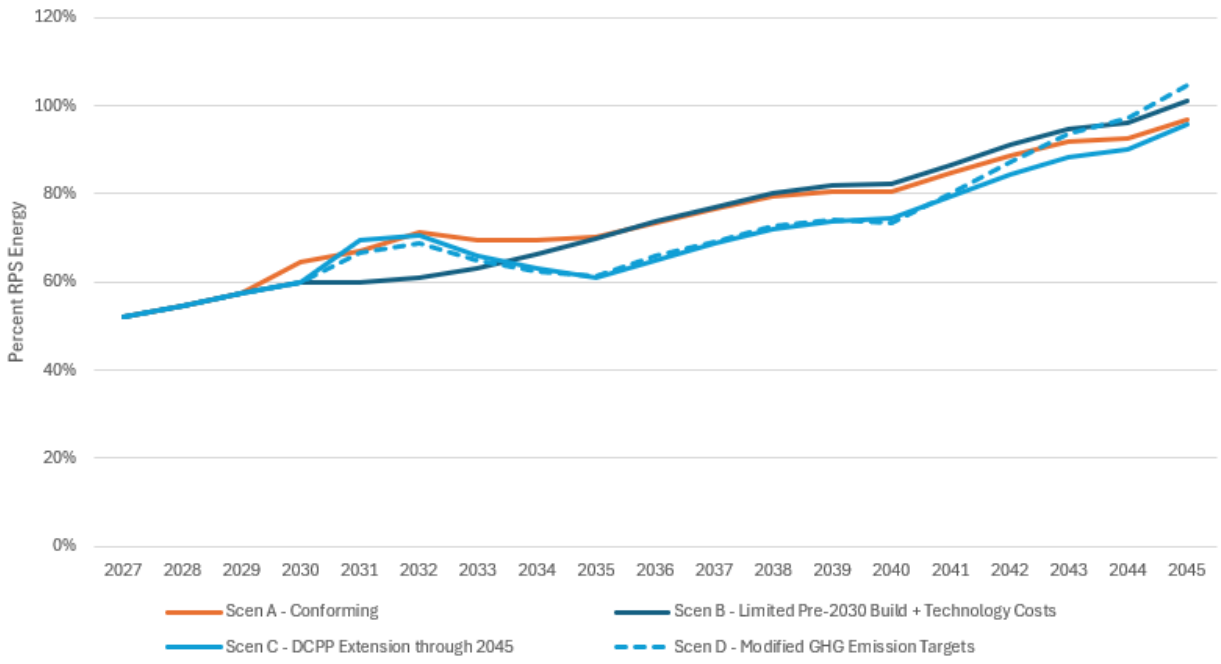
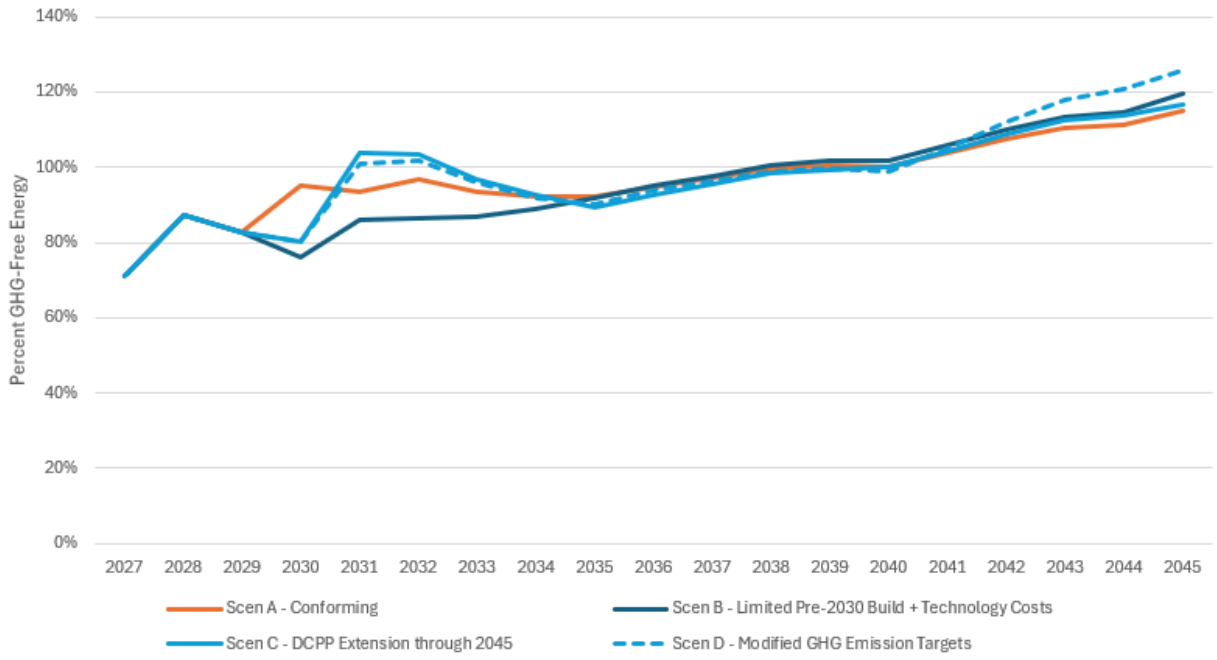


FIGURE 5
PORTFOLIO GHG-FREE POSITION



454.52(a)(1)(C): The revenue requirements and associated bundled generation rates for PG&E's portfolios are shown in Section III.e. These rates reflect the net impact from PG&E's baseline resource portfolio, which is comprised of existing contracts and utility owned resources already approved as reasonable by the Commission as well as additional Commission-ordered procurement, and a mix of future resource additions that meet the bundled portfolio planning and compliance requirements based on PG&E's planned resource addition process.

454.52(a)(1)(D): PG&E's portfolios minimize ratepayer bills to the extent feasible through the IRP process. Specifically, PG&E's portfolios do not include any incremental procurement beyond what PG&E expects is needed to meet GHG emission, GHG-free, RPS, and RA requirements through 2045, with resource additions incorporated gradually over time.

454.52(a)(1)(E): Per the Commission's IRP filing requirements in Section III.f, PG&E's portfolios demonstrate meeting the required RDT system RA reliability requirements as well as the SoD System RA compliance requirements. For local reliability, PG&E assumes that the CPE will procure at least capacity from thermal resources assumed to be operating through 2045 and located in PG&E local capacity areas to ensure local reliability requirements are met. For purposes of calculating PG&E's system RA position in Section III.f, PG&E includes its bundled LSE

load share of these local resources. PG&E also includes planned future short-term purchases based on its bundled LSE load share from available existing thermal resources not already identified for use towards meeting the local reliability requirements.

454.52(a)(1)(F): On August 17, 2017, PG&E informed the Commission of election to comply early with the long-term contracting requirements in subsection (b), starting with the 2017–2020 RPS compliance period. PG&E will continue to comply going forward, as will be reported in its RPS compliance reports.

454.52(a)(1)(G): PG&E's portfolios include a diverse set of resources that provide support to CAISO system reliability. For 2030, PG&E's Portfolios provide 56 percent, 57 percent, 56 percent, and 56 percent of their September RA requirements from flexible, non-emitting resources, including hydroelectric, pumped storage, and battery storage across Scenarios A, B, C, and D, respectively.

454.52(a)(1)(H): PG&E's Action Plan includes extensive demand side procurement activities to support demand side energy management and continuing growth in demand-side energy resources, including energy efficiency, rooftop solar generation, EVs, building electrification, and expanded demand response participation in both CAISO and Commission DR programs.

454.52(a)(1)(I): PG&E's Action Plan includes a broad range of programs focused on DACs. These programs include electrification and fuel switching pilots, community solar programs, and clean transportation programs focused on DACs. Additionally, as discussed in the filing, PG&E actively pursues procurement options to improve air quality in DACs.

454.52(a)(1)(J): PG&E's portfolios include a diverse set of resources that provide support to CAISO system reliability, including Portfolio E which reflects PG&E's allocation of DWR procurement provided by the Commission.

Comparison to 2022 LSE IRP:

PG&E's conforming 8MMT by 2045 portfolio, Portfolio A, varies from the 25 MMT by 2035 Portfolio submitted as part of its 2022 LSE IRP in several key areas. The technology mix of resource additions needed to meet GHG emissions and reliability needs for 2030 and beyond is more diverse in this IRP plan when compared to 2022 which was made up of solar, wind and battery storage resources. Resources added in this 2026 plan include a mix of existing resources PG&E has identified as being available throughout the forecast horizon, as well as solar, wind, geothermal, battery storage and pumped storage. This difference was driven mainly by system modeling results as well as changes in PG&E's bundled modeling methodology for bundled resource additions.

In addition to differences in resource mix, PG&E's 2026 LSE IRP plan has resource additions to meet its SoD RA reliability requirements, new since the 2022 IRP. In some years, SOD compliance requires the addition of more battery storage than otherwise included for GHG emissions requirements.

c. GHG Emissions Results

i. CSP Model Resource Assumptions

a) **GHG-Free Energy Supply:** The GHG-free energy forecast used in PG&E's CSP portfolio is shown in Tables 15 through 19 and consists of PG&E's baseline resources shown in Table 6 as well as the identified additions to meet the IRP planning constraints shown in Tables 10 through 14 for the four presented portfolios. PG&E's portfolio does include non-Portfolio Content Category (PCC) 1 out-of-state (OOS) wind resources, which have been excluded from providing a GHG benefit in the CSP calculator.

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

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

d) **Energy Storage (Capacity Attributes):** PG&E has several contracts with energy storage assets where PG&E is purchasing all of the capacity and counting attributes, but not directly purchasing any energy revenues. PG&E included these resources in its CSP supply portfolio, which aligns with the Commission's CSP portfolio guidance.[78]

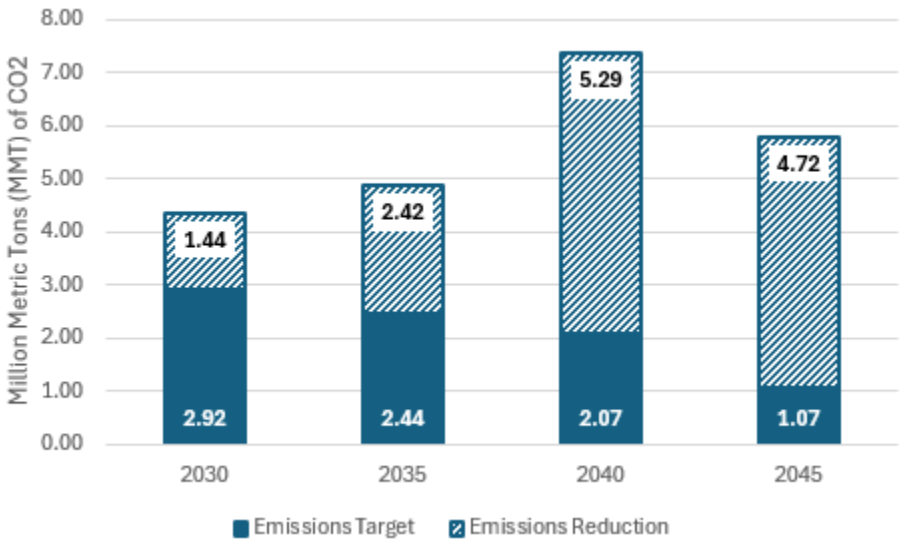
[78] Integrated Resource Planning (R.20-05-003) 2022 IRP Filings, Filing Requirements' Questions and Answers, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2022-irp-cycle-events-and-materials/2022-filling-requirement-qav2.pdf (accessed August 3, 2026)

e) **Front-of-the-Meter CHP:** The current CSP model is set up to calculate each LSE's front-of-the-meter CHP emissions based on their respective load share. This does not reflect actual individual LSE's CHP retirements and assumes there is no reduction in system CHP capacity until after 2030 as California moves towards meeting its SB 100 goals. While the Commission's assumption on CHP emissions helps to simplify calculations, it may fail to account for changes individual LSEs are making to reduce CAISO system CHP capacity and consequently GHG emissions.

ii. Scenario GHG Emission Results

As described above, PG&E will need to add additional resources to its baseline portfolio to meet its GHG emission benchmarks for all scenarios and emissions requirement years where the GHG benchmarks are enforced. This includes 2030 in the Conforming scenario given 2035 is the first GHG emission target year for scenarios B, C, and D. Figure 6 shows the initial gross baseline GHG emission totals as well as the net GHG emissions for each study year for the Conforming scenario based on the resource additions presented in Table 10.

FIGURE 6
CONFORMING SCENARIO CSP GHG EMISSION RESULTS (MMT)



The sum of the solid and shaded sections for each study year represents the initial gross baseline GHG emissions before any resources incremental to PG&E's baseline portfolio are added. For example, for the Conforming scenario in 2035, the initial gross baseline GHG emissions are 4.86 MMT. The shaded section of each column represents the GHG emission reductions resulting from the incremental new resource additions. In the Conforming scenario

above, this value is 2.42 MMT for 2035. Finally, the solid section of each column represents the final GHG emissions totals. In the previous example, this is the initial gross baseline GHG emissions minus GHG reductions due to the addition of new resources, a value of 2.44 MMT. For Alternative scenarios B, C, and D, PG&E anticipates that the resource additions identified in Tables 11 through 13 would result in PG&E meeting the applicable GHG emission targets[79] for each study year beginning with 2035 based on the CSP model published for this IRP. However, one of the challenges with demonstrating meeting those emissions targets is that the CSP model was specifically designed based on the system portfolio supporting the Conforming scenario. To demonstrate comparable GHG emission compliance for the Alternative scenarios under the same methodology, PG&E would need CSP models developed for each of its Alternative scenarios based on SERVM model simulations of each scenario's system portfolio.

Determining how to effectively and accurately model GHG emissions associated with specific LSE load requirements and generation supply resources such that the aggregation of LSE portfolio emissions reasonably represents the modeled emissions for an equivalent system is challenging. The CSP model was designed, in part, to try and achieve that outcome; however, challenges remain to enable portfolio planning flexibility for LSEs. These range from forecasted load requirements, both in total and hourly shape, to the emissions reduction effectiveness for different types and locations of supply resources due to the current CSP model's dependency on SERVM model simulation results for the specific Conforming scenario system load and resource assumptions. For future IRPs, PG&E would support the Commission pursuing the development of an updated LSE GHG emissions model that enables more LSE portfolio planning flexibility when developing their IRPs for Commission review. Utilizing a single model that can perform both capacity expansion and produce hourly production-cost modeling results, such as PLEXOS, would greatly facilitate this.

d. Local Air Pollutant Minimization and Disadvantaged Communities

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

[79] For scenarios B and C, the emissions reductions targets are the same as Scenario A. Scenario D meets PG&E's bundled share of the emissions targets for Scenario D discussed in Table 2, "Summary of Assumptions by Scenario" in Section II.b.iii.

i. Local Air Pollutants

PG&E's Conforming portfolio's local air pollutant emissions are summarized in Table 20. These emission amounts were determined using the CSP model and reflect expected reductions between 2030 and 2045 as PG&E adds incremental GHG-free energy resources to its Conforming scenario's bundled portfolio.

TABLE 20
SCENARIO A LOCAL AIR POLLUTANT EMISSIONS (TONS/YEAR)

Line No.	Description	2028	2030	2035	2040	2045
1	$PM_{2.5}$	569	530	437	301	229
2	SO_2	185	176	140	86	69
3	NOx	1,149	1,134	957	640	456

A. Focus on Disadvantaged Communities

PG&E supports the Commission's focus on DACs for this IRP, especially given the high levels of air pollutants historically recorded in DACs by the California Environmental Protection Agency (CalEPA). Many DACs are characterized by high levels of economic hardship and a relatively high energy burden compared to other communities in PG&E's service territory. Additionally, the CalEPA identifies these communities as having the highest percentile of adverse scores pertaining to poor environmental health and air quality. While the issues facing DACs extend far beyond the scope of the Commission's IRP proceeding, the IRP process is a useful venue to consider how electric sector resource planning and other related decarbonization efforts (such as clean transportation and building electrification) may impact air pollution in DACs. The IRP process also presents an opportunity for LSEs to highlight the breadth of activities and programs impacting DACs.

PG&E provides electric service to 526 census tracts that are classified as a DAC using the guiding definition for this IRP.[80] This corresponds to approximately 0.8 million residential customer

[80] For this IRP, DACs are defined as follows based on CalEPA's designation from SB 535: 1) census tracts receiving the highest 25 percent of overall scores in CalEnviroScreen 4.0; 2) census tracts lacking overall scores in CalEnviroScreen 4.0 due to data gaps, but receiving the highest 5 % of CalEnviroScreen 4.0 cumulative pollution burden scores; 3) census tracts identified in the 2017 DAC designation as disadvantaged, regardless of their scores in CalEnviroScreen 4.0; 4) lands under the control of federally recognized Tribes. OEEHHA, SB 535 Disadvantaged Communities, https://oehha.ca.gov/calenviroscreen/sb535 (as of July 17, 2026).

accounts, 0.2 million business customer accounts, and 4,200 residential customer accounts on tribal lands.[81] A full breakdown of PG&E's customers in DACs compared to the entire electric service territory is included in the Tables 21 through 23 below. Of note is the high number of DACs that are present in the Central Valley, resulting in a higher proportion of DAC residential and business customers in the Central Valley than elsewhere in the service territory.

TABLE 21
OVERALL PG&E AND DISADVANTAGED COMMUNITIES POPULATION IN PG&E ELECTRIC SERVICE TERRITORY

Line No.	Customer Types	Overall PG&E	Disadvantaged Communities	Percent of Overall PG&E
1	Residential Customers	5,010,057	850,716	17%
2	Business Customers	661,015	162,386	25%

TABLE 22
REGIONAL DISTRIBUTION OF RESIDENTIAL CUSTOMER ACCOUNTS IN PG&E ELECTRIC TERRITORY[82]

Line No.	PG&E Region	PG&E Electric Service Territory Customer Accounts (%)	PG&E Electric Service Territory Residential DAC Accounts (%)
1	Bay Area Region	1,682,533 (34%)	186,217 (22%)
2	Central Valley Region	1,083,998 (22%)	569,247 (67%)
3	North Coast Region	654,762 (13%)	25,558 (3%)
4	North Valley & Sierra Region	541,164 (11%)	29,547 (3%)
5	South Bay & Central Coast Region	1,047,600 (21%)	40,147 (5%)

Approximately 17 percent of the 5 million PG&E electric service territory residential customers live in designated DAC Census Tract Areas. Of these, over two-thirds of customers (67 percent) are in the Central Valley region, despite the Central Valley region containing only approximately one-fifth of all residential customers in PG&E's electric service territory. Residential customers residing in DACs are more likely to be people of color, as stated in the most recently released CalEnviroScreen report: "The results using the CalEnviroScreen 4.0 scores are consistent with

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

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

earlier versions of the tool, and reflect racial disparities, with the highest percentages of people of color living in the most highly impacted communities."[83]

TABLE 23
REGIONAL DISTRIBUTION OF BUSINESS ACCOUNTS IN PG&E ELECTRIC TERRITORY[84]

Line No.	PG&E Region	PG&E Business Accounts (%)	DAC Business Accounts (%)
1	Bay Area Region	160,788 (24%)	30,413 (19%)
2	Central Valley Region	188,217 (28%)	110,452 (68%)
3	North Coast Region	92,023 (14%)	4,311 (3%)
4	North Valley & Sierra Region	89,618 (14%)	6,268 (4%)
5	South Bay & Central Coast Region	130,369 (20%)	10,942 (7%)

Approximately 25 percent of PG&E's 661,015 business customers are located in DACs. These businesses are predominantly located in the Central Valley region, with approximately two thirds located in this area compared to only one fourth of all business accounts. 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.

Coupled with efforts to mitigate local air pollutants, PG&E has a broad array of programs that are designed to improve both the air quality and the economic vitality of DACs and low-income demographics in PG&E's service territory. Many of these programs have a specific program focus on DACs, including programs in PG&E's clean transportation portfolio, distributed generation programs, and building electrification programs. Further details on EV and DG programs are included in Section IV.a.viii and IV.a.vii, respectively.

PG&E conducts outreach to customers in DACs as a component of many existing programs to ensure that impacted customers and customers qualifying for program assistance are aware of the offerings. Customer outreach includes promoting income qualified programs such as the California Alternative Rates for Energy (CARE) Program to eligible customers for and communicating with customers in high wildfire threat districts with a high likelihood of being

[83] Office of Environmental Health Hazard Assessment, CalEnviroScreen 4.0 (Oct. 2021), p. 15, https://oehha.ca.gov/media/downloads/calenviroscreen/report/calenviroscreen40reportf2021.pdf (accessed July 17, 2026).

[84] 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.

impacted by a Public Safety Power Shutoff (PSPS) event. PG&E conducts much of this outreach through partnerships with Community Based Organizations (CBOs) to leverage local insights and resources to better reach customers.

PG&E Bundled Portfolio Locational Information

As of the writing of this filing, the PG&E bundled portfolio has contracts with 184 resources within five miles of an identified DAC as defined in the filing requirements. Of these 184 resources, 133 are located within a DAC. The majority of PG&E's contracted resources in, or in close proximity to, DACs are renewable or GHG-Free resources, which largely do not contribute to local criteria pollutants or CO_2 emissions within the area. PG&E contracts with 12 natural gas resources within DACs, a majority of which are Qualifying Facilities and are an average of 52 MW in nameplate capacity. Table 24 below indicates which resources contracted by PG&E are located within five miles of a DAC, and which census tract is identified as the DAC in proximity.

TABLE 24
PG&E BUNDLED PORTFOLIO DAC RESOURCE MAPPING

Line No.	Facility Name	Technology	Census Tract/Tribal Land Reservation Name
1	Conocophillips Company	Natural Gas Combustion Turbine	6013358000
2	Satellite Senior Homes	Natural Gas Combustion Turbine	6001402800
3	Hayward Area Rec & Park Dist.	Natural Gas Combustion Turbine	6001437200
4	Chevron Richmond Refinery	Natural Gas Combustion Turbine	6013377000
5	SRI International	Natural Gas Combustion Turbine	6081612000
6	Arden Wood Benevolent Assoc.	Natural Gas Combustion Turbine	6075025702
7	1080 Chestnut Corp.	Natural Gas Combustion Turbine	6075012301
8	Nihonmachi Terrace	Natural Gas Combustion Turbine	6075012301
9	Greater Vallejo Recreation District	Natural Gas Combustion Turbine	6095251200
10	City Of Milpitas	Natural Gas Combustion Turbine	6085504602
11	James B. Peter	Hydro: Small	Greenville Rancheria
12	Yuba City Racquet Club	Natural Gas Combustion Turbine	6101050302
13	Lofton Ranch	Hydro: Small	Big Bend Rancheria
14	Swiss America	Hydro: Small	Auburn Rancheria
15	Monterey Regional Water	Biogas Generation	6053014102
16	Chevron USA (taft/cadet)	Natural Gas Combustion Turbine	6029003303
17	Chevron USA (Cymric)	Natural Gas Combustion Turbine	6029003304
18	Aera Energy LLC. (S. Belridge)	Natural Gas Combustion Turbine	6029004500
19	Chevron USA (coalinga)	Natural Gas Combustion Turbine	6019007902

TABLE 24
PG&E BUNDLED PORTFOLIO DAC RESOURCE MAPPING
(CONTINUED)

Line No.	Facility Name	Technology	Census Tract/Tribal Land Reservation Name
20	Berry Petroleum Company – Tannehill Facility	Natural Gas Combustion Turbine	6029003303
21	Chevron USA (Se Kern River)	Natural Gas Combustion Turbine	6029005103
22	Chevron Usa (Eastridge)	Natural Gas Combustion Turbine	6029005103
23	Aera Energy LLC. (Coalinga)	Natural Gas Combustion Turbine	6019007902
24	Sentinel Peak Resources (Dome)	Natural Gas Combustion Turbine	6029003304
25	Panoche Energy Center (aka Cinergy & EIF - Firebaugh)	Natural Gas Combustion Turbine	6019008302
26	Montezuma Wind Energy Center	Wind	6095253500
27	CalRenew 1	Solar Photovoltaic	6019008301
28	Shiloh II Wind	Wind	6095253500
29	High Plains Ranch II LLC (HPR2), part of California Valley Solar Ranch	Solar Photovoltaic	6029003304
30	Ivanpah Unit 1	Solar Thermal	6071010300
31	Ivanpah Unit 3	Solar Thermal	6071010300
32	High Plains Ranch III LLC (HPR3), part of California Valley Solar Ranch (CVSR)	Solar Photovoltaic	6029003304
34	DTE Stockton	Biomass	6077000801
35	Alpaugh Solar Project	Solar Photovoltaic	6107004300
36	Alpaugh North	Solar Photovoltaic	6107004300
37	Atwell Island	Solar Photovoltaic	6107004300
38	Corcoran	Solar Photovoltaic	6019006202
39	White River	Solar Photovoltaic	6107004300
40	Avenal Park	Solar Photovoltaic	6031001701
41	Sun City	Solar Photovoltaic	6031001701
42	Sand Drag	Solar Photovoltaic	6031001701
43	Sunshine Landfill	Biogas Generation	6037106510
44	Potrero Hills Landfill	Biogas Generation	6095253500
45	Coram Brodie	Wind	6029006500
46	Shiloh III Wind Project	Wind	6095253500
47	North Star Solar I	Solar Photovoltaic	6019008302
48	Montezuma II	Wind	6095253500
49	La Joya Del Sol #1	Solar Photovoltaic	6019001800
50	Kansas South	Solar Photovoltaic	6031001601
51	Westlands Solar Farms PV1	Solar Photovoltaic	6019007801
52	FRV Orion Solar I	Solar Photovoltaic	6029006202
53	Nickel 1	Solar Photovoltaic	6029004500

TABLE 24
PG&E BUNDLED PORTFOLIO DAC RESOURCE MAPPING
(CONTINUED)

Line No.	Facility Name	Technology	Census Tract/Tribal Land Reservation Name
54	Shiloh IV Wind Project	Wind	6095253500
55	2081_Terzian	Solar Photovoltaic	6019006300
56	2097_Helton	Solar Photovoltaic	6047002500
57	2102_Christensen	Solar Photovoltaic	6019006900
58	2096_Cotton	Solar Photovoltaic	Berry Creek Rancheria
59	2179-Smotherman	Solar Photovoltaic	Enterprise Rancheria
60	Oakley Executive RV and Boat Storage AKA Oakley Executive – Solar	Solar Photovoltaic	6013302005
61	Kingsburg 1	Solar Photovoltaic	6107000301
62	Kingsburg 2	Solar Photovoltaic	6107000301
63	Kingsburg 3	Solar Photovoltaic	6107000301
64	RE Kansas LLC	Solar Photovoltaic	6031001601
65	Lost Hills Solar	Solar Photovoltaic	6029004500
66	Blackwell Solar	Solar Photovoltaic	6029004500
67	Henrietta Solar PV	Solar Photovoltaic	6031001601
68	RE Kent South LLC	Solar Photovoltaic	6031001601
69	SKIC Solar 1 (South Kern Solar PV Plant)	Solar Photovoltaic	6029003304
70	White River West 19.75 MW Solar Facility	Solar Photovoltaic	6107004300
71	Columbia Solar Energy, LLC	Solar Photovoltaic	6013309000
72	Alamo Solar	Solar Photovoltaic	6071011700
73	Corcoran Solar LLC	Solar Photovoltaic	6031001300
74	Merced Solar Project	Solar Photovoltaic	6047000901
75	Bidart Dairy III (Old River)	Biogas Generation	6029003304
76	Mission Solar Project	Solar Photovoltaic	6047000901
77	RE Old River One LLC	Solar Photovoltaic	6029003206
78	Shafter Solar Farm	Solar Photovoltaic	6029003900
79	Morelos Solar, LLC (Morelos Del Sol)	Solar Photovoltaic	6029004500
80	APEX 646-460	Solar Photovoltaic	6107000202
81	Fresno Solar South	Solar Photovoltaic	6019003900
82	Fresno Solar West	Solar Photovoltaic	6019003900
83	Sirius Solar Project	Solar Photovoltaic	6047001901
84	Lincoln Metering and Hydroelectric Station	Hydro: Small	Auburn Rancheria
85	Castor Solar Project	Solar Photovoltaic	6029003304
86	Peacock Solar Project	Solar Photovoltaic	6107000202
87	Lemoore 1	Solar Photovoltaic	6031001601

TABLE 24
PG&E BUNDLED PORTFOLIO DAC RESOURCE MAPPING
(CONTINUED)

Line No.	Facility Name	Technology	Census Tract/Tribal Land Reservation Name
88	Bakersfield III	Solar Photovoltaic	6029003103
89	2154 Foote	Solar Photovoltaic	6007003700
90	2192 Ramirez	Solar Photovoltaic	Paskenta Rancheria
91	Rising Tree Wind Farm LLC	Wind	6029006500
92	Woodmere Solar Farm	Solar Photovoltaic	6029006202
93	Diablo Winds	Wind	6077005206
94	NDP1	Solar Photovoltaic	6047002401
95	Midway I Solar Farm - 83WI 8ME, LLC	Solar Photovoltaic	6025010102
96	California Flats Solar Farm, LLC	Solar Photovoltaic	6019007902
97	Site 980	Hydro: Small	6039000507
98	Site 1174	Hydro: Small	6039000507
99	Site 1923	Hydro: Small	6039000201
100	Site 1302	Hydro: Small	6039000507
101	SR Solis Oro Loma Teresina, LLC-Project A	Solar Photovoltaic	6019008402
102	Sunray 2	Solar Photovoltaic	6071010300
103	Avenal Solar - Project A	Solar Photovoltaic	6031001701
104	SR Solis Oro Loma Teresina, LLC-Project B	Solar Photovoltaic	6019008402
105	CED Avenal, LLC - Project B	Solar Photovoltaic	6031001701
106	CED Corcoran Solar 3, LLC	Solar Photovoltaic	6031001200
107	Westside Solar, LLC	Solar Photovoltaic	6019007802
108	Aspiration Solar G LLC	Solar Photovoltaic	6019008200
109	Goose Valley Hydro	Hydro: Small	Pit River Trust Land
110	Bakersfield 1	Solar Photovoltaic	6029002400
111	Winter Wheat (FKA GASNA 36P, LLC (San Joaquin 1B))	Solar Photovoltaic	6019008200
112	Summer Wheat (FKA GASNA 6P, LLC (San Joaquin 1A))	Solar Photovoltaic	6019008200
113	Bakersfield Industrial 1	Solar Photovoltaic	6029002500
114	Delano Land 1	Solar Photovoltaic	6029004500
115	Manteca Land 1	Solar Photovoltaic	6077005131
116	Merced 1	Solar Photovoltaic	6047002100
117	Tranquillity 8 Amarillo	Solar Photovoltaic	6019008302
118	Java Solar Project	Solar Photovoltaic	6031001601
119	Redwood 4 Solar Farm	Solar Photovoltaic	6029006202
120	Madera 1	Solar Photovoltaic	6039000201

TABLE 24
PG&E BUNDLED PORTFOLIO DAC RESOURCE MAPPING
(CONTINUED)

Line No.	Facility Name	Technology	Census Tract/Tribal Land Reservation Name
121	Grasshopper Flats (FKA Nelson Creek)	Hydro: Small	Big Bend Rancheria
122	Silver Springs Facility	Hydro: Small	Roaring Creek Rancheria
123	Eagle Solar	Solar Photovoltaic	6029003304
124	ABEC #2 LLC dba West-Star North Dairy Biogas	Biogas Generation	6029004200
125	ABEC #3 LLC dba Lakeview Dairy Biogas	Biogas Generation	6029003304
126	ABEC #4 LLC dba CE&S Dairy Biogas	Biogas Generation	6029003304
127	North Fork Community Power	Biomass	North Fork Rancheria
128	Verwey-Hanford Dairy Digester Genset #2	Biogas Generation	6031001200
129	Verwey-Hanford Dairy Digester III	Biogas Generation	6031001200
130	Verwey Madera Dairy Digester Genset #2	Biogas Generation	6039000400
131	Diamond H Dairy Power	Biogas Generation	6039000202
132	Burney Forest Products	Biomass	Pit River Trust Land
133	Highway 43	Solar Photovoltaic	6029004000
134	Kern Sunset	Solar Photovoltaic	6029006201
135	Fresno Disadvantaged Community Solar Project	Solar Photovoltaic	6019001900
136	Tulare CSG	Solar Photovoltaic	6107004200
137	Nachtigall	Solar Photovoltaic	6029004301
138	Pistachio Road	Solar Photovoltaic	6029004500
139	Terry	Solar Photovoltaic	6029004301
140	Fishwater Release Hydro	Hydro: Small	6039001000
141	Jaton LLC	Solar Photovoltaic	6029004500
142	East Cleveland Road Solar	Solar Photovoltaic	6047000901
143	Kings CSG 3 LLC	Solar Photovoltaic	6031001601
144	Althea Avenue Solar Phase I	Solar Photovoltaic	6019008402
145	Avenue 26 Solar (Phase 2)	Solar Photovoltaic	6039000201
146	Avenue 26 Solar (Phase 1)	Solar Photovoltaic	6039000201
147	Burney Forest Products	Biomass	Pit River Trust Land
148	Rio Vista RV and Boat Storage	Solar Photovoltaic	6095253500
149	Pittsburg RV and Boat Storage	Solar Photovoltaic	6013305000
150	RuAnn Dairy Digester	Biogas Generation	6019007700
151	Tesoro Commons LLC	Solar Photovoltaic	6077005114
152	Northern Orchard Solar	Solar Photovoltaic	6029003304
153	Godinho Dairy Digester	Biogas Generation	6047002000

TABLE 24
PG&E BUNDLED PORTFOLIO DAC RESOURCE MAPPING
(CONTINUED)

Line No.	Facility Name	Technology	Census Tract/Tribal Land Reservation Name
154	David teVelde Dairy Digester (BioM)	Biogas Generation	6031000100
155	American Canyon RV Boat Storage	Solar Photovoltaic	6095251902
156	Althea Avenue Solar Phase II	Solar Photovoltaic	6019008402
157	Stockton 1	Solar Photovoltaic	6077003700
158	Stockton 9	Solar Photovoltaic	6077003803
159	Flying Goose Deuce	Solar Photovoltaic	6029004500
160	VERO Geothermal	Geothermal	6025010102
161	Sierra Energy Storage	Lithium Ion	Chicken Ranch Rancheria
162	Cascade Energy Storage	Lithium Ion	6077002800
163	Diablo Energy Storage	Lithium Ion	6013310000
164	Unit 1 - Moss 300	Lithium Ion	6053010101
165	Diablo Energy Storage	Lithium Ion	6013310000
166	Diablo Energy Storage	Lithium Ion	6013310000
167	Diablo Energy Storage	Lithium Ion	6013310000
168	Moss 100	Lithium Ion	6053010101
169	Daggett 2	Lithium Ion	6071010300
170	Daggett 3	Lithium Ion	6071010300
171	LeConte	Lithium Ion	6025011900
172	Moss Landing Energy Storage 3	Lithium Ion	6053010101
173	Poblano Energy Storage	Lithium Ion	San Manuel Reservation
174	Caballero CA Storage, LLC	Lithium Ion	6083002502
175	Kola Energy Storage, LLC	Lithium Ion	6077005206
176	Beaumont ESS 1, LLC	Lithium Ion	6065044000
177	Sanborn ESS III, LLC	Lithium Ion	6029005900
178	Bear Canyon Storage Project	Lithium Ion	Middletown Rancheria
179	Northern Orchard Battery Storage	Lithium Ion	6029003304
180	Gabriel Project	Lithium Ion	6037404600
181	Marici Project	Lithium Ion	6037408202
182	Dirac Project	Lithium Ion	6071000606

PG&E has proposed the addition of resources to its portfolio to meet both reliability and emissions targets across the forecast horizon in this IRP, and these resources may be located within or in proximity to DACs. However, PG&E plans to procure GHG-Free and renewable resources and is not proposing additional natural gas or other fossil fuel powered resources, and therefore does not expect new resources to negatively impact the DACs in which they may

be located. Additionally, the Commission's assumptions underlying this plan show natural gas combined heat and power (CHP) facilities being phased out between 2036 and 2040[85] which could potentially further reduce emissions in disadvantaged communities. PG&E does not provide granular locational information for its modeled resources additions as actual locations depend on actual resource development. However, when soliciting offers for new resources, PG&E makes it clear to developers that location will be considered, and preference may be given to projects located in DACs when compared to projects with similar quantitative rankings not located in DACs. DAC status may have been used as a differentiating factor in procurement evaluations and portfolio selection decisions when comparing otherwise similarly ranked offers in past procurement efforts.

e. Cost and Rate Analysis

As required, the revenue requirements and corresponding rate analysis have been separated between the baseline portfolio (Table 26) and Conforming Scenario (Table 27) where the only difference between the two portfolios is the net cost[86] forecast of the planned resource additions for the Conforming Scenario. PG&E notes that while the baseline results exclude the direct net cost impacts from the planned resource additions identified for PG&E's bundled generation portfolio, the forecasted impacts on wholesale energy, RA, and clean commodity prices from planned resource additions across all load serving entities are still reflected. The revenue requirement and rate tables are also expressed in real 2024 dollars, consistent with the presentation described in the filing requirements.

As ordered, the rate presentation includes both the Simple Average Delivery Rate (SADR) containing the rate components recovered from all PG&E customers, and the Simple Average Bundled Rate (SABR), which includes the bundled generation rate from PG&E's portfolio plus the SADR to determine the average system rate for bundled customers.

As described in Section II of this report, the Conforming Scenario relied on the Commission's planning assumptions for natural gas prices and GHG allowance costs from the RESOLVE inputs

[85] 2026 IRP Inputs & Assumptions, p.17 and p.26: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf (accessed August 3, 2026)

[86] Net cost equals the difference between the forecasted resource costs less their forecasted market value.

shown in Table 25 below to develop price assumptions used for bundled energy market purchases and revenues for generation market sales.

TABLE 25
PG&E CITYGATE NATURAL GAS AND GHG ALLOWANCE PRICES
(2024 $)

Line No.	Year	PG&E Citygate Natural Gas Price	GHG Allowance Price
1	2024	$5.59	$24.45
2	2025	$5.60	$25.79
3	2026	$5.60	$27.10
4	2027	$5.59	$28.50
5	2028	$5.58	$29.95
6	2029	$5.58	$31.49
7	2030	$5.58	$33.14
8	2031	$5.57	$34.87
9	2032	$5.57	$36.70
10	2033	$5.56	$38.61
11	2034	$5.55	$40.62
12	2035	$5.55	$42.73
13	2036	$5.54	$44.95
14	2037	$5.54	$47.49
15	2038	$5.53	$49.78
16	2039	$5.53	$52.39
17	2040	$5.53	$55.14
18	2041	$5.52	$58.08
19	2042	$5.52	$61.19
20	2043	$5.51	$64.47
21	2044	$5.51	$67.90
22	2045	$5.51	$71.53

For reference, the natural gas price assumptions used in RESOLVE show a significant variance compared to actual prices observed between 2024 and the first half of 2026. For example, the average PG&E Citygate natural gas price forecast provided by the Commission for 2025 and 2026 is $5.60/MMBtu while actual PG&E Citygate gas prices averaged $3.28/MMBtu for 2025

and $1.71/MMBtu for January through June 2026.[87] Natural gas prices are a key modeling assumption, and actual prices in the future will impact procurement decisions and costs that could deviate significantly from this forecast.

In addition to the natural gas and GHG allowance cost assumptions used in RESOLVE, PG&E's generation revenue requirement forecast also reflects RA and REC price assumptions based on the price forecast methodologies for each described in Section II.b.ii. As required for the Conforming Scenario, PG&E based the cost for contracting with existing and new resources on the levelized cost of energy (LCOE) inputs used in RESOLVE for the IRP for each identified technology type. However, as described in Section II.b.ii, PG&E believes that the LCOE inputs used for the IRP understate expected new resource costs and that the cost assumptions used in RESOLVE for developing the TPP portfolios are more representative of costs to be incurred.

For the other components of its revenue requirement forecast (transmission, distribution, DSM programs, and other), PG&E created a forecast that incorporates all approved revenue requirements and pending revenue requirement requests. PG&E notes that the rate forecasts provided in the IRP are indicative and reflect the expected impacts from the assumptions required by the Commission for modeling the Conforming Scenario. Actual realized rates will depend upon future realized market prices, the outcomes of future rate cases (in particular GRCs), other ongoing proceedings, and market conditions. Future rate forecasts will reflect the information available at that time and may lead to updated revenue requirements associated with additional (or reduced) future costs including, but not limited to, T&D upgrades, grid modernization costs, clean transportation infrastructure costs, and changes based on PG&E's cost of capital.

[87] Nominal prices converted to 2024 dollars.

TABLE 26
REVENUE REQUIREMENTS AND BUNDLED SYSTEM AVERAGE RATES FOR BASELINE SCENARIO
(2024 $MILLIONS)

Line No.	Cost Category	2027	2028	2029	2030	2031	2032	2033	2034	2035	2040	2045
1	Distribution	$ 10,190	$ 9,937	$ 10,282	$ 10,810	$ 10,986	$ 11,193	$ 11,398	$ 11,607	$ 11,821	$ 12,933	$ 14,124
2	Transmission	$ 3,077	$ 3,682	$ 4,176	$ 4,665	$ 5,145	$ 5,559	$ 5,416	$ 5,248	$ 5,335	$ 5,850	$ 6,419
3	Generation	$ 3,101	$ 3,238	$ 3,486	$ 3,895	$ 4,297	$ 4,746	$ 4,907	$ 4,984	$ 5,008	$ 5,108	$ 5,142
4	Demand Side Programs	$ 466	$ 526	$ 529	$ 551	$ 532	$ 524	$ 509	$ 499	$ 490	$ 443	$ 399
5	Other	$ 582	$ 730	$ 718	$ 706	$ 694	$ 681	$ 668	$ 655	$ 642	$ 581	$ 523
6 (sum lines 1-5)	Baseline Revenue Requirement	$ 17,415	$ 18,113	$ 19,191	$ 20,627	$ 21,654	$ 22,703	$ 22,899	$ 22,993	$ 23,296	$ 24,913	$ 26,607
7	System Sales (GWh)	82,139	90,770	97,841	104,793	111,031	115,345	120,684	125,467	130,179	145,985	155,228
8	Bundled Sales (GWh)	26,740	28,579	32,543	36,271	39,184	40,857	43,618	45,624	47,268	53,014	56,391
9	System Average Delivery Rate (¢/kWh)	17.43	16.39	16.05	15.97	15.63	15.57	14.91	14.35	14.05	13.57	13.83
10	Bundled Generation Rate (¢/kWh)	11.60	11.33	10.71	10.74	10.97	11.62	11.25	10.92	10.59	9.63	9.12
11	Bundled System Average Rate (¢/kWh)	29.02	27.72	26.76	26.70	26.60	27.18	26.16	25.28	24.64	23.20	22.95

(a) Totals may not add due to rounding.

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

(c) Note that Line 2 represents generation costs for only PG&E Bundled customers while Lines 1, 2, 4, and 5 represent costs for all PG&E System customers. In Line 6, PG&E sums the values for Lines 1 through 5 as required although they have different representations.

TABLE 27
REVENUE REQUIREMENTS AND BUNDLED SYSTEM AVERAGE RATES FOR SCENARIO A
(2024 $MILLIONS)

Line No.	Cost Category	2027	2028	2029	2030	2031	2032	2033	2034	2035	2040	2045
1	Distribution	$ 10,190	$ 9,937	$ 10,282	$ 10,810	$ 10,986	$ 11,193	$ 11,398	$ 11,607	$ 11,821	$ 12,933	$ 14,124
2	Transmission	$ 3,077	$ 3,682	$ 4,176	$ 4,665	$ 5,145	$ 5,559	$ 5,416	$ 5,248	$ 5,335	$ 5,850	$ 6,419
3	Generation	$ 3,101	$ 3,238	$ 3,486	$ 4,055	$ 4,464	$ 4,942	$ 5,102	$ 5,193	$ 5,221	$ 5,117	$ 5,194
4	Demand Side Programs	$ 466	$ 526	$ 529	$ 551	$ 532	$ 524	$ 509	$ 499	$ 490	$ 443	$ 399
5	Other	$ 582	$ 730	$ 718	$ 706	$ 694	$ 681	$ 668	$ 655	$ 642	$ 581	$ 523
6 (sum lines 1-5)	Baseline Revenue Requirement	$ 17,415	$ 18,113	$ 19,191	$ 20,788	$ 21,821	$ 22,899	$ 23,094	$ 23,202	$ 23,509	$ 24,922	$ 26,659
7	System Sales (GWh)	82,139	90,770	97,841	104,793	111,031	115,345	120,684	125,467	130,179	145,985	155,228
8	Bundled Sales (GWh)	26,740	28,579	32,543	36,271	39,184	40,857	43,618	45,624	47,268	53,014	56,391
9	System Average Delivery Rate (¢/kWh)	17.43	16.39	16.05	15.97	15.63	15.57	14.91	14.35	14.05	13.57	13.83
10	Bundled Generation Rate (¢/kWh)	11.60	11.33	10.71	11.18	11.39	12.10	11.70	11.38	11.05	9.65	9.21
11	Bundled System Average Rate (¢/kWh)	29.02	27.72	26.76	27.15	27.03	27.66	26.61	25.73	25.09	23.22	23.04

(a) Totals may not add due to rounding.

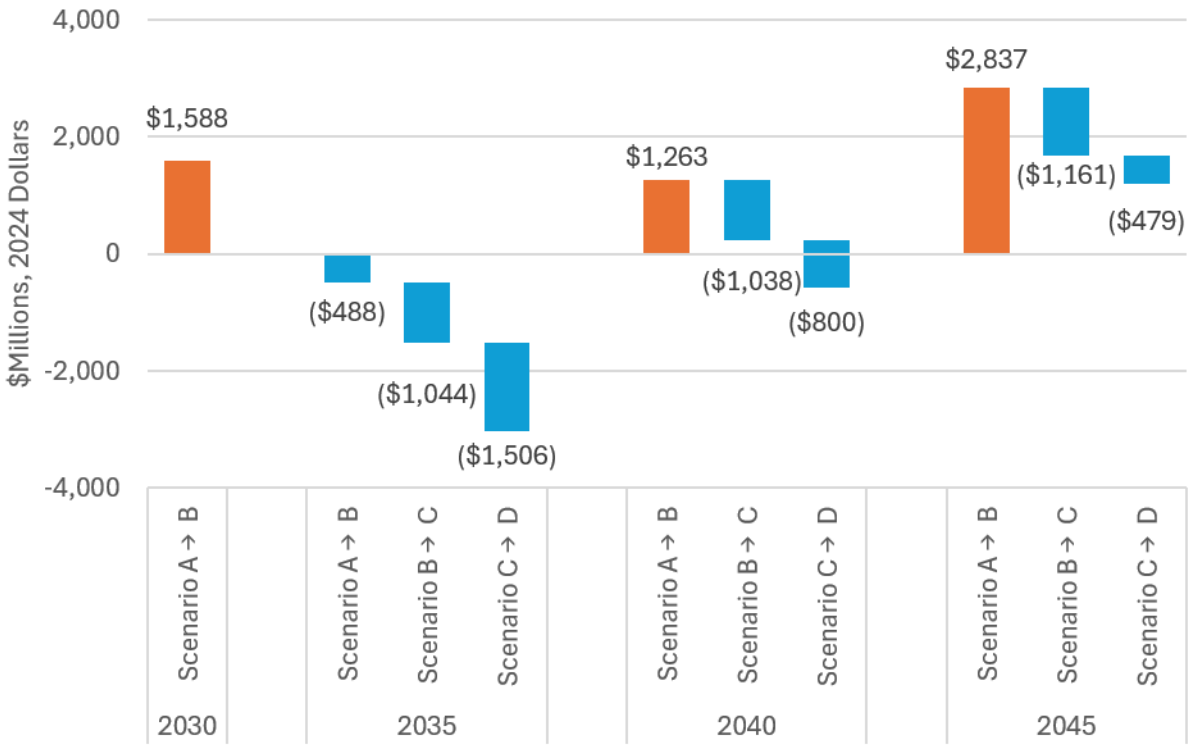
(b) See Revenue Requirement and Rates Modeling in the Methodology section for SADR and SABR calculation methodology.

(c) Note that Line 2 represents generation costs for only PG&E Bundled customers while Lines 1, 2, 4, and 5 represent costs for all PG&E System customers. In Line 6, PG&E sums the values for Lines 1 through 5 as required although they have different representations.

i. Alternative Scenario Optimized System Cost Results

Unlike the physical position results presented throughout most of this Study Results section for the Conforming and Alternative scenarios, it is more challenging to produce comparable bundled customer rate results given the different market and policy dynamics impacting short-term commodity price forecasts and their corresponding rate impacts as well as differences in transmission system investments given the significant differences in new resource development between scenarios. As a result, PG&E utilized the system-wide modeling results generated by RESOLVE to compare the customer affordability benefits between each of the modeled scenarios, which are presented in Figure 7 below.

FIGURE 7
SCENARIO IMPACT ON RESOLVE OPTIMIZED SYSTEM COST (LOWER IS BETTER), 2024 DOLLARS



As described in Sections II.b.iii and III.n, PG&E's alternative Scenario B better reflects both the quantity and technology mix of resources forecasted to be developed through 2030 as well as the differences in new resource technology cost assumptions, using the technology costs utilized by the Commission in developing its 26-27 TPP portfolio. Based on the more realistic and feasible assumptions utilized by PG&E for Scenario B, RESOLVE total optimized system

costs are estimated to be $1,588 million higher in 2030 and $1,204 million per year higher from 2035 through 2045[88] driven by the higher technology cost assumptions.

With Scenario B established as the comparison baseline, Scenario C's extension of DCPP through 2045 shows average annual savings of $1,081 million per year between 2035 and 2045. Due to the constrained resource build assumptions, DCPP's operation is not offsetting any new resource build costs, so savings are negligible through 2030, but there are GHG-emission-reduction impacts of over 6 MMT/yr. These savings estimates are consistent with the Commission's published results for a DCPP Extension scenario as part of its 26-27 TPP analysis.[89] In the Commission's analysis, a further extension of DCPP could save customers between approximately $1 billion and $2 billion per year driven by lower transmission upgrade costs and avoided costs of higher priced new renewable and energy storage resources that would be needed to replace DCPP. The Massachusetts Institute of Technology's (MIT) Center for Energy and Environmental Policy Resource published commentary on the CPUC's 26-27 TPP analysis,[90] affirming the Commission's conclusions and the 2021 Stanford / MIT study that further extending DCPP would result in lower customer costs and accelerate decarbonizing the electric grid.

Focusing further on customer affordability, Scenario D projects customer revenue requirements to decrease an additional approximately $928 million per year compared to Scenario C as a result of more balanced new resource and transmission development for achieving California's 2045 GHG emissions goals.

ii. Gap in Transmission and Distribution Cost Assumptions

Over the coming decades California will need to invest billions of dollars to build new transmission and distribution to bring on the resource capacity necessary to meet growing customer electric demands and achieve the SB 100 target of 100 percent clean energy sales by 2045. These required upgrades will not only encompass the high-voltage transmission lines needed to access new in-state and OOS resources, but also must be made at the distribution

[88] Calculated as average of 2035, 2040, and 2045 values since RESOLVE does not produce outputs for every year in the study horizon.

[89] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2026-2027-tpp/ruling_26-27-tpp-results_updated_20251013.pdf (accessed August 3, 2026)

[90] https://ceepr.mit.edu/wp-content/uploads/2026/04/MIT-CEEPR-RC-2026-03.pdf.

level to accommodate the growing load from residential electrification and EV penetration. In the most recent publication of CAISO's 20-Year Transmission Outlook,[91] the study suggests that to bring on 165.1 GW necessary to serve CAISO's 2045 load demand, the transmission development cost is estimated to be between $45.8 and $63.2 Billion. While this study largely focuses on transmission, additional costs required to upgrade substations and distribution circuits will need to be considered. One estimate of such costs comes from part 2 of PG&E's Electrification Impact Study[92] which estimates in PG&E territory alone, "electrification requires between $23 billion and $31 billion of distribution electrification investments through 2040."[93] Further analysis and future studies will be required to better understand the total transmission and distribution infrastructure investments more accurately at the CAISO level.

f. System Reliability Analysis

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

As required by the 2026 IRP filing requirements for LSEs, Table 28 and Figure 8 demonstrate PG&E meeting the reliability requirements for its Conforming Scenario.[94]

[91] https://www.caiso.com/documents/2024-20-year-transmission-outlook-jul-31-2024.pdf (accessed August 3, 2026).

[92] Fowlie, Meredith, What Will Electrification Cost (the Distribution System)? (June 27, 2022), Energy Institute Blog, UC Berkeley, https://energyathaas.wordpress.com/2022/06/27/what-will-electrification-cost-the-distribution-system/ (accessed August 3, 2026)

[93] EIS, page 14. https://www.ethree.com/wp-content/uploads/2026/02/PGE_EIS.pdf (accessed August 3, 2026)

[94] PG&E did not complete full RDTs for Scenarios B, C, and D, but expect each portfolio satisfies the RDT reliability requirements given they satisfy the SoD System RA requirements.

TABLE 28
CONFORMING SCENARIO RELIABILITY (MW)
CONFIDENTIAL

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
LSE reliability need (MW)	[redacted]																			
ELCC by contract status (effective MW)																				
Online																				
Development																				
Review																				
PlannedExisting																				
PlannedNew																				
BTM PV																				
LSE total supply (effective MW)																				
Net capacity position (+ve = excess, -ve = shortfall) (effective MW)	1,353	907	795	1,252	1,720	1,830	1,420	1,098	862	394	598	709	794	891	908	832	838	607	731	651

FIGURE 8
SCENARIO A RELIABILITY (MW)
CONFIDENTIAL



In addition to the system reliability assessment included in the RDT, PG&E completed an assessment of all four scenarios for meeting the forecasted PG&E bundled SoD System RA requirements. The optimized SoD peak hour results for September in each scenario are shown in Figures 9 through 12 below, while the portfolios for each scenario satisfy the hourly SoD requirements across all months and years of the study horizon.

FIGURE 9
SCENARIO A SLICE-OF DAY RELIABILITY POSITION

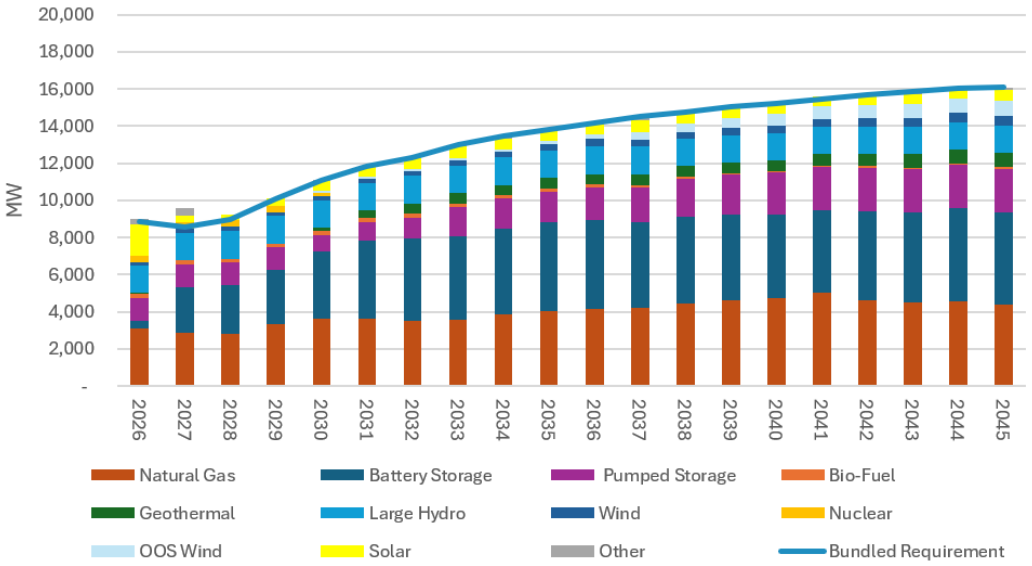


FIGURE 10
SCENARIO B SLICE-OF-DAY RELIABILITY POSITION

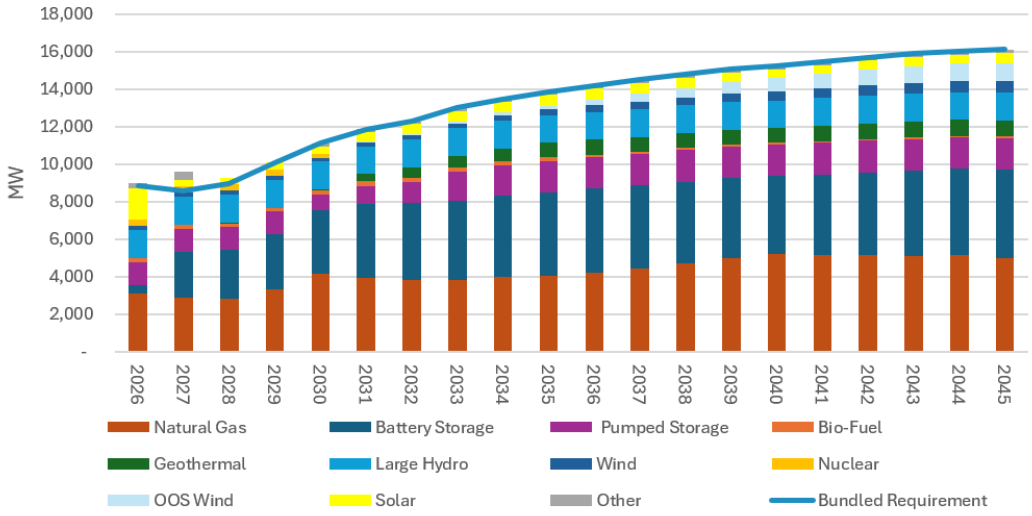


FIGURE 11
SCENARIO C SLICE-OF-DAY RELIABILITY POSITION

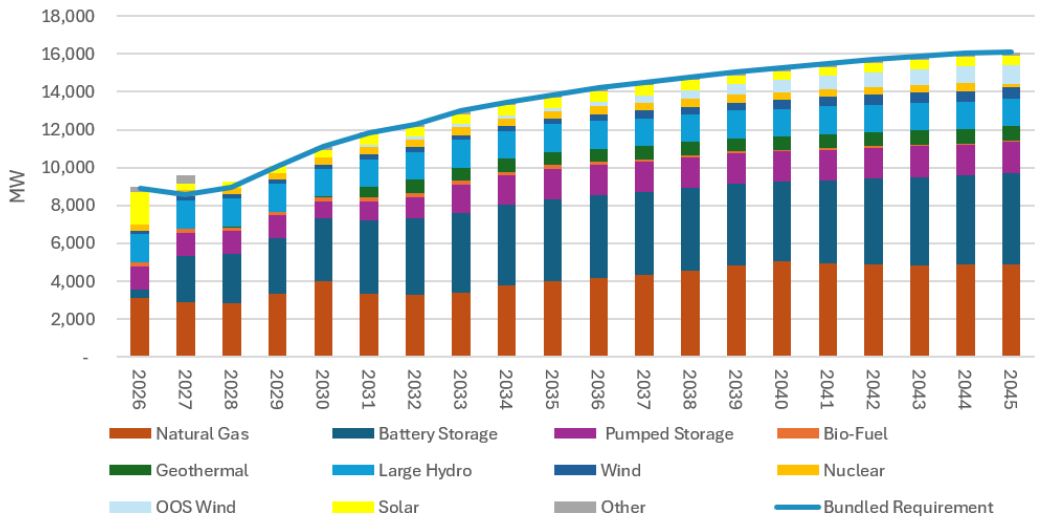
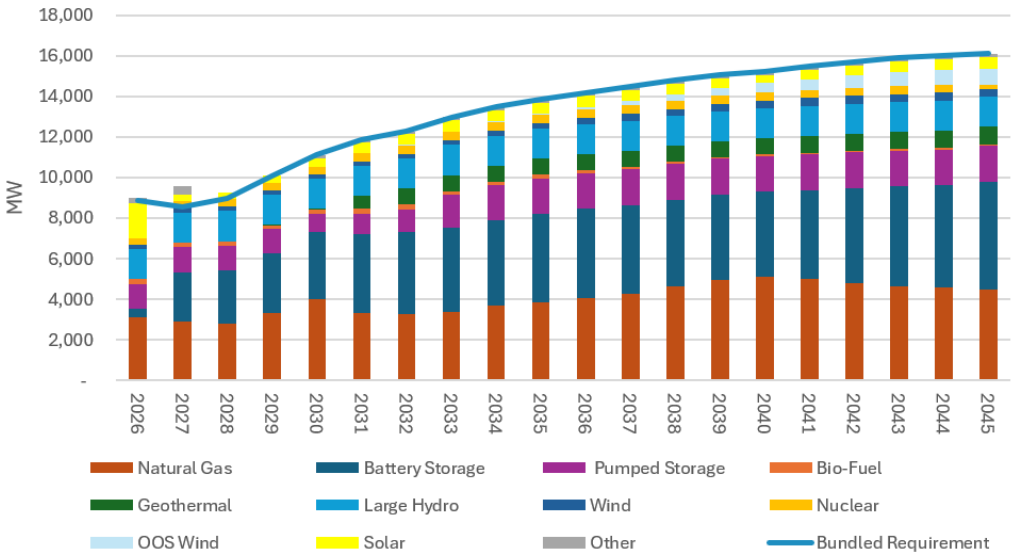


FIGURE 12
SCENARIO D SLICE-OF-DAY RELIABILITY POSITION



g. Existing Resource Planning

For its 2026 IRP portfolios PG&E took a similar approach as it did in its previous 2018, 2020, and 2022 IRP plans regarding existing resources. As described in Section III.a, a majority of PG&E's baseline portfolio is comprised of existing resources that are already online and delivering to PG&E's customers, contracted resources that are under development, and planned new resources that PG&E is actively pursuing in response to mandated procurement programs and procurement orders such as the 2026 IRP procurement decision earlier this year. Given the 2026 IRP planning horizon is through 2045, a majority of PG&E's contracted portfolio will have expired beforehand. As a result, PG&E developed a methodology for incorporating existing resources expected to be available to the market into its process for determining future planned resource additions. This methodology separated resources based on whether they were located in local transmission capacity planning areas.

As described in Section III.a.ii, given the limited consideration of local reliability planning in the IRP currently, PG&E's planned portfolio additions include an assumption regarding future contracts with natural gas-fired generators to ensure local reliability requirements are being met in PG&E's service territory. Specifically, PG&E assumes that all of the non-utility owned natural gas-fired generators located within PG&E local capacity areas will sign contracts with the CPE up to the additions needed to meet the forecasted local transmission area capacity requirements, and have their reliability attributes proportionally allocated to LSEs within PG&E's service area.[95] PG&E based the local transmission area capacity requirements for its service territory on the 2030 local capacity requirements need of approximately 14,700 MW published in the 2026 Local Capacity Technical Study Final Report,[96] less capacity expected to be available towards meeting the local capacity requirements without being contracted by the CPE (e.g. renewables). This assumption is consistent with the CPUC's system portfolio, which assumes these resources are available to the CAISO through the IRP's 2045 planning horizon.

For existing non-local resources and remaining existing local capacity in excess of the local area capacity requirements, PG&E developed one approach for GHG-free resources and another for natural gas-fired generators. For GHG-free resources, PG&E compiled a comprehensive dataset of existing GHG-free energy contracts based on publicly available data for IOU and non-IOU

[95] Consistent with the 2026 IRP filing requirements, PG&E is only including its bundled load share of assumed future CPE procurement in its RDT.

[96] 2026 Local Capacity Technical Study, https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-2026-Local-Capacity-Technical-Report.pdf (accessed August 3, 2026).

LSEs. Table 29 below summarizes the contract capacity by contract expiration year and technology type.

TABLE 29
CUMULATIVE GROSS AVAILABLE CAPACITY FROM EXPIRING RESOURCES (MW)

Line No.	Technology	2030	2035	2040	2045
1	Solar PV	54	5,350	14,225	18,225
2	Wind	361	3,774	6,281	6,316
3	Biomass	0	94	139	139
4	Geothermal	31	91	91	522
5	Small Hydro	0	46	46	46
6	4-hr Battery	0	634	3,776	9,233

As part of PG&E's planned resource addition process, PG&E first considered available capacity from expiring GHG-free resource contracts up to a maximum capacity based on PG&E's share of the CPUC-jurisdictional load forecast. As shown in Tables 10 through 14, PG&E's planned additions fully utilize the bundled share of existing resources across all four scenarios.

For existing natural-gas fired generator capacity supply that remained after considering the local transmission requirement needs, PG&E set a maximum short-term baseload RA purchase limit equal to the bundled share of such capacity. The quantity assumed for September across the planning horizon is reflected in the reliability data presented as part of the System Reliability Analysis.

The issue of future contract assumptions for existing resources, in particular GHG-free resources, is critical for ensuring that the needed amount of 'planned new' resources is developed over time and developed equitably across all LSEs. Given the difficulties that individual LSEs face regarding identifying an existing resource for future procurement that is not also being identified by another LSE, the CPUC should consider adopting PG&E's approach to proportionally allocating the energy and reliability attributes of existing generators for all years after their existing contracts expire through their planned retirement date as part of their standard IRP planning assumptions.[97] This would ensure a more equitable representation of planned new procurement across LSEs within their IRPs while actual future LSE procurement will likely be a combination of agreements with both new and existing generators.

[97] Similar to the IFM CHP resource allocation methodology currently implemented in the CSP model.

The addition of PG&E's pro rata share of statewide expected expiring resources is new to this 2026 IRP and was not included in PG&E's 2022 LSE IRP. As PG&E's modeling shows resources are needed in excess of PG&E's share of expiring existing resources, the entirety of PG&E's pro rata share of existing resources are included in each portfolio, resulting in a cumulative 5.8 GW of existing resources. In the 2022 IRP, PG&E did not assume any planned GHG-free resource additions were with existing generators since the planning horizon only went through 2035.

h. Hydro Generation Risk Management

As presented in Tables 5 and 6, PG&E's bundled customers rely on a variety of generation technology types for providing carbon-free energy and system capacity. While the proportional contribution differs between energy and capacity, hydroelectric resources play a critical role in PG&E meeting both its reliability and GHG emission planning requirements.

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

i. Risk of in-state drought

A. Hydro Generation for 2026 IRP

For the 2026 IRP, PG&E modified 15-year historical average hydroelectric generation conditions to account for the future impacts of climate change and FERC relicensing. The hydroelectric generation assumption is used in the forecasts of energy production, GHG emissions and expected costs.

1) This 15-year average reflects potential near-term climate change impacts, including years with warmer temperatures, decreased snowpack, and flood affects, as well as the recent extreme droughts and other watershed changes; but it also includes the larger impact to-date from updated license conditions (less generation) as well as additional outage time and spills in recent years. PG&E also accounted for the removal of mothballed units from the forecast.
2) The impacts of climate change under Shared Socioeconomic Pathway (SSP) greenhouse gas emissions scenario 3-7.0 reduce hydroelectric generation as the forecast period progresses.[98]
3) Expected FERC license conditions which result in less water allocated to hydroelectric generation.

[98] The CPUC requires IOUs to use the SSP 3-7.0 to be consistent with recent CPUC order (D.24-08-005) for planning purposes.

PG&E utilizes a fifteen-year performance average to mitigate year-to-year variability. It accounts for hydrological variability (e.g., cycle of droughts and wet years). Additionally, the CEC utilized a 15-year historic average assumption in their 2021 IEPR.[99]

B. Comparison to Updated Preferred System Portfolio

As described above, PG&E currently estimates its hydroelectric generation based on a future-adjusted fifteen-year average hydroelectric generation analysis. Compared to PG&E's future-adjusted fifteen-year average, the Conforming Portfolio assumes approximately 14 percent more generation from hydroelectric resources located within the CAISO.[100] The difference increases over time as PG&E assumes annual generation to decline through the modeled period due to FERC licensing conditions. This equates to approximately 3,300 GWh less in 2026 up to approximately 3,900 GWh in 2035. Given that PG&E's hydroelectric capacity represents a third of the CAISO's large hydroelectric capacity, PG&E recommends that the CPUC review and update as appropriate the expected generation from hydroelectric resources interconnected to the CAISO. Additionally, PG&E recommends the CPUC consider the impacts of climate change under the SSP 3-7.0, and account for changes in generation due to future unit relicensing. The expected performance and availability of PG&E's hydroelectric resources have not meaningfully changed since PG&E's 2022 LSE Plan submittal.

ii. System Reliability

A. Planning Assumptions for Hydro Reliability Supply

PG&E recommends the Commission utilize the monthly dispatchable hydroelectric Net Qualifying Capacity (NQC) values calculated based on the qualifying capacity (QC) methodology the Commission adopted in D.20-06-031 rather than the ELCC assumptions currently used within the RDT. The QC methodology accounts for hydrological variability and other operational constraints resulting in more representative reliability planning assumptions for hydroelectric resources, with resource-specific data included in the Commission's Master Resource Database.[101]

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[99] CEC Staff Members, Final 2021 IEPR, Volume III: Decarbonizing the State's Gas System, (Mar. 2022) p. F-2, <https://efiling.energy.ca.gov/GetDocument.aspx?tn=242233> (accessed August 3, 2026).

[100] Calculated based on PG&E's future-adjusted 15-year capacity factor of between 37 and 34 percent compared to RESOLVE's 33 percent for hydroelectric resources.

[101] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials

iii. Risks and Planning

A. GHG Emissions

As described above PG&E currently uses a future-adjusted fifteen-year performance average in its hydroelectric generation forecast to mitigate year-to-year variability, including the impacts of in-state drought. The future-adjusted fifteen-year average is used in the forecasts of GHG emissions, as well as energy production and expected costs.

B. Reliability Supply

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

C. Expected Costs

As with the energy and GHG emission forecasts discussed above, PG&E uses a recent future-adjusted fifteen-year performance average to forecast energy from hydroelectric generation to mitigate year-to-year variability. The cost risk associated with lower-than-forecasted energy production from the hydroelectric resources is not solely borne by PG&E's bundled customers because utility-owned hydroelectric resources are recovered through the PCIA rate. Since most customers in PG&E's service territory are subject to PCIA charges, PG&E's bundled customers are responsible for less than half of the above market cost from utility-owned hydroelectric resources.[102]

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

[102] Based on prescribed PG&E bundled customer sales assumption for the 2024-2026 IRP cycle.

D. Hedging and Contingency Planning

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

Beyond hedging short-term market price risk, PG&E has developed a risk mitigation plan regarding potential large uncontrolled water releases.[103] In its plan PG&E identifies potential risks for large uncontrolled water releases and proposed mitigation actions to address those risks. In addition to addressing safety concerns, the mitigation plan also reduces the potential for lost water supply and, therefore, an associated increase in future GHG emissions due to a reduction in hydroelectric generation.

i. Long-Duration Storage Development

PG&E is in discussions with providers of long-duration storage as part of its MTR and GHG Free solicitations, and is also pursuing a pilot project with a long-duration storage provider.

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

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

[103] PG&E's 2024 RAMP Report, A.24-05-008 (May 15, 2024), Chapter 11, Risk Assessment and Mitigation Strategy: Large Uncontrolled Water Release.

PG&E expects long-duration storage to present several benefits and risks if added to PG&E's bundled portfolio. Long-duration storage has the potential to provide capacity across more non-solar hours than traditional 4-hour batteries and would therefore be helpful to PG&E in closing its SoD position needs PG&E includes long-duration storage in its resource additions in the form of pumped storage, detailed in Section III.a, and these additions contribute to both GHG emissions targets and reliability planning. While LDES does contribute to reliability needs across more non-solar hours, longer duration batteries may also require additional charging hours.

j. Clean Firm Power Planning

PG&E identified a need for new clean firm capacity in its conforming portfolio as well as each of its alternative portfolios. As described in the Study Design section II.b.ii above, the bundled portfolios reflect PG&E's bundled need of the corresponding system portfolio for each scenario. Therefore, the clean firm capacity in PG&E's portfolio was economically selected by RESOLVE.

Table 30 shows the amount of new clean firm capacity selected for each of PG&E's portfolios, including by technology type and by year. Assuming some of this capacity is out-of-state, then PG&E would also have to procure additional import rights to ensure deliverability to CAISO; It is possible, but not certain, that this relatively small amount of capacity would require new transmission lines. All this clean firm capacity is incremental to the 2030-2032 procurement order, as PG&E assumes that order will be met exclusively with long-duration energy storage for IRP modeling purposes. PG&E discusses the potential for enhanced geothermal, nuclear, and carbon capture technologies to impact future electric system build below.

TABLE 30
BUNDLED PORTFOLIO CLEAN FIRM CAPACITY ADDITIONS BY SCENARIO

Line No.	Scenario	Technology	2030	2035	2040	2045
1	Scenario A	Geothermal	144	196	196	328
2		Nuclear	0	0	0	0
3	Scenario B	Geothermal	0	410	410	410
4		Nuclear	0	0	0	0
5	Scenario C	Geothermal	0	302	302	302
6		Nuclear	2,240	2,240	2,240	2,240
7	Scenario D	Geothermal	0	354	354	354
8		Nuclear	2,240	2,240	2,240	2,240

Comparison to 2022 IRP Filing

This marks a material change from PG&E's 2022 IRP filing which included no incremental clean firm capacity, nor did it include any scenarios where DCPP was extended beyond 2030. For 2026, RESOLVE optimally selected geothermal capacity in all scenarios. This is likely the result of multiple factors, including higher levels of existing solar and storage resources compared to 2022, as well as a load forecast that includes significant new baseload demand—both of which create a need for resources that can serve load 24 hours a day. While DCPP's extension is not considered as a candidate resource in RESOLVE, PG&E chose to model its extension to 2045 for Scenarios C and D since the value it provides as a large, clean firm resource already operating within the CAISO with no incremental transmission need, is unmatched. The extension of DCPP presents a least-regrets action that can reduce costs, lower new clean resource needs, and reduce emissions, helping California meet its decarbonization targets between now and 2045.

Geothermal

Despite the relatively low amount of geothermal capacity in PG&E's conforming portfolio, the resource potential is significant. CAISO territory has over 20 GW of EGS potential, including over 16 GW of potential in PG&E's territory alone.[104] Non-CAISO potential is even greater with approximately 48 GW combined in Nevada, Utah, Idaho, Oregon, and Northeast California.[105]

Clean firm technologies, such as EGS, may play a key role in California's energy future. As emission-free baseload resources, they are uniquely capable of supporting new large baseload customers without contributing to California's tightening cap on emissions. As California moves from a summer-peaking load curve to a dual summer- and winter-peaking curve, EGS could also meet new demand during the winter months, when solar is less available. However, there are significant barriers to integrating EGS into the CAISO grid, including from both in-state and out-of-state projects.

First, despite the tremendous in-state potential, California's lack of existing geologic exploration means geothermal developers assume more early-state exploration risk[106] when identifying

[104] 2026 IRP Inputs & Assumptions, p.67: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_slides-20260210.pdf (accessed August 3, 2026)

[105] Id.

[106] https://cdn.catf.us/wp-content/uploads/2026/05/20122941/California-Testbed-Report.pdf.

sites for new projects. Second, the permitting process in California is lengthy and expensive,[107] which further increases the development risk, especially for an emerging technology such as EGS.

In contrast, the US Department of Energy's (DOE) Frontier Observatory for Research in Geothermal Energy program mitigated much of the exploration risk in Utah and helped facilitate multiple gigawatts of EGS development. However, despite significant commercial interest in states like Nevada and Utah, there remain challenges in delivering the energy to California. Capacity on existing interstate transmission is limited and new interregional transmission lines often require approximately 10 years to build before they are operational.

As part of its FERC Order 1920 compliance filing, CAISO plans to transition from an annual transmission planning process to a biannual process, meaning the 27-28 transmission plan will be the last one published as part of its cadence, with CAISO's next transmission plan published in 2030. CAISO will also establish a new Long-Term Regional Planning process that will operate on a 4-year cadence, with its first plan also completed in 2030. As a result, any new interstate transmission not already underway, or not approved by the 27-28 transmission plan, is unlikely to come online in the early-to-mid 2030s. Unless these barriers are addressed, California could under-utilize EGS in addressing California's emerging load growth and ambitious emissions-reduction targets.

Nuclear

In contrast to the challenges above, the Diablo Canyon Nuclear Power Plant (DCPP) is already online and fully deliverable to California customers. While SB 846 prohibits LSEs from including DCPP in its preferred conforming portfolio, PG&E opted to model an alternative portfolio where DCPP stays online through 2045. As outlined in section III.n.i.C above, DCPP's extension could reduce the need for almost 11 GW of CAISO system capacity in 2035, including a reduction of almost 1.6 GW of replacement capacity in PG&E's bundled portfolio alone. DCPP is a fully deliverable, emissions-free resource that lacks development risk and would materially mitigate the infeasible build rates required to achieve the conforming portfolio. In addition to the emissions and reliability benefits, it also reduces costs for all CAISO customers, as outlined in Section III.e.

[107] https://cdn.catf.us/wp-content/uploads/2025/06/23162128/california-geothermal-report.pdf.

Carbon Capture and Sequestration

Although it does not qualify under the CPUC's description of clean firm for this filing, one key clean firm technology that is missing from the list of candidate resources in this Plan is carbon capture and sequestration (CCS). The 2022 California Air Resource Board (CARB) Scoping Plan, which underlies the GHG emissions constraints specified by the Commission for this Plan,[108] states that, "[CCS] will be a necessary tool to reduce GHG emissions and mitigate climate change while minimizing leakage and minimizing emissions where no technological alternatives may exist."[109] Furthermore, it states that while CCS is not applied to the electric sector until 2045, "an earlier application of CCS in the electricity sector would yield additional reductions in years prior to 2045."[110]

Given the importance in the Scoping Plan and as noted in its comments on the Commission's 26-27 TPP portfolios, PG&E recommends incorporating CCS as a retrofit candidate for existing natural gas plants. Given the declining natural gas generation in the forecast horizon, CCS retrofits should be modeled to determine what role technology may play in a future resource mix. PG&E understands that the Commission is currently working on incorporating this technology into the next TPP cycle[111] and urges the Commission to consider this technology in IRP modeling before procurement decisions are made for 2035 and beyond.

k. Non-CAISO, including Out-of-State, Wind Development

PG&E has identified additional out-of-state (OOS) wind generation resources within its Conforming and Alternative portfolios. As described in the Study Results section III.a.iii above, the conforming portfolio includes minimal new OOS wind through 2035, but it increases quickly to just over 1.7 GW and 2.3 GW of cumulative capacity by 2040 and 2045, respectively. These amounts reflect PG&E's approximate load share of the system results, which means the OOS wind in PG&E's portfolio was economically selected by RESOLVE. Therefore, consistent with RESOLVE's adherence to import limits for existing and approved transmission, no new interstate transmission lines are required to deliver the selected build in any of PG&E's conforming or alternative portfolios. PG&E's 2022 IRP portfolio included about 900 MW of cumulative new OOS wind by 2030, with no new OOS wind build by 2035. The reduced wind

[108] Ruling Finalizing Load Forecasts and Greenhouse Gas Emissions Benchmarks for 2026 IRP Filings (1/16/2026), page 5. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M595/K085/595085015.PDF

[109] 2022 CARB Scoping Plan, page 84. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp-es.pdf

[110] Id. at 86

[111] D.26-02-057, pages 58-59

selection in 2030 is likely due to a combination of factors including development of new transmission lines for deliverability,[112] the greater-than-expected increase in solar and storage build over the last few years, and the increasing congestion on Path 15 and Path 26 as all new OOS wind in 2030 will connect to the southern portion of CAISO's grid. Meanwhile, the increase in selected build by 2040 is likely due to the same factors driving the need for new clean firm – increasing solar and storage build, combined with new baseload demand, create a need for resources that can generate during non-solar hours. The RESOLVE-selected Path 15 and Path 26 upgrades will also reduce congestion by 2040 and provide deliverability to PG&E's service area.

PG&E does not have specific procurement activities for OOS wind, though it continues to monitor CAISO's regulatory processes, development of existing approved transmission lines, and the commercial prospects for wind technologies to be incorporated into PG&E's portfolio.

Generally, PG&E supports California accessing OOS wind as an option to meet its clean energy goals while ensuring system reliability and customer affordability, and PG&E itself is interested in investigating procurement of OOS wind to meet its own clean energy goals. However, with SWIP-North, TransWest Express (TWE), and SunZia all connecting to the southern portion of CAISO's grid, PG&E is concerned about deliverability to Northern California, especially as solar and storage development continues to expand faster in the south than in the north. RESOLVE has economically selected upgrades on Path 26 and Path 15 to help alleviate these deliverability constraints. Path 15 has been identified as a source of significant south-north congestion that may require more attention in future modeling efforts. For example, CAISO noted in their 25-26 Transmission Plan that "[t]hese results demonstrate conclusively that the Path 15 corridor now requires substantial reinforcement to alleviate congestion on this corridor."[113] PG&E will continue to monitor the regulatory processes and modeling efforts that support deliverability on Path 15 and Path 26 as prerequisites to OOS wind deliverability to PG&E's service area.

[112] CPUC's 2024-2026 IRP Inputs & Assumptions, p.79: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf (accessed August 3, 2026)

[113] CAISO's 2025-2026 Transmission Plan, p.126: https://stakeholdercenter.caiso.com/InitiativeDocuments/Board-Approved-2025-2026-Transmission-Plan.pdf (accessed August 3, 2026)

l. Offshore Wind Planning

PG&E has not identified any offshore wind generation resources in its Conforming or Alternative portfolios. Offshore wind capacity was not selected by RESOLVE in any of PG&E's modeling scenarios. This is a change from PG&E's 2022 IRP, which did include offshore wind in both its conforming and alternative portfolios. This change is driven by the technology's above-market costs preventing RESOLVE from economically selecting it. However, AB 1373 and D.24-08-064 gave the California Department of Water Resource (DWR) authority to procure up to 10.6 GW of long lead time resources on behalf of the state, including up to 7.6 GW of offshore wind if procured at the right cost. If DWR is successful in its solicitations, it would still be possible for offshore wind to show up in future portfolios.

m. Transmission Development

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

For its conforming portfolio, and all alternative portfolios, PG&E made generic resource additions to meet its 2035, 2040, and 2045 emissions benchmarks. These resources do not yet have an interconnection queue position. To ensure that the generic resources are a part of the Commission's next Preferred System Portfolio, PG&E limited the candidate resources available to meet PG&E's open GHG position to those chosen at the system level by the RESOLVE model. Therefore, PG&E's transmission assumptions are consistent with the CPUC's 2026 IRP Inputs and Assumptions regarding transmission costs and availability. This result is similar to PG&E's 2022 IRP submittal which also included only resources chosen at the system level by the RESOLVE model.

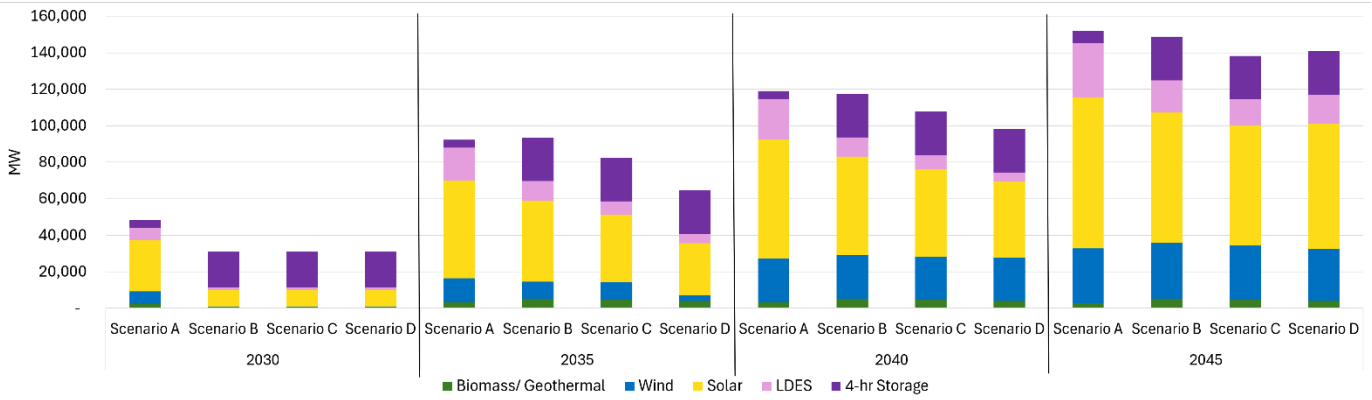
Going forward, the actual transmission need and related cost will be available after CAISO's assessment in the next TPP based on the CPUC's aggregated IRP portfolio. Given the need for new clean firm resources, and the evolving locations and conditions under which they may be available, it is likely that transmission needs will change as well, and additional transmission investment may be required to interconnect and reliably integrate these resources into the CAISO system. Notably, RESOLVE economically selected Path 26 upgrades in all PG&E's IRP scenarios, including the conforming scenario and all three alternative scenarios. In the conforming scenario, RESOLVE selected upgrades of 1 GW by 2035, 2.2 GW by 2040, and 3.5 GW by 2045. The need for deliverability into Northern California is clear, and CAISO's ability to plan for these upgrades is important in ensuring reliability, affordability, and emissions-reductions for customers in PG&E's territory. This risk of resource selection without

deliverability may be exacerbated by evolving inputs and assumptions on commercial interest in clean firm technologies like conventional geothermal and EGS. For example, RESOLVE still selected significant quantities of in-state geothermal despite minimal commercial interest. If geothermal development follows existing commercial interest and materializes out of state, instead of in California, the need for Path 26 upgrades may increase further, or deliverability to northern California may even be infeasible without an alternative path to deliverability beyond what has been proposed to date. One way to reduce Path 26 upgrade need and support deliverability into northern California could be to consider new transmission alternatives that connect directly to the PG&E TAC Area. PG&E will continue monitoring regulatory processes that address this risk, including the busbar mapping effort at the Commission as well as the transmission planning process and corresponding transmission development at CAISO.

n. CAISO System Modeling Results

This section presents the CAISO system modeling results for each of PG&E's scenarios. A summary of the results is presented in the figure below with details in the following subsections.

FIGURE 13
SUMMARY OF INCREMENTAL INSTALLED CAPACITY BY SCENARIO (MW)



i. Summary of Results by Scenario

A. Scenario A: Conforming Assumptions

TABLE 31
SCENARIO A: CONFORMING ASSUMPTIONS SYSTEM PORTFOLIO RESULTS

CAISO Planned & RESOLVE-Selected Capacity (GW)						
Resource Type	2026	2028	2030	2035	2040	2045
Natural Gas	-	-	-	-	-	-
Geothermal	0.1	0.6	2.4	3.2	3.2	3.2
Geothermal (Enhanced)	-	-	-	-	-	0.7
Biomass	0.0	0.0	0.0	0.0	0.0	0.0
In-State Wind	0.3	0.8	1.3	6.3	8.3	10.9
Out-of-State Wind	1.4	4.0	5.5	7.0	15.8	19.0
Offshore Wind	-	-	-	-	-	-
Solar	4.0	12.0	28.1	53.4	65.3	82.7
Li-ion Battery (4-hr)	2.3	4.4	4.4	4.4	4.4	6.8
Li-ion Battery (8-hr)	0.1	1.7	6.4	14.0	14.0	21.1
Location Constrained Storage (12-hr)	-	-	0.3	3.9	8.0	8.5
Generic Storage (12-hr)	-	-	-	-	-	-
Generic Storage (24-hr)	-	-	-	-	-	-
Generic Storage (100-hr)	-	-	-	-	-	-
Shed DR	-	-	-	-	-	-
Total New Resources	**8.2**	**23.5**	**48.5**	**92.3**	**119.1**	**153.0**
Total CAISO Emissions (MMT)	37.5	30.9	24.3	20.3	13.8	7.4
Total GHG Abatement Cost ($/tCO2)	$172	$452	$267	$369	$228	$223
Achieved Renewable Portfolio Standard (%)	64%	76%	89%	97%	101%	108%
Achieved CES Clean Generation (%)	76%	87%	99%	104%	108%	114%

As described in the Alternate Assumptions section, Scenario A is fully aligned with the 2024–2026 IRP Inputs and Assumptions report. The results above summarize selected resource capacity over the modeled period. From 2026 through 2030, the model selects 48.5 GW of cumulative new capacity, equivalent to an average build rate of 9.7 GW per year. Of this total, 34.9 GW consists of renewable resources, corresponding to an average of 7.0 GW of renewable additions annually. By comparison, CAISO has added an average of 2.0 GW of new renewable

capacity per year over the past two years.[114] Achieving the Scenario A Portfolio would therefore require more than tripling the current build rate for renewable resources in the near term. By 2045, Scenario A selected 3.9 GW of clean firm capacity, including 0.6 GW of in-state EGS and 0.1 GW of out-of-state EGS.

In the 2026 IRP RESOLVE model, IOUs within CAISO and the transmission interfaces between them are modeled individually.[115] Transmission upgrades between PG&E and SCE service territories (Path 26 and Path 15) can be selected in both directions across three tranches: up to 1,000 MW in 2035, 2,500 MW in 2038, and 5,500 MW in 2040. In the Conforming Portfolio, the model selected cumulative transmission upgrades of 1,000 MW in 2035, 2,202 MW in 2040, and 3,512 MW in 2045. These upgrades correspond to a total cost of $3.9 billion ($0.7 billion in 2035, an additional $1.6 billion in 2040, and an additional $1.6 billion in 2045).

The model exceeds the RPS and Clean Energy Standard (CES) requirements in every modeled year and meets the GHG emissions target, which is the binding constraint. GHG abatement costs are substantial, reaching $452/ tCO_2 in 2028 and remaining above $200/ tCO_2throughout the modeled period. GHG abatement costs modeled here over the next 10 years are 5-10x more expensive than the equivalent costs in other key GHG abatement programs in California (i.e., $30/ tCO_2 for cap-and invest,[116] and $70/ tCO_2 for LCFS[117]) and at least double the GHG abatement costs over the next 10 years from clean electricity in the 30 MMT Alternative Scenario in CARB's Scoping Plan.[118]

[114] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-december-2025-release.pdf.

[115] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf (accessed August 3, 2026)

[116] https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/program-data/cap-and-trade-program-data-dashboard#Figure2 (accessed June 25, 2026).

[117] https://ww2.arb.ca.gov/resources/documents/weekly-lcfs-credit-transfer-activity-reports (accessed June 25, 2026).

[118] Table C-28 at https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-appendix-c-ab-197-measure-analysis.pdf.

B. Scenario B: Alternative #1, Market-Informed Resource Expansion

TABLE 32
SCENARIO B: MARKET-INFORMED RESOURCE EXPANSION SYSTEM PORTFOLIO RESULTS

CAISO Planned & RESOLVE-Selected Capacity (GW)						
Resource Type	2026	2028	2030	2035	2040	2045
Natural Gas	-	-	-	-	-	-
Geothermal	0.0	0.1	0.1	3.3	3.3	3.3
Geothermal (Enhanced)	-	-	-	1.9	1.9	1.9
Biomass	0.0	0.0	0.0	0.0	0.0	0.0
In-State Wind	0.1	0.4	0.7	3.4	9.0	11.7
Out-of-State Wind	-	-	-	5.9	15.0	19.0
Offshore Wind	-	-	-	-	-	-
Solar	1.8	5.5	9.1	44.4	53.8	71.3
Li-ion Battery (4-hr)	3.9	11.7	19.5	23.9	23.9	23.9
Li-ion Battery (8-hr)	0.3	0.9	1.5	7.0	7.0	14.0
Location Constrained Storage (12-hr)	-	-	-	3.5	3.5	3.5
Generic Storage (12-hr)	-	-	-	-	-	-
Generic Storage (24-hr)	-	-	-	-	-	-
Generic Storage (100-hr)	-	-	-	-	-	-
Shed DR	-	-	-	-	-	-
Total New Resources	**6.2**	**18.6**	**30.9**	**93.3**	**117.4**	**148.6**
Total CAISO Emissions (MMT)	43.0	44.6	51.1	20.3	13.8	7.4
Total GHG Abatement Cost ($/tCO2)	$27	$30	$33	$318	$335	$434
Achieved Renewable Portfolio Standard (%)	58%	61%	60%	96%	100%	106%
Achieved CES Clean Generation (%)	70%	73%	70%	104%	106%	112%

Scenario B replaces the 2026 IRP Filing Requirements resource cost assumptions with those from the 26-27 TPP and applies near-term build limits as described in the Alternate Assumptions section.

Applying the 26-27 TPP cost assumptions results in a more diversified resource mix. The expiration of federal tax credits increases solar and wind costs beginning in 2030, making EGS more cost competitive. As a result, EGS is selected earlier and at higher levels in Scenario B (1.9 GW of EGS selected by 2035) than Scenario A (0.7 GW of EGS selected by 2045). Within the new EGS capacity, the amount of out-of-state EGS increases from 0.1 GW in Scenario A to

0.7 GW in Scenario B. The increased deployment of clean firm resources reduces the need for solar and LDES.

Limiting the near-term build rate to the historical average reduces total capacity additions between 2026 and 2030 (48.5 GW in Scenario A versus 30.9 GW in Scenario B). This reduction is observed across all technology types, with the exception of 4-hour li-ion batteries. Consistent with recent historical trends and market availability, 4-hour li-ion battery storage makes up a significant portion of new capacity additions between 2026-2030. As a result, more 4-hour li-ion battery storage is selected in Scenario B (19.5 GW) compared to Scenario A (4.4 GW). Consequently, in the later years when the model can select new resources beyond the build constraint, fewer LDES resources are added to the portfolio.

Between 2030 through 2035, the build rate accelerates to an average of 12.5 GW per year to achieve the 2035 GHG emissions target. As a result, GHG abatement costs are significant, remaining above \$300/ tCO_2 in the 2030s and reaching \$434/ tCO_2 in 2045.

Scenario B results in 527 MW less Path 26 and Path 15 transmission buildout by 2040 but requires an additional 869 MW by 2045. Under Scenario B assumptions, the RESOLVE model selects cumulative transmission upgrades of 1,000 MW by 2035, 1,674 MW by 2040, and 4,382 MW by 2045. These upgrades correspond to approximately \$0.7 billion in 2035, an additional \$0.9 billion by 2040, and \$3.4 billion by 2045. In total, this represents \$4.9 Billion in Path 15 and 26 upgrade costs, an additional \$1.1 billion relative to Scenario A.

C. Scenario C: Alternative #2, Scenario B plus 2045 Diablo Canyon Extension

TABLE 33
SCENARIO C: SCENARIO B PLUS 2045 DIABLO CANYON EXTENSION SYSTEM PORTFOLIO RESULTS

CAISO Planned & RESOLVE-Selected Capacity (GW)						
Resource Type	2026	2028	2030	2035	2040	2045
Natural Gas	-	-	-	-	-	-
Geothermal	0.0	0.1	0.1	3.3	3.3	3.3
Geothermal (Enhanced)	-	-	-	1.4	1.4	1.4
Biomass	0.0	0.0	0.0	0.0	0.0	0.0
In-State Wind	0.1	0.4	0.7	3.6	9.0	10.7
Out-of-State Wind	-	-	-	5.9	14.7	19.0
Offshore Wind	-	-	-	-	-	-
Solar	1.8	5.5	9.1	36.8	47.9	65.6
Li-ion Battery (4-hr)	3.9	11.7	19.5	23.9	23.9	23.9
Li-ion Battery (8-hr)	0.3	0.9	1.5	4.0	4.0	10.7
Location Constrained Storage (12-hr)	-	-	-	3.5	3.5	3.5
Generic Storage (12-hr)	-	-	-	-	-	-
Generic Storage (24-hr)	-	-	-	-	-	-
Generic Storage (100-hr)	-	-	-	-	-	-
Shed DR	-	-	-	-	-	-
Total New Resources	**6.2**	**18.6**	**30.9**	**82.4**	**107.6**	**138.2**
Total CAISO Emissions (MMT)	37.0	38.6	45.0	20.3	13.8	7.4
Total GHG Abatement Cost ($/tCO2)	$27	$30	$33	$270	$323	$446
Achieved Renewable Portfolio Standard (%)	58%	61%	60%	89%	94%	101%
Achieved CES Clean Generation (%)	78%	79%	76%	103%	106%	112%

Scenario C incorporates the two assumption changes from Scenario B (replacing the 2026 Filing Requirements resource cost assumptions with the 2026–2027 TPP assumptions and limiting near-term build) and extends DCPP operations through 2045. This allows the impact of extending DCPP to be isolated.

Between 2026-2030, when new build is limited, extending DCPP results in lower total CAISO emissions. CAISO GHG emissions are 6.0 MMT lower in 2026, 6.1 MMT lower in 2028, and 6.2 MMT lower in 2030 in Scenario C compared to Scenario B. When the model can begin selecting new resources beyond the near-term limits, the extension of DCPP lowers the amount of new build and the total system costs. The cumulative new build is 11.0 GW lower in 2035,

9.8 GW in 2040, and 10.4 GW in 2045 in Scenario C than in Scenario B. By 2045, the avoided build includes 0.5 GW of in-state EGS, 0.9 GW of in-state wind, 5.7 GW of solar, and 3.2 GW of 8-hour li-ion battery. This reduced build results in $2.0-2.1 Billion in annual system cost savings, which is offset by approximately $1 billion in DCPP costs. As a result, total system cost is approximately $1.0-1.1 Billion less annually in Scenario C than Scenario B starting in the early 2030s. Overall, extending DCPP operations through 2045 represents a least regrets strategy for the State to reduce costs, maintain progress toward decarbonization, and minimize the need for new resources to achieve policy targets.

Extending DCPP reduces GHG abatement costs by $47/ tCO_2 in 2035 and $12/ tCO_2 in 2040 relative to Scenario B but increases costs by $13 in 2045.

Extending DCPP through 2045 reduces the need for new Path 26 and Path 15 transmission buildout relative to both Scenario A and Scenario B, as the plant is located north of Path 26. Under Scenario C assumptions, the RESOLVE model selects cumulative transmission upgrades of 1,000 MW by 2035, 1,000 MW by 2040, and 2,854 MW by 2045. This upgrade corresponds to approximately $0.7 billion in 2035, no additional costs in 2040, and $2.4 billion in 2045. In total, Path 15 and Path 26 upgrade costs are $3.1 billion, representing $0.8 billion in savings relative to Scenario A and $1.9 billion relative to Scenario B.

D. Scenario D: Alternative #3, Scenario C plus Modified Interim GHG Emission Targets

TABLE 34
SCENARIO D: SCENARIO C PLUS MODIFIED INTERIM GHG EMISSION TARGETS SYSTEM PORTFOLIO RESULTS

CAISO Planned & RESOLVE-Selected Capacity (GW)						
Resource Type	2026	2028	2030	2035	2040	2045
Natural Gas	-	-	-	-	-	-
Geothermal	0.0	0.1	0.1	3.3	3.3	3.3
Geothermal (Enhanced)	-	-	-	0.6	0.6	0.6
Biomass	0.0	0.0	0.0	0.0	0.0	0.0
In-State Wind	0.1	0.4	0.7	2.4	9.0	9.3
Out-of-State Wind	-	-	-	0.8	14.8	19.0
Offshore Wind	-	-	-	-	-	-
Solar	1.8	5.5	9.1	28.4	41.5	68.5
Li-ion Battery (4-hr)	3.9	11.7	19.5	23.9	23.9	23.9
Li-ion Battery (8-hr)	0.3	0.9	1.5	1.5	1.5	12.5
Location Constrained Storage (12-hr)	-	-	-	3.4	3.4	3.4
Generic Storage (12-hr)	-	-	-	-	-	-
Generic Storage (24-hr)	-	-	-	-	-	-
Generic Storage (100-hr)	-	-	-	-	-	-
Shed DR	-	-	-	-	-	-
Total New Resources	**6.2**	**18.6**	**30.9**	**64.4**	**98.1**	**140.6**
Total CAISO Emissions (MMT)	37.0	38.6	45.0	33.8	18.6	7.4
Total GHG Abatement Cost ($/tCO2)	$27	$30	$33	$143	$218	$461
Achieved Renewable Portfolio Standard (%)	58%	61%	60%	77%	90%	101%
Achieved CES Clean Generation (%)	78%	79%	76%	91%	102%	112%

Scenario D includes the three assumption changes made in Scenario C (replaces the 2026 Filing Requirements resource cost assumptions with the 26-27 TPP resource cost assumptions, limits the near-term build, and extends the operations of DCPP through 2045) and modifies the GHG emission target through 2040 as described in the Alternate Assumptions section. This allows the impact of modifying the GHG emissions target on the portfolio to be isolated.

Scenario D's GHG emissions exceed the target by 13.5 MMT in 2035 and 4.8 MMT in 2040. Because the GHG target is the binding constraint, higher allowable emissions in the 2030s

reduce the need for new resource capacity additions, resulting in lower build during this period. Total installed capacity converges to a similar level to Scenario C by 2045 as the GHG emission target is unchanged in this year. This delay in resource deployment results in cost savings, as capacity additions can occur later when capital costs are lower.

In 2035, total selected capacity is 18.0 GW lower relative to Scenario C, driven primarily by reductions in solar (8.4 GW), out-of-state wind (5.2 GW), 8-hour lithium-ion storage (2.5 GW), in-state wind (1.2 GW), and EGS (0.7 GW), resulting in $1.5 billion in total annual resource cost savings. By 2040, selected capacity remains 8.6 GW lower, with reductions concentrated in solar (6.4 GW), 8-hour lithium-ion storage (2.5 GW), and EGS (0.7 GW), partially offset by a modest 0.2 GW increase in wind. This results in $800 million annual cost savings in 2040. By 2045, installed capacity for Scenario D slightly exceeds Scenario C by 2.5 GW, reflecting increases in wind (3.0 GW) and 8-hour lithium-ion storage (1.7 GW), offset by reductions in in-state wind (1.4 GW) and EGS (0.7 GW). Although total installed capacity reaches levels comparable to Scenario C by 2045, Scenario D still achieves annual cost savings of $479 million by deferring resource additions until later years when costs are projected to be lower.

Modifying the GHG target reduces GHG abatement costs by $127/ tCO_2 in 2035 and $105 in 2040 relative to Scenario C but increases costs by $14/ tCO_2 in 2045.

Modifying the GHG emissions target reduces the need for new Path 26 and Path 15 transmission buildout in 2035, but increases it in the longer term relative to Scenario C. Under Scenario D assumptions, the RESOLVE model selects cumulative transmission upgrades of 0 MW in 2035, 1,000 MW by 2040, and 3,548 MW by 2045. This upgrade corresponds to total costs of $0 in 2035, $0.7 billion in 2040, and $3.2 billion in 2045. Overall, Path 15 and Path 26 upgrade costs total $3.9 billion, which is comparable to Scenario A and $0.9 billion higher than Scenario C.

IV. Action Plan

The action plan described herein demonstrates how PG&E's near-term activities align with its planning and procurement strategy, outlines current and planned activities to address DACs, and notes what actions PG&E is requesting from the Commission to facilitate effective implementation of its 2026 IRP. Each subsection of the action plan provides a clear overview of PG&E's progress toward achieving its GHG compliance targets and in providing valuable contributions in meeting California's clean energy goals in a safe, reliable, and cost-effective manner.

Based on the study objectives and results of PG&E's IRP analysis, this section presents PG&E's activities to procure the resources identified in its Conforming and Alternative Portfolio scenarios. To meet the goals laid out in its study design section, PG&E anticipates the need for an additional 12-17 TWh[119] of energy by 2035. Prior to this IRP filing, PG&E had already begun procuring incremental resources to meet its future IRP clean energy needs and CPUC ordered reliability procurement. PG&E believes it is prudent to continue soliciting resources to meet these and future portfolio needs and is therefore requesting continued procurement authorization from the Commission in this filing. The exact quantity and types of resources PG&E will ultimately procure to satisfy its procurement needs may vary depending on the resource mix, changes in load forecast, outcomes of ongoing regulatory proceedings, or procurement resulting from future mandates. Furthermore, PG&E sees it prudent to consider procuring resources with attributes similar to firm zero emitting ones—this includes longer lead time resources such as enhanced geothermal that may need system upgrades including new transmission build out to be viable within a useful timeframe. These resources may meet unique portfolio needs, provide additional value and help build greater diversity. In the interim PG&E feels that it is important to not only look to incremental procurement of more readily available resources but also extend the life of existing ones to bridge the gap until these resources are available or can come online. Ultimately, PG&E's goal is to procure these incremental resources in a measured approach to mitigate potential risks with future events, developments, and forecast adjustments.

[119] Values are gross energy volumes based on Scenarios B, C and D in Study Analysis. Curtailment assumptions from the CSP tool are applied to gross volumes to determine net generation for emissions goals.

a. Proposed Procurement Activities and Potential Barriers

The sections below describe PG&E's supply side procurement activities (e.g., renewable energy and energy storage) as well as demand side procurement activities that are not otherwise reflected in the supply side tables of this report.

i. Resources to meet IRP mandated procurement requirements, including D.21-06-035, D.23-02-040 and D.26-02-057

Mid-Term Reliability (MTR) Request for Offers (RFOs): On June 30, 2021, the CPUC issued D.21-06-035. In D.21-06-035, the Commission requires incremental procurement of 11,500 MW of additional Net Qualifying Capacity (NQC) resources, of which PG&E is responsible for 2,302 MW for its bundled service customer portion. The decision requires that at least 2,000 MW be online by August 1, 2023, an additional 6,000 MW by June 1, 2024, an additional 1,500 MW by June 1, 2025, and an additional 2,000 MW by June 1, 2026. Further, D.21-06-035 requires that at least 2,500 MW of resources procured collectively by the LSEs, between 2023 and 2025, be either zero emissions generation resources, generation resources paired with storage, or demand response, to replace the current supply of energy from the Diablo Canyon Power Plant (DCPP). This is to ensure there are no GHG emissions increases upon DCPP's retirement.

PG&E issued its MTR RFO – Phase 1 on June 18, 2021, to solicit offers to procure incremental NQC resources with an expected online date of August 1, 2023, and June 1, 2024, which will count towards PG&E's procurement requirement of a total of 1,601 MW by June 1, 2024. This solicitation resulted in the execution of nine agreements, all of which were approved by the Commission via Resolution E-5202.

PG&E issued its MTR RFO – Phase 2 on April 15, 2022, to solicit offers to procure incremental NQC resources to provide system-level qualifying NQC with online dates beginning June 1, 2024 through June 1, 2026 depending on the category. This solicitation resulted in the execution of four agreements which were approved by the Commission via Resolutions E-5262, E-5263, and E-5297.

In anticipation of Commission adoption of D.23-02-040, PG&E issued its third solicitation, MTR RFO - Phase 3 on February 7, 2023, seeking resources that could come online in 2026 and 2027 and meet the requirements of such decision. PG&E reopened the MTR RFO – Phase 3 multiple times in an attempt to identify additional projects that could meet the requirements of D.23-02-040. This solicitation resulted in the execution of 10 agreements, which were all approved by the CPUC via Resolutions E-5325, E-5370, E-5345, E-5377, and E-5409.

On October 15, 2024, PG&E issued its Long Lead Time solicitation, seeking to procure long duration energy storage projects and firm zero-emitting projects, as directed by D.21-06-035. This resulted in the execution of one long duration energy storage project which was approved by the CPUC via Resolution E-5437.

GHG-Free RFO: On February 27, 2026, the CPUC issued D.26-02-057. In D.26-02-057, the CPUC orders PG&E to procure 1,077 MW of incremental NQC by 2032 for its bundled service customers. The decision requires that at least 359 MW be online by June 1, 2030, an additional 359 MW by June 1, 2031, and an additional 359 MW by June 1, 2032. Further, the decision requires that 269 MW consist of long-duration energy storage (LDES) (eight hours or greater) and/or clean-firm resources and all resources be GHG-free, including zero-emitting and/or RPS-eligible resources that are incremental to the IRP baseline. This is to meet identified system reliability needs for the 2029-2032 timeframe. Compliance provisions under the decision mirror prior MTR orders, including the availability of a three-year grace period to address procurement delays, subject to specified conditions.

PG&E issued its initial GHG-Free RFO on June 17, 2025, to solicit offers for eligible GHG-free resources to meet requirements set forth in SB 100 and SB 1020, GHG emission reductions goals, and IRP planning goals and requirements. PG&E subsequently re-issued the GHG-Free RFO on February 20, 2026, to seek additional resources that could meet the requirements of D.26-02-057, including long duration energy storage and clean firm resources. PG&E expects that any resources procured through its GHG-Free RFO will be incremental and thus contribute towards applicable IRP mandated procurement requirements, including D.21-06-035, D.23-02-040 and D.26-02-057.

ii. Plans for resources that are currently non-candidate in CPUC's IRPs not described above

PG&E's recent GHG-Free RFO was an all-resource solicitation that sought all types of GHG-free resources including some resources that are not currently considered candidate resources in the Commission's IRP. This includes emerging technologies such as Carbon Capture and Sequestration (CCS) facilities. PG&E's strategy for any solicitation is to use its Least-Cost Best-Fit (LCBF) methodology to determine which resources that bid into its RFO best meet its portfolio needs at least cost for its customers. Should PG&E's evaluation determine that non-candidate resources are the best fit for its portfolio, it may choose to pursue these options. Given that the counting rules for some emerging technologies (such as CCS) are not well defined, PG&E asks that determinations be made sooner than later to better inform procurement.

iii. Other renewable and/or zero carbon resources not described above

This section includes PG&E procurement activities (including near-term actions), potential barriers, and resource viability for renewable resources for PG&E's Conforming and Alternative Scenarios as shown in Tables 10 - 14.

PG&E will continue to meet its RPS requirements as established by the California Legislature. As shown in its Draft 2026 RPS Plan,[120] PG&E does not anticipate having an immediate procurement need should it be able to use its RPS Bank. However, given uncertainty on the cost of bank usage[121] and the need for incremental RPS resources to meet other portfolio needs, such as PG&E's IRP requirements, PG&E requested procurement authority therein.[122] In addition to this request, PG&E submitted an updated Bundled Procurement Plan (BPP)[123] on June 1, 2026, requesting streamlined authority to procure certain short-term RPS products. Authority to flexibly procure now will help PG&E mitigate against risks such as a supply constrained market, project development delay or failure, changes in local, state or federal policy, load volatility or changes in need year. The procurement request in this IRP filing of roughly 4.6 to 6.6 GW[124] of incremental capacity by 2035 is inclusive of the RPS procurement request made earlier this year in PG&E's Draft 2026 RPS Plan. However, the request herein

[120] See PG&E's Draft 2026 RPS Plan (June 12, 2026), Section VIII, Renewable Net Short (RNS) Calculation, for more details on PG&E's RNS position, https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=877764 (accessed August 3, 2026)

[121] Id., Section II, *Executive Summary* of PG&E's Draft 2026 RPS Procurement Plan. As noted there, the CPUC is currently considering Rulemaking (R.)25-02-005 to determine whether bundled service customers must compensate departing load customers when PG&E uses its Pre-2019 Banked REC volumes for RPS compliance needs. Should a determination in R.25-02-005 result in Bank usage not being the most cost-effective means of meeting RPS compliance, PG&E may have a sooner need to procure incremental RPS products or resources to meet compliance at lower costs.

[122] Id. Section II.D, *PG&E Requests for Relief Arising from 2026 RPS Plan*, Draft 2026 RPS Procurement Plan has details on PG&E's requested Procurement Authority.

[123] R.25-06-019, Electric Integrated Resource Planning Oversight OIR, PG&E's Proposed Updated BPP-PUBLIC: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K066/608066401.PDF

[124] Values represent nameplate capacity based on Study Analysis for scenarios B, C and D and include storage (e.g. battery and pumped storage) capacity. These values exclude CPE allocations shown in resource addition tables in the study results sections. The ultimate quantity of resources procured may vary as a result of changes to underlying demand forecasts, requirements, resource mix or other factors. This procurement request is to begin procurement towards these needs regardless of such changes.

provides additional detail on the volume sought reflecting other planning and legislative procurement drivers associated with IRP goals and the associated planning process compared to the RPS plan request. Table 35 below provides a summary of PG&E's renewable energy actions, barriers and recommendations.

TABLE 35
RENEWABLE ENERGY – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS

Existing Near-Term Actions	• Administer ReMAT program. • Bioenergy Renewable Action Mechanism (BioRAM) procurement. • Administer AB 1613 program. • DAC solicitations twice a year. • Administer Public Utility Regulatory Policies Act (PURPA) procurement. • Continue allocations, purchases and sales of RPS products • Renegotiate existing contracts including, but not limited to, contract price reductions, extensions of contract terms, increased buyer curtailment flexibility, repowers of existing facilities, contract terminations, and/or upgrades of existing facility equipment or combinations of the foregoing.
Key Barriers	• Load forecast uncertainty, including new electrification load, data center load, and load migration. • Delays in achieving expected online dates. • Limited availability for long lead time and/or emerging technologies. • Federal policy changes including changes to investment and production tax credits and tariffs impact cost of candidate resources.
Proposed New Near-Term Actions/ CPUC Direction	• PG&E has submitted a request for renewable energy procurement in its Draft 2026 RPS Plan. • PG&E is requesting continued procurement authority in this IRP filing. • The CPUC should reconsider the feasibility of current 2030 emissions requirements for customer affordability and build-rate feasibility reasons. • The CPUC should not issue interim procurement orders until a decision on the RCPPP is made. This decision should be informed by customer affordability and build-rate feasibility.
Deviations From Current Resource Plans	No deviations.
Recommendation for Future IRPs	The CPUC should continue to model RPS resources as candidate resources.

Existing Near-Term Actions

PG&E is also managing the following procurement activities and programs, which impact RPS procurement:

BioMAT Program: In accordance with D.20-08-043 and the BioMAT Tariff, the BioMAT Program has sunset as of December 31, 2025. Projects remaining in the queue were given 90 days following the sunset to accept the price. Any resulting, final BioMAT Power Purchase Agreements (PPAs) would be executed thereafter in 2026. PG&E will continue to administer its BioMAT PPAs, which include waste management, dairy/agriculture, and sustainable forest management projects. PG&E has procured 34 MW under this program.

ReMAT Program: PG&E will continue to administer its ReMAT program for renewable peaking, non-peaking, and baseload resources. On December 17, 2021, the CPUC issued D.21-12-032, resolving several outstanding petitions for modification. Among other program changes, the decision allows renewable facilities enhanced with storage to participate and revises the program end date to when remaining capacity in the program reaches 0.99 MW or less. Through ReMAT, PG&E is required to procure a total of 218.8 MW of renewable resources. Currently PG&E has procured 113 MW, which includes capacity procured under the predecessor programs E-SRG and E-PWF.

BioRAM Procurement: Implementing SB 1109, the CPUC issued Resolution E-5288 in 2023, ordering PG&E to offer a contract extension for its existing BioRAM contracts. In December 2025, PG&E executed a contract extension amendment with one of its BioRAM counterparties, Shasta – Sustainable Resource Management, but was not able to reach agreement for its other BioRAM contract, Burney Forest Products. In April 2025, the CPUC issued Resolution E-5376 requiring PG&E to again offer an extension to Burney. In December 2025, PG&E executed a contract extension amendment with Burney Forest Products and sought CPUC approval of the amendment via Advice Letter 7796-E, which is currently under review by the CPUC. PG&E is in compliance with the CPUC's resolutions regarding BioRAM procurement.

AB 1613 Program: In compliance with D.09-12-042, the AB 1613 contract remains available for efficient CHP facilities.

DAC Solicitations: In compliance with D.24-05-065, PG&E holds one annual solicitation to procure new solar PV resources for the Disadvantaged Communities Green Tariff (DAC-GT) program until its remaining capacity is met. D.24-05-065 also closed the Community Solar Green Tariff (CS-GT) portion of the DAC program and consolidated program allocation into the DAC-GT program. PG&E's allocation, set by E-4999 and D.24-05-065 and adjusted for transfers

to CCAs, is 81.43 MW. As of September 23, 2025, 28.11 MW of procurement need remains. Offers received by PG&E in its most recent DAC-GT solicitation, issued September 23, 2025, are currently under evaluation.

GTSR Solicitations: D.24-05-065 revised the GTSR Program by closing the Enhanced Community Renewables (ECR, branded *Regional Renewable Choice*) tariff and restructuring the Green Tariff (GT, branded *Solar Choice*) into the new "Modified GT" program. Under this Decision, all unprocured ECR capacity was reassigned to the Modified GT, and a statewide cap of 562 MW was established for the program. Under the Modified GT, customers subscribed to the program remain on their otherwise applicable tariff and are "topped off" to achieve 100 percent clean energy. Pursuant to D.24-05-065, while participation in the Modified GT must still result in commensurate, incremental green power generation, the modified program does not require a strict, direct causation between customer enrollment and program-specific procurement. However, solicited resources must be incremental to RPS resources, not merely unallocated RPS. Pursuant to Advice Letter 7670-E, which was accepted by the CPUC on September 6, 2025, PG&E has paused its procurement activities required by D.21-12-036; PG&E will detail in its advice letter implementing the Modified GT (due October 15, 2026) how procurement for the program will result in incremental new renewable energy being purchased to serve subscribed customers.

PURPA: In compliance with D.20-05-006, the Standard Offer PURPA contract remains available to Qualifying Facilities.

Continue Sales of Bundled RPS Volumes as Needed: Pursuant to PG&E's Draft 2026 RPS Procurement Plan, PG&E continues to consider RPS sales as a tool to manage its portfolio. RPS sales can help PG&E balance its position and create additional value for bundled customers via sales revenues. The volume of RPS sales PG&E may seek to execute is dependent on several factors including overall portfolio needs, customer affordability, market demand, pricing and potential cost of using RPS Bank.

Key Barriers

Load forecast uncertainty, including data center load: PG&E's RPS procurement need is a function of its forecasted bundled service retail sales. While forecasted retail sales may change, some factors that can cause uncertainty include future load departure or return, Electric Vehicle (EV) adoption rates, electrification, energy efficiency technologies and large load customers such as data centers. Data centers pose a specific challenge in planning given the size of projected projects and uncertainty of LSEs serving them. Any change to project size, timeline, or LSE provider may significantly impact PG&E's Bundled retail sales forecast and

consequently its anticipated procurement need. In addition, as the Provider of Last Resort (POLR), PG&E may be obligated to serve large load customers with short notice, such as in the event of an involuntary return of a specific Community Choice Aggregator's (CCA) customer or a mass involuntary return to PG&E service.

Delays in achieving expected online dates: Project development delays, such as interconnection and network upgrades, can cause delays in achieving expected online dates, including projects that may lack the transmission infrastructure required for deliverability. PG&E accounts for some level of project delay and failure in its planning processes and its overall portfolio management strategy.

Limited Availability for Long-Lead Time / Emerging Technologies: Limited availability of projects that require extended development timelines and/or emerging technologies can impact PG&E's ability to secure such resources to fulfill its portfolio needs. As detailed in Advice Letter 7608-E, PG&E has recently encountered challenges procuring such projects, particularly firm-zero emitting resources, as part of its efforts to meet IRP procurement mandates due to the limited market availability of eligible technologies.

Federal Policy Changes: Changes to Federal policy including subsidies or tariffs can have significant impacts on the timing, price and feasibility of new renewable energy projects. The elimination of federal subsidies, including production and investment tax credits, can reduce the availability of renewable projects that are eligible for such subsidies and increase project costs for those who are not. Additionally, the limited availability of projects that qualify for the subsidies can drive increased competition in the near-term as LSEs work to close on these projects before subsidies sunset, likely putting upward pressure on procurement costs for the off-takers of the projects.

Tariffs can also create barriers to developing renewable energy projects. Many renewable energy projects being developed in California remain heavily dependent on internationally sourced components and equipment. Evolving U.S. tariff policies and domestic manufacturing requirements can materially increase project costs, create bid-price uncertainty and delay financing and procurement decisions.

iv. Other energy storage not described above

This section includes PG&E procurement activities (including near-term actions), and potential barriers for energy storage resources in PG&E's Conforming Portfolios (see Tables 7 and 10), in this report. As discussed above, PG&E expects to continue procuring storage resources for MTR and IRP targets.

PG&E is actively implementing California's programs to develop cost effective energy storage resources in the state to integrate renewable resources, provide output in periods of peak demand, and reduce GHG emissions.

PG&E envisions a large and growing need for energy storage in the future as California continues to increase renewable energy production, pursue increasingly ambitious GHG reduction goals, and significant load growth through data center development. In summary, going forward there is ample opportunity for utilities, third-party storage providers, and retail customers to be part of the energy storage solution incorporating a wide array of storage technologies. Table 36 below provides a summary of PG&E's energy storage actions, barriers, and recommendations.

TABLE 36
ENERGY STORAGE – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS

Existing Near-Term Actions	• Mid-Term Reliability (MTR) RFOs. • Greenhouse Gas Free (GHG) RFOs.
Key Barriers	• Interconnection queue and study process delays. • Transmission availability and network upgrades. • Permitting/local siting approvals. • Tariff and trade policy uncertainty.
Proposed New Near-Term Actions/ CPUC Direction	None at this time.
Deviations From Current Resource Plans	No deviations.
Recommendation for Future IRPs	Continue modeling energy storage resources as candidate resources.

Existing Near-Term Actions

PG&E is currently procuring energy storage resources through its Mid-Term Reliability and GHG Free RFOs. Resources procured through those RFOs will be used to meet the Mid-Term Reliability and IRP Procurement Order (D.26-02-057) procurement requirements, as well as assisting PG&E in meeting its GHG emissions reduction targets.

Key Barriers

Interconnection queue and study process delays: Projects must obtain CAISO interconnection approval before they can connect to the grid. Historically, CAISO's queue became overwhelmed by thousands of speculative solar and storage projects, creating multi-year study and approval delays. Even with recent reforms implementing FERC Order 2023 principles, developers still face uncertainty about study timelines, network upgrade requirements, and ultimate queue advancement.

Transmission Constraints and Network Upgrade Requirements: Many storage projects are proposed in areas with strong grid needs or co-located renewable generation, but available transmission capacity is limited. Projects may be assigned costly network upgrades or become dependent on transmission projects that are years from completion. California agencies have repeatedly identified transmission expansion as a critical bottleneck to achieving clean energy targets.

Permitting and Local Siting Challenges: While storage projects generally permit faster than large thermal generation facilities, local governments, fire authorities, environmental reviews, and community opposition can still significantly delay projects. Battery fire concerns following several high-profile incidents have increased scrutiny of safety plans, emergency response protocols, and site design.

Tariff and Trade Policy Uncertainty: California storage projects remain heavily dependent on globally sourced battery equipment. Evolving U.S. tariff policies and domestic manufacturing requirements can materially increase project costs, create bid-price uncertainty, and delay financing and procurement decisions.

v. Other demand response not described above

Flexible load resources play an important role in fostering an affordable clean energy transition when they can be deployed in a manner that is reliable, secure, cost effective, and adaptable to changing grid conditions. Demand response supports these objectives by (a) helping manage peak demand, (b) enhancing system reliability and providing resource adequacy, (c) increasing the utilization of existing grid and system capacity, and (d) enabling electrification, load growth,

and integration of large new loads at least cost. Consistent with California's Energy Action Plan and the state's net-zero carbon goal by 2045, PG&E has developed a diverse set of demand response solutions intended to support grid reliability and customer affordability. PG&E's 2024-2027 DR programs comprise a portfolio of approximately 317 megawatts (MW) of programs and pilots, which include residential, commercial, industrial, and agricultural customers. These programs, approved by the Commission in D.23-12-005, are designed to provide either price-responsive (economic) or reliability-based (emergency) capacity. In addition to PG&E's existing DR programs, PG&E is continuing to evolve its portfolio, working on a range of pilots, programs, and initiatives that address changing grid needs and better utilize advanced technologies, and support third-party DR market participation. PG&E facilitates third-party provider participation that directly bids into the CAISO markets with access to customer-authorized data for CAISO registration, verification of customer eligibility, and settlement processes for such a mechanism.[125]

PG&E is in its current funding cycle for DR programs (2023-2027)[126] and submitted comments in the Enhanced Demand Response OIR[127] (EDROIR) in response to the Energy Division Staff Proposal for a two-year bridge period extending this portfolio through 2029. PG&E expects the EDROIR to shape the longer-term role of demand response and flexible load as California's grid, customer technologies, and policy objectives continue to evolve. As reflected in PG&E's recent filings, key issues before the Commission include how demand response should be valued and measured; how multiple grid needs should be met within the same program under a virtual power plant (VPP) structure; how program design should adapt to support accelerating electrification, growing the deployment of distributed energy resources (DERs), and streamlining customer enrollment; and how demand response should complement dynamic rates and other load management solutions. PG&E also expects the proceeding to address the standards needed to support cost-effective, reliable, and scalable DR over time. In this context, PG&E views demand response as an important flexible load tool that should continue to evolve alongside rate design, electrification, and DER adoption, while remaining grounded in

[125] This includes the PG&E Electric Rule 24 tariff.

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

[127] R.25-09-004.

operational experience and Commission guidance developed in the EDROIR and related proceedings.

vi. Other energy efficiency not described above

PG&E's Energy Efficiency (EE) Portfolio Plan covering the 2028–2031 period, and its corresponding 2028–2035 Strategic Business Plan, filed in March 2026, are designed to support California's transition to a decarbonized energy system while delivering strong Total System Benefit (TSB),[128] advancing customer affordability, maintaining disciplined stewardship of ratepayer funds, and aligning with the CPUC's long-term system goals.

PG&E administers EE portfolios that aim to support the transition to an affordable, decarbonized energy future while achieving TSB, energy savings, and peak demand reduction goals. In its Portfolio Plan, PG&E's operational excellence and continued portfolio reliability serve as the foundation for scaling building electrification (BE), enabling load flexibility, and supporting rate affordability. PG&E's Portfolio Plan intentionally blends proven, high performing EE programs with a targeted set of pilots and prospective initiatives focused on advancing BE and load flexibility, designed to address persistent market and system barriers.

PG&E's EE portfolio enters this period with a responsibility and an opportunity to do two things at once:

1) Continue to consistently deliver cost-effective EE; and
2) Lay the groundwork for scaled deployment of efficient, flexible electrification.

For BE to succeed at scale, electric equipment must be installed correctly, operate efficiently, and integrate smoothly with evolving grid needs. This means that electrification technologies should be efficient and controllable, and customers should feel confident that electrification will maintain or improve comfort, deliver bill savings over time, and fit into their lives. The

[128] In May 2021, the CPUC issued D.21-05-031, which put in place a new performance metric, Total System Benefit (TSB), for ratepayer funded EE portfolios in California beginning in 2024. TSB is defined as "the sum of the benefit that a measure provides to the electric and natural gas systems." TSB is an expression, in dollars, of the lifecycle energy, ancillary services, generation capacity, T&D capacity, and GHG benefits of energy efficiency activities, on an annual basis. The TSB metric replaces energy and peak demand savings as the goals metric for ratepayer funded EE programs. The shift to the TSB metric will recognize the impact of longer life EE measures over the full time they are installed and saving energy. It also assigns greater value to load reduction that occurs at times that align with system needs. The TSB metric is fuel agnostic and thus may more easily facilitate fuel substitution.

8-year business plan period presents a pivotal opportunity to prepare the market to support a strategic, customer-driven transition.

PG&E's EE Portfolio Plan uses its resource acquisition (RA) segment as a foundation to build toward this future. EE will continue to drive energy savings in the near term, while targeted market support activities expand the availability and effectiveness of efficient, flexible-ready BE technologies over time. As markets mature and customer readiness strengthens, both BE and load flexibility-enabled technologies are expected to account for a growing share of the portfolio. Future growth of BE measures is likely to occur in the RA segment as those measures demonstrate cost-effectiveness and scalability.

By the end of the eight-year strategic plan period, PG&E envisions its EE portfolio evolving into an integrated platform that better supports reliable, flexible, and affordable BE. By 2035, the market should have:

- Customers who understand and trust electrified building solutions;
- Strong availability of efficient, load flexibility-ready equipment across retail and distributor channels;
- A skilled installation workforce distributed across PG&E's service area; and
- A multi-distributed energy resource (DER) integrated EE portfolio capable of delivering savings and load flexibility, while supporting long-term reliability.

Table 37 below provides a summary of PG&E's energy efficiency actions, barriers, and recommendations.

TABLE 37
ENERGY EFFICIENCY – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS

Existing Near-Term Actions	• PG&E is expected to achieve its four-year (2024-2027) TSB goal and deliver a cost-effective RA segment • PG&E filed its 2028-2035 EE Strategic Business Plan Application on March 16, 2026, and expects a decision in Q2 2027.
Key Barriers	Common barriers that limit customer adoption of EE and BE across customer sectors include, but are not limited to: • High upfront costs; • Limited access to affordable credit; • Constrained product supply; lack of workforce trust or poor perception of EE/BE appliances; • A shortage of a trained electrification and decarbonization workforce relative to the demand expected to be created by new zero-emission appliance standards; and • Long term uncertainty for federal appliance standards and efficiency related tax credits.
Proposed New Near-Term Actions / Commission Direction	• Commission should approve PG&E's 2028-2035 EE Strategic Business Plan.
Deviations From Current Resource Plans	None at this time.
Recommendation for Future IRPs	None at this time.

vii. Other distributed generation not described above

Here, distributed generation (DG) refers to customer-sited renewable generation installations – primarily rooftop solar photovoltaic (PV) systems and, increasingly, rooftop solar PV systems paired with battery storage. These behind-the-meter (BTM) resources reduce and re-shape customer load profiles. PG&E recently reached 1,000,000 bundled and unbundled customer service agreements with DG installed behind the utility meter.

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 supporting the incorporation of DG into state-wide load planning and building codes.

DG growth is driven primarily by DG-specific tariffs. Following decisions issued in Rulemaking 20-08-020, those tariffs have transitioned from a net energy metering framework, in which DG energy exported to the grid was valued based on retail rates, to a net billing framework, in which exported DG energy is valued based on avoided cost benefits.

DG growth is driven to a lesser extent by targeted incentive programs that PG&E manages or supports. These include:

- The Self Generation Incentive Program (SGIP), administered by PG&E in its service area, and which currently provides solar and storage incentives to low-income residential customers and has historically provided incentives for various DG technologies to both commercial and residential customers.
- The Disadvantaged Communities Single-Family Affordable Solar Homes (DAC-SASH) program, administered by Grid Alternatives on behalf of all three IOUs, and which provides rooftop solar installations to low-income customers in DACs.
- The Solar on Multifamily Affordable Housing (SOMAH) program, administered by the Center for Sustainable Energy for California on behalf of all three IOUs, and which provides technical and monetary support for solar installations on multifamily buildings.

PG&E supports these programs through, among other things, providing necessary data to the program administrator (PA) when it is not the PA itself, reviewing final incentive packages, and processing payments. In addition, PG&E ensures the safe interconnection of the solar and/or storage facilities incentivized under these programs.

PG&E also administers two green rate programs—Solar Choice and Green Saver—in which customers can participate. These programs do not result in customer-sited rooftop solar installations; instead, PG&E procures wholesale, front-of-the meter renewable resources on behalf of participants and hence these resources are not included in the DG forecast. PG&E's Solar Choice program is available to all bundled service customers, and the Green Saver program is available to low-income bundled service customers in disadvantaged communities.[129]

viii. Transportation electrification, including any investments that correspond to different levels than what is included in Integrated Energy Policy Report (IEPR)

PG&E's Transportation Electrification Vision and Goals:

[129] Solar Choice is currently closed to new enrollment and Green Saver is enrolled to capacity.

PG&E aims to decarbonize the energy system while putting downward pressure on electric rates by advancing Transportation Electrification (TE). Effectively integrating new TE load into the grid can enhance reliability and resiliency while reducing greenhouse gas (GHG) emissions. To realize these benefits and support California's goal of five million electric vehicles (EVs) on the road by 2030, PG&E is advancing toward serving three million EVs in its service area—its share of the state target—while enabling approximately 550 MW of flexible EV load across light-, medium-, and heavy-duty vehicles by 2030.

To deliver on these outcomes and scale EV adoption effectively, PG&E is advancing a focused set of Transportation Electrification priorities:

PG&E's TE priorities:

- Accelerate charging infrastructure deployment to support EV adoption
- Reduce total cost of EV ownership for customers
- Simplify and streamline the EV customer experience
- Proactively plan and scale the grid for EV-driven load growth
- Activate EVs as grid assets through vehicle-grid integration (VGI)

Current TE offerings:

To meet these goals across its service territory, PG&E's current and planned offerings are designed to reduce key barriers to transportation electrification (TE). In the near term, PG&E continues to implement CPUC-approved infrastructure programs, rates, and pilots, while expanding targeted offerings to better serve all customers—including those in Disadvantaged Communities (DACs). Over time, PG&E will continue evolving its portfolio through new programs, rate design, and technology innovation.

Infrastructure Solutions: PG&E is enabling transportation electrification by supporting customers from early planning through infrastructure deployment and energization, with a focus on scaling medium- and heavy-duty (MHD) electrification and expanding access to charging.

- *EV Advisory Services (EVAS) Program*
  Provides no-cost one-on-one guidance to medium and heavy-duty (MHD) fleet customers. It offers fleet electrification support including education, planning studies, site and charger design, capacity analysis, utility application support, infrastructure installation coordination, and operational optimization. The program has served 515 sites to-date.[130]

[130] Data as of June 15, 2026.

- *EV Fleet Program*
  Provides funding and support to install charging infrastructure for medium- and heavy-duty vehicle fleets. Covers make-ready infrastructure and offers rebates for EV chargers. PG&E has a goal to construct 375 sites and to support 6,500 vehicles by 2028. PG&E has exceeded that goal with 439 contracts signed and 7,998 vehicles committed.[131]
- *EV Power Ready (Rule 29)*
  EV Power Ready (also referred to as Rule 29) is PG&E's pathway for energizing new, separate EV charging service for commercial customers, with PG&E covering the utility-side installation costs. PG&E is seeing growth in EV Power Ready demand, underscoring its importance as a scalable tool to support the state's electrification transition. EV Power Ready can support the anticipated increase in EV charging interconnection by reducing the cost and complexity for customers to install EV charging infrastructure.[132]
- *EV Charge Parks Program*
  Installs EV charging infrastructure at state parks and beaches. The program covers costs of To-The-Meter (TTM), which is utility side infrastructure installation and Behind-The-Meter (BTM), which is customer side infrastructure installation. PG&E targets constructing 6 sites with 43 ports and anticipates constructing the first site in 2026.
- *Multi-Family Housing and Small Business Direct Install Pilot*
  This is a direct installation program where PG&E installs Level 1 and Level 2 EV chargers at multifamily housing (MFH) units, not-for-profit organizations and small businesses, at no cost for sites located in a priority community. The program targets to install 2000 ports at approximately 450 sites.

PG&E has successfully implemented prior infrastructure programs that expanded charging access and continue to inform current program design:

- *EV Charge Schools Program*
  Deployed EV charging infrastructure at schools to support student, staff, and community access to charging. The program is completed, with the installation of 15 sites and 96 ports completed in 2026.
- *EV Fast Charge Program*
  Delivered public direct current fast charging (DCFC) infrastructure to support corridor and

[131] Data as of June 11, 2026

[132] PG&E Electric Rule 29, <https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_29.pdf> (accessed August 3, 2026).

community charging availability. This program installed 39 sites, 190 ports and completed in 2026.

Residential Customer Programs: PG&E is expanding access to EV adoption for residential customers—particularly income-qualified customers and those without access to dedicated charging—through targeted incentives and solutions that lower upfront costs and address charging barriers.

- *Pre-Owned EV Rebate*: Offers rebates to help customers purchase pre-owned electric vehicles, with additional support for income-qualified customers.
- *Residential Charging Solutions*: Supports home charging through rebates, education, and installation solutions designed to minimize panel upgrade needs. The program includes additional support for panel upgrades, circuit extensions, and contractor enablement.
- *Affordable Public Charging*: Provides charging support for income-qualified customers who do not have access to home charging, via a prepaid debit card that can be used at physical payment terminals and through network applications. This program launches in Q3 2026.

Customer Affordability and Tools: PG&E supports EV adoption through rates and tools that help customers better understand costs, identify savings opportunities, and make informed vehicle and charging decisions.

- *EV Specific Rates:* PG&E offers residential and business EV rate plans that use time-of-use (TOU) pricing to lower charging costs when energy demand is low, helping customers save by shifting charging to off-peak hours. Residential EV rates EV2-A and EV-B either bundle home and EV usage on a single meter (EV2-A) or separate EV charging onto a dedicated second meter with its own TOU pricing (EV-B). For businesses, rates also include subscription-based plans (BEV1 and BEV2) that combine a customizable monthly subscription charge with a TOU rate to help lower costs.
- *EV Savings and Fleet Calculators:* PG&E provides the EV Savings and Fleet calculators, with comprehensive vehicle catalogues, rate calculators, total cost of ownership calculations, and personalized incentive and rebate information. This guidance empowers customers and fleet operators to make the decision to transition to an EV easier.
- *Resilient Fleets Charging Playbook:* Guides critical fleet customers (e.g., transit, emergency response, school buses) in designing reliable charging as they electrify. Highlights solutions such as behind-the-meter storage to ensure continuity of service and reduce operational risk.

Vehicle-Grid Integration (VGI) Pilots: Through VGI pilots, PG&E is unlocking EVs as a flexible grid resource by enabling smarter charging, bidirectional capability, and load management that supports customer affordability.

- *V2X Residential Pilot:* This pilot tests how residential EVs at homes can provide backup power, reduce customer bills, and support grid services. It is designed to show how residential EVs can become flexible energy assets that improve resilience for customers while creating value for the broader electric system.
- *V2X Commercial Pilot:* This pilot explores how commercial EVs can deliver backup power, lower building energy costs, and provide grid support. It helps demonstrate how fleet electrification can serve as a flexible and scalable grid resource for businesses.
- *V2X Microgrid Pilot:* This, which is now closed, pilot evaluated how EVs can charge and discharge within microgrids to support resiliency during outages. It showed how vehicles can play a meaningful role in community and critical infrastructure resilience, especially in outage-prone areas.

Supporting EV Growth with Grid Planning and Infrastructure: These solutions focus on improving grid readiness—accelerating customer interconnections while proactively building distribution capacity to support future EV load, particularly for medium- and heavy-duty (MDHD) fleets.

- *Flex Connect:* PG&E's flexible service connection approach helps customers come online sooner in areas with constrained capacity. By using automated load management tied to day-ahead circuit conditions, PG&E can dynamically manage charging load during constrained periods while enabling customers to begin service. This provides a near-term bridge that supports grid reliability and load growth ahead of permanent infrastructure upgrades.
- *Proactive Grid Planning:* PG&E is working to implement a proactive grid planning framework that incorporates forward-looking customer plans to better inform when and where load will materialize on the distribution system. PG&E is engaging with customers to better understand their EV charging plans and how best to incorporate them into PG&E's grid forecasting and planning efforts.
- *Capacity Pilot:* Developed as an alternative funding mechanism to address upstream distribution system constraints that can delay electrification—especially in disadvantaged communities (DACs)—the Capacity Pilot funds grid upgrades required to serve current interconnection requests. By supporting necessary feeder and substation improvements for MDHD charging applications, the pilot helps reduce delays, enable larger fleet

deployments, and ensure the grid can reliably accommodate growing EV demand in priority areas while reducing costs to ratepayers.

Key Barriers

While California has made meaningful progress on EV adoption, key barriers persist that constrain market growth, delay electrification, and limit equitable access.

- *Lack of availability of charging infrastructure*: Access to charging infrastructure remains a significant barrier to EV adoption across vehicle types. The AB 2127 EV Charging Infrastructure Assessment[133] projects that 1.01M public and shared private charging ports will be needed to support 7.1M light duty EVs in California by 2030. California currently has 216,445 public and private charging ports,[134] leaving a substantial gap relative to the projected need.
- *Total cost of ownership:* Although EV technology is improving and model availability is expanding, EVs can still carry higher costs than traditional internal combustion engine vehicles. This is especially the case for medium- and heavy-duty vehicles, where EV options remain more limited and prices are considerably higher. In addition, new EV loads may necessitate TTM and/or BTM infrastructure upgrades that increase costs and extend timelines to vehicle electrification.
- *Lack of EV awareness or understanding:* The decision to purchase an EV or transition a fleet requires an understanding of technologies and considerations extending beyond the vehicle itself, including charging equipment, applicable rate structures, strategies to optimize TOU benefits, and the range of incentive programs available to residential and commercial customers.
- *Inequitable access to EVs and EV charging:* Barriers to transportation electrification—particularly limited charging availability and higher upfront vehicle costs—are often more pronounced for hard-to-reach and underserved customers and communities. These challenges are further compounded by the relative scarcity of charging infrastructure in disadvantaged communities and in areas serving customers who live in multi-family or single-family rental housing without access to at-home charging.

[133] https://www.energy.ca.gov/data-reports/reports/electric-vehicle-charging-infrastructure-assessment-ab-2127 (accessed August 3, 2026)

[134] https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection/electric (accessed August 3, 2026)

Proposed New Near-Term Actions/Commission Direction

- PG&E is not requesting any additional actions in this section of the IRP.

Deviations from Current Resource Plans

- None.

Recommendations for Future IRPs

- PG&E recommends that the IRP should evaluate EVs as a candidate resource by including assumptions for Vehicle-Grid Integration (VGI) across major vehicle categories. The IRP should include assumptions for light-duty vehicles as well as for medium- and heavy-duty vehicles such as school buses and transit fleets that have load shifting and V2G potential.

ix. Building electrification, including any investments that correspond to different levels than what is included in Integrated Energy Policy Report (IEPR)

In June 2022, PG&E issued its *Climate Strategy Report*, which established a goal to achieve a net zero energy system in 2040, five years ahead of the California carbon neutrality goal established in Executive Order B-55-18. PG&E recognizes that building decarbonization will play a central role in achieving these goals and that the utility can support this transition through electrification, load flexibility, and a managed evolution of the gas system, with implications for net load shape and resource needs.

Building Electrification (BE) increases electric demand while also expanding opportunities to shape load profiles through flexible end uses, including heat pumps, water heating, and thermal storage. PG&E is advancing a strategy that pairs electrification with load flexibility to shift consumption to lower-cost, lower-emissions hours and mitigate peak demand impacts. The strategy also supports strategic load growth in underutilized areas of the grid to improve overall system utilization, better align demand with grid conditions, and distribute fixed system costs across a greater number of kilowatt-hours. PG&E's vision is a future where BE is fast, easy, affordable, and accessible to all customers while supporting safe, reliable, and cost-effective energy service. PG&E's strategy is also focused on advancing the market conditions necessary to enable customers to electrify affordably and seamlessly. This includes targeted pilots, customer programs, rate designs, workforce development, and planning tools intended to test, refine, and scale successful approaches. PG&E is also expanding from customer-level electrification efforts toward more integrated gas and electric system planning, including evaluation of targeted and zonal electrification opportunities as part of a broader neighborhood decarbonization strategy.

On March 16, 2026, PG&E filed its 2028-2035 Energy Efficiency Strategic Business Plan that outlines PG&E's strategy to enable BE-driven load flexibility that shapes hourly demand, reduces system peaks, and improves alignment with renewable generation profiles, thereby supporting IRP portfolio optimization and resource adequacy outcomes. PG&E plans to implement three tactics as part of this strategy: (a) deploy efficient electric equipment capable of load flexibility; (b) integrate EE and BE with other load flexibility programs; and (c) support development of load flexibility standards.

Table 38 below provides a summary of PG&E's actions to support building electrification load growth, key barriers to building electrification, and recommendations.

TABLE 38
BUILDING ELECTRIFICATION – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS

Existing Near-Term Actions	**Supporting BE Economics** • **Direct incentives:** PG&E offers various incentives to reduce the cost of efficient electric appliances, especially for equity customers • **Load shifting program:** PG&E's WatterSaver program provides customers incentives to shift water heating load to lower-demand and lower-cost periods**.** • **Solutions to reduce upgrade costs:** PG&E is testing solutions to help customers defer or avoid costly electrical upgrades. For instance, PG&E is partnering with SPAN to deploy smart panels and AMI 2.0 meters to enable dynamic load management of existing electric loads in a home. • **Increasing access to capital:** PG&E is expanding on-bill financing for building electrification for non-residential customers • **Electric rates:** PG&E offers an E-ELEC electrification rate with a lower per-kWh rate for customers that electrify their home and offers tools for customers to assess which rate option is best for their household and evaluate the potential bill impacts of electrification. • **New construction:** PG&E supports the adoption and implementation of state and local codes and policies that advance cost-effective electrification in new construction. **Improving the customer experience** • **Customer education:** PG&E supports customer adoption of building electrification through integrated digital tools, targeted outreach, and customer journey–based engagement. **Workforce training:** Through its Workforce Education and Training (WE&T) program, PG&E provides no-cost electrification training to its customers and to the building industry. **Installation process improvements:** PG&E's PanelBoost pilot noted above can help accelerate the installation process of electric appliances by helping customers defer or avoid panel and service upsizing **Integrating gas and electric planning** • **Integrated tools:** PG&E has created a *Geospatial Electrification Tool (formerly Gas Asset Analysis Tool)*, which identifies portions of the gas system which may make sense to further investigate as candidates for zonal and/or targeted electrification. The data is currently in beta testing with community users to validate the effectiveness of the methodology. • **Zonal electrification:** PG&E is implementing several zonal electrification pilots and programs to advance cost-effective electrification and gas decommissioning.

TABLE 38
BUILDING ELECTRIFICATION – SUMMARY OF PG&E ACTIONS AND RECOMMENDATIONS (CONTINUED)

Key Barriers	**Limited availability of external and non-ratepayer funding:** scaling electrification to meet state goals will require significant funding solutions beyond traditional ratepayer source **Affordability and customer cost impacts:** upfront costs, such as appliances, a primary barrier, alongside potential rate impacts from supporting infrastructure. Addressing both customer-level and system-level cost impacts will be important to ensure equitable and scalable adoption. **Insufficient funding for remediation and enabling upgrades:** many buildings require enabling upgrades (e.g., panel replacements, wiring, health and safety improvements) prior to electrification, but remediation funding is limited. **Fragmented statewide funding and coordination framework:** funding is distributed across multiple programs with differing rules and priorities and should be better coordinated to deliver optimal outcomes and reduce duplication. **Customer experience complexity and implementation barriers:** customer adoption can be constrained by complex application processes, contractor availability, project timelines, and uncertainty regarding costs and performance.
Proposed New Near-Term Actions/ Commission Direction	PG&E is not requesting any additional actions in this IRP.
Deviations from current resource plans	None.
Recommendations for Future IRPs	None.

x. Potential Centralized Procurement, pursuant to AB-1373

While there have been some delays in centralized procurement pursuant to AB 1373, PG&E considers the impact that these volumes would have in this filing. Generally, any incremental resources procured by or on behalf of PG&E may cover some of its open position and reduce its overall procurement need. As noted in the Study Design section of this filing, PG&E modeled Scenario E as a modified conforming bundled portfolio supply mix including AB 1373 procurement assumptions provided by the Commission.

Scenario A satisfies PG&E's conforming portfolio requirements as outlined in the 2026 IRP Filing Requirements[135] while Scenario E presents the modified conforming bundled portfolio supply mix based on the AB 1373 procurement assumptions provided by the Commission for PG&E. Comparing the study results in Tables 10 and 14 for Scenarios A and E, there is no difference in forecasted resource additions for the first two planning years (2028, 2030) since no DWR procurement is anticipated until after 2030. By 2035, Scenario E needs almost 1,000 MW less of resources additions with AB 1373 volumes included. This difference grows to roughly 2,500 MW and 3,500 MW for 2040 and 2045 respectively as more volumes come online. Should these volumes materialize, PG&E may need to procure fewer resources on its own to meet its overall IRP portfolio needs.

xi. Other

PG&E has not identified any other resources not covered in the above sections.

b. Disadvantaged Communities (DACs)

PG&E appreciates the Commission's focus on Disadvantaged Communities (DACs) in this Integrated Resource Plan (IRP), particularly considering the historically high levels of air pollutants recorded in DACs by the California Environmental Protection Agency (CalEPA). These communities often face significant economic challenges and a relatively high energy burden compared to other areas within PG&E's service territory. Moreover, CalEPA has identified these communities as having the highest percentile of adverse scores related to poor environmental health and air quality. Although the issues confronting DACs are broader than the scope of the CPUC's IRP proceeding, the IRP process provides a valuable platform for considering how electric sector resource planning and associated decarbonization efforts, such as clean transportation and building electrification, may impact air pollution and DACs.

i. Transportation Electrification

Transportation electrification is a critical component of California's efforts to mitigate the effects of climate change and address the adverse human health effects associated with emissions from the transportation system. This is especially true in disadvantaged communities (DACs), which are often situated near heavily traveled freight corridors, where air pollutant concentrations often exceed health-based standards. Zero-emission vehicles (ZEVs) are significantly more energy efficient than diesel vehicles, reduce dependence on petroleum, and

[135] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/updated-filing-requirements-overview-document.pdf (accessed August 3, 2026)

substantially lower greenhouse gas emissions and criteria air pollutants that adversely affect human health.

In recognition of this, California has set specific and ambitious transportation electrification goals through key legislation and executive orders which have been instrumental in addressing GHG emissions from the transportation sector. This is true for light duty EVs, as well as non-residential fleet and medium and heavy-duty vehicles. To enable this, the Clean Energy and Pollution Reduction Act of 2015 (SB 350) and the Electric Vehicle Charging Infrastructure bills (AB 1082 and AB 1083) laid the groundwork for expanding electric vehicle (EV) infrastructure across the state. As part of these efforts, the California Legislature in Public Utilities Code Section 740.12 accurately asserted that "[a]dvanced clean vehicles and fuels are needed to reduce petroleum use, to meet air quality standards, to improve public health, and to achieve greenhouse gas emission reduction goals," and that widespread transportation electrification "requires electrical corporations to increase access to the use of electricity as a transportation fuel."[136]

This legislation is complemented by a portfolio of regulations, including the California Air Resource Board (CARB) Advanced Clean Trucks,[137] Advanced Clean Fleets,[138] Clean Miles Standard,[139] and Advanced Clean Cars II[140] regulations that all have an emphasis on equity and reducing emissions in DACs. These regulations individually and together are effectively and deliberately moving the state towards the ambitious goals established in Executive Order N-79-20, including that by 2035 all sales of passenger cars and trucks be zero-emissions, and that by 2045 all medium- and heavy-duty vehicles be zero emissions for all operations where feasible, also directing an earlier timeline of 2035 for drayage trucks.

The state still has significant work ahead in order to meet its goals, in particular with the build-out of the necessary enabling charging infrastructure over the next several years. The

[136] Cal. Pub. Util. Code § 740.12(a)(1)(A), (E).

[137] See CARB, Advanced Clean Trucks, available at: https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks (accessed August 3, 2026).

[138] See CARB, Advanced Clean Fleets, available at: https://ww2.arb.ca.gov/our-work/programs/advanced-clean-fleets (accessed August 3, 2026).

[139] See CARB, Clean Miles Standard Regulation, available at: https://ww2.arb.ca.gov/rulemaking/2021/cleanmilesstandard (accessed August 3, 2026).

[140] See CARB, Advanced Clean Cars II, available at: https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program/advanced-clean-cars-ii (accessed August 3, 2026).

March 2024 Electric Vehicle Charging Infrastructure Assessment per AB 2127 finds that California installed approximately 83,000 public and shared Level 2 chargers and 10,000 DC fast chargers, through 2023.[141] The same report anticipates that by 2030, over 1 million chargers, including 83,000 DC fast chargers will be needed to support the state's light duty EV fleet. Additionally, by 2030, the state's medium- and heavy-duty EV fleet will need about 114,500 chargers, including 109,000 lower-powered (20-150 kW) depot chargers and 5,500 higher-powered (350-1,500 kW) en-route chargers. Without adequate and timely availability of necessary enabling grid capacity, much of this will not be possible, and realization of these goals will be significantly challenged.

For PG&E's part, and in alignment with these policy drivers and the state's recognition of the critical role utilities play in advancing equitable access to transportation electrification to help accelerate health benefits and equitable outcomes in DACs, PG&E has a robust portfolio of programs and customer offerings tailored to help realize and accelerate these benefits, as detailed further below in Table 39.

[141] See California Energy Commission, AB 2127 Second Electric Vehicle Charging Infrastructure Assessment: Assessing Charging Needs to Support Zero-Emission Vehicles in 2030 and 2035, available at: <https://www.energy.ca.gov/publications/2024/assembly-bill-2127-second-electric-vehicle-charging-infrastructure-assessment> (accessed August 3, 2026).

TABLE 39
COMMERCIAL AND RESIDENTIAL ELECTRIC VEHICLE TRANSPORTATION PROGRAMS

Program	Description	Application Status	Budget	Years
V2X Residential	Incentivizes up to 1,000 residential customers to pair bidirectional EV chargers with lightweight electric vehicles and participate in V2B backup power and/or V2G export to grid V2X. Incentives can help with bidirectional EV charger costs and participants can earn credit towards their bills.	Open	$7.5M	2023-2026
V2X Commercial	Incentivizes up to 200 commercial customers with V2X medium and heavy-duty EVs to participate in V2B backup power and to provide V2G export to grid. Participants receive upfront incentives designed to help cover the cost of bidirectional EV chargers along with earning credit towards their bills.	Open	$2.7M	2023-2026
V2X Micro Grid	Demonstration pilot for demonstration and development of production-ready technology which leverages BTM DERs (bi-directional EV's) for resiliency and GHG reduction in a multi-customer (PSPS/Community microgrid) or single-customer microgrid supporting critical infrastructure.	Closed	$1.5M	2023-2025
EV Charge Manager	Utilizes third-party software to align the lowest EV charging times for residential customers while also alleviating constraints on the grid and extending the lifetime of distribution assets. The pilot was extended through 2026 to test DERMs integration and how an OEM-bundled incentive can help drive EV adoption.	Open	$5.8M	2024-2026

TABLE 39
COMMERCIAL AND RESIDENTIAL ELECTRIC VEHICLE TRANSPORTATION PROGRAMS (CONTINUED)

Program	Description	Application Status	Budget	Years
EV Parks	Supports the installation of charging infrastructure for public charging at California State Parks	Closed	$5M	2023-2027
EV Fleet	Provides make-ready infrastructure and behind the meter incentives for Medium and Heavy-Duty fleets	Open	$236M	2019-2026
EV Advisory Services	Provides MDHD fleets comprehensive advisory support before, during, and after EV charger installation	Open	$18M	2025-2026
EV Advisory Services Phase 2	Provides nonresidential customers with comprehensive advisory support before, during, and after EV charger installation	Not yet open	$15M	2026-2029
Pre-owned EV Rebate	Provide a post-purchase rebate for pre-owned EVs, with a $1000 base rebate and additional $3000 for income-qualified customers	Open	$86.6M	2022-2026
Multifamily Housing & Small Business EV Charger Program	Install low-power chargers (Level 1 and Level 2) at small MUDs and small businesses that have excess capacity on panel	Closed	$25.2M	2022-2027
Residential Charging Solutions	Educational resources and financial support to install EV charging at homes	Closed	$7.3M	2022-2026
Residential Charging Solutions Expansion	Expansion to existing program offering upfront cost reductions through contractors or after-the-fact rebates for panel upgrades and circuit extensions, and customer/contractor education promoting panel optimization	Open	$19.3M	2024-2027
Affordable Public Charging	Provide a weekly public EV charging credit to income-qualified customers via a prepaid debit card that can be used at physical payment terminals and through network apps	Not yet open	$28.8M	2024-2028
Resilient Fleets	Provide an online playbook on resilient charging solutions, targeted at critical customers looking to electrify their fleets	Not yet open	$2.5M	2024-2028

TABLE 39
COMMERCIAL AND RESIDENTIAL ELECTRIC VEHICLE TRANSPORTATION PROGRAMS (CONTINUED)

Program	Description	Application Status	Budget	Years
Capacity Pilot	Fund grid capacity upgrades related to electric vehicle charging in equity communities	N/A	$20.0M	2024-2026

ii. DACs in PG&E's Service Area

PG&E provides electric service to 526 census tracts that are classified as a DAC using the guiding definition for this IRP. This corresponds to 0.8 million residential customer accounts, and 0.2 million business customer accounts, and approximately 126 residential customer accounts located on tribal lands and within a DAC. A full breakdown of PG&E's customers in DACs in comparison to the entire services territory is included in Tables 40 through 42 below.

Approximately 17 percent of PG&E's 5 million residential electric service territory customers live in DAC census tracts. The Central Valley represents a high concentration of customers located in DACs within PG&E's service territory for both residential and business accounts, with 53 percent and 59 percent of customers, respectively.

TABLE 40
OVERALL PG&E AND DISADVANTAGED COMMUNITIES POPULATION IN PG&E ELECTRIC SERVICE TERRITORY

Line No.	Customer Types	Overall PG&E	Disadvantaged Communities	Percent of Overall PG&E
1	Residential Customers	5,010,057	850,716	17%
2	Business Customers	661,015	162,386	25%

TABLE 41
REGIONAL DISTRIBUTION OF RESIDENTIAL CUSTOMER ACCOUNTS IN PG&E ELECTRIC TERRITORY

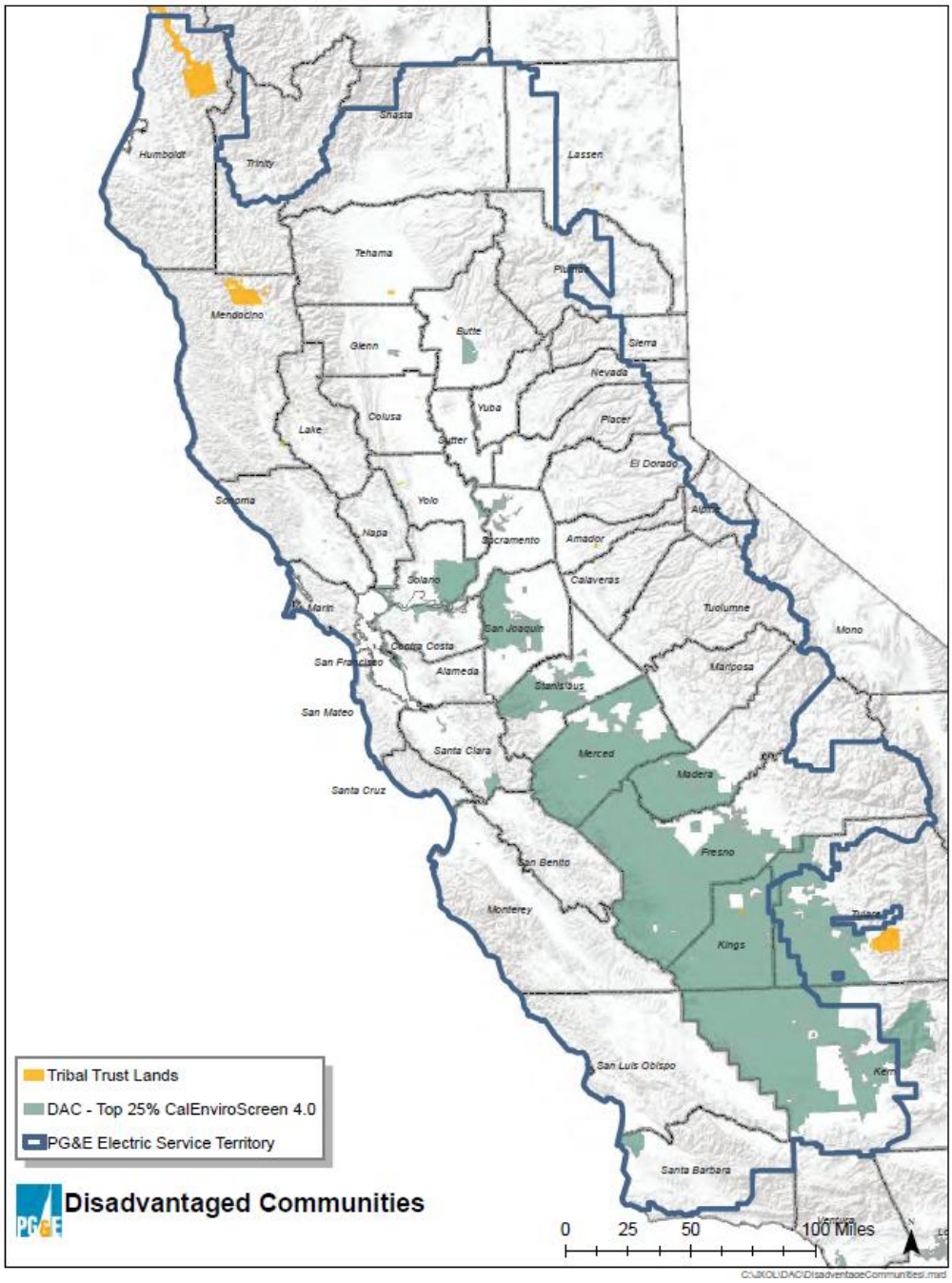
Line No.	PG&E Region	PG&E Electric Service Territory Customer Accounts (%)	PG&E Electric Service Territory Residential DAC Accounts (%)
1	Bay Area Region	1,682,533 (34%)	186,217 (22%)
2	Central Valley Region	1,083,998 (22%)	569,247 (67%)
3	North Coast Region	654,762 (13%)	25,558 (3%)
4	North Valley & Sierra Region	541,164 (11%)	29,547 (3%)
5	South Bay & Central Coast Region	1,047,600 (21%)	40,147 (5%)

TABLE 42
REGIONAL DISTRIBUTION OF BISOMESS CUSTOMER ACCOUNTS IN PG&E ELECTRIC TERRITORY

Line No.	PG&E Region	PG&E Business Accounts (%)	DAC Business Accounts (%)
1	Bay Area Region	160,788 (24%)	30,413 (19%)
2	Central Valley Region	188,217 (28%)	110,452 (68%)
3	North Coast Region	92,023 (14%)	4,311 (3%)
4	North Valley & Sierra Region	89,618 (14%)	6,268 (4%)
5	South Bay & Central Coast Region	130,369 (20%)	10,942 (7%)

As illustrated in Figure 14 below, PG&E displays the DACs and tribal lands in its service territory that correspond to the definition used in this IRP:

FIGURE 14
MAP OF DISADVANTAGED COMMUNITIES AND TRIBAL LANDS IN PG&E'S SERVICE TERRITORY



iii. Current and Planned Programs and Activities Impacting DACs

The information below offers a summary of existing and future PG&E programs and activities that affect DACs or support economic development within DACs.

A. Customer Programs

PG&E offers a variety of energy products, programs, and services to assist customers with bill affordability, building electrification, electric vehicles, and renewable energy adoption. These programs may be available to all customers within PG&E's service territory. However, some programs may involve increased marketing and outreach efforts to disadvantaged communities (DACs), provide greater financial benefits to DAC or low-income customers compared to other customers, or restrict program benefits to DACs and specific geographic areas.

Table 43 provides information on residential tariffs that are available to support bill affordability. Some of the programs, such as CARE and FERA, are limited to certain customers based on household income eligibility, while others have non-income specific eligibility criteria.

TABLE 43
RESIDENTIAL TARIFFS AND FINANCIAL ASSISTANCE PROGRAMS

Program	Details
California Alternative Rates for Energy (CARE)	• Discount on electricity and gas • Available for customers with an income at or below 200% Federal Poverty Guidelines
Family Electric Rate Assistance (FERA)	• Discount on electricity only • Available for customers with an income at or below 250% Federal Poverty Guidelines
Arrearage Management Plan (AMP)	• Debt forgiveness plan for customers enrolled in CARE or FERA
Relief for Energy Assistance through Community Help (REACH)	• Provides energy credits for low income customers facing disconnections due to hardship • Available for customers with an income at or below 200% Federal Poverty Guidelines
Budget Billing	• Calculates monthly payments based on average customer bills over the last 12 months to avoid seasonal spikes in bills • Available to all residential customers not on NEM and certain small business customers
Match My Payment	• Bill assistance to eligible customers • Household income must not exceed 400% Federal Poverty Guidelines • Matches every dollar paid by the customer up to $1,000 toward past due balance
Medical Baseline	• Provides an additional allotment of energy every month at the lowest price available on their rate • Sends more alerts before a Public Safety Power Shutoff • Available for customers with certain medical conditions
DAC-Green Tariff aka Green Saver	• Provides a 20% bill discount and 100% renewable energy to customers in a DAC who meet the income eligibility requirements for the CARE and FERA programs.

Table 44 lists programs offered by PG&E for residential energy management and electrification programs.

TABLE 44
RESIDENTIAL ENERGY MANAGEMENT AND ELECTRIFICATION PROGRAMS

Program	Details
Energy Savings Assistance (ESA)	• Provides income-qualified customers no-cost energy-efficiency and home improvement measures that can help reduce their energy bills and improve health, safety, and comfort. • Available for customers with an income at or below 250% Federal Poverty Guidelines
WatterSaver	• Daily thermal storage load shifting program that provides enrollment and participation incentives to customers with electric water heaters. • Provides incentives only for the control of electric water heaters, not for the equipment cost/installation. • Shifts electricity usage outside of peak period to utilize excess daytime renewable energy, lower customer bills, and reduce GHG emissions. • All electric PG&E customers who have an eligible water heater are eligible to participate – WatterSaver will provide any necessary controls, if needed, at no cost to the customer.

There are several building electrification pilots within PG&E's program portfolio that are either in progress or planned, as shown in Table 45. These programs have targeted customer populations, based either on income or geographic location, and aim to test and learn key strategies for scaling BE within DACs.

TABLE 45
RESIDENTIAL BUILDING ELECTRIFICATION PILOT PROGRAMS

Program	Details
ESA Pilot Plus/Pilot Deep	• Provides deeper energy savings and building electrification measures • Available for customers with an income at or below 250% Federal Poverty Guidelines
Electrify My Block	• Provides energy upgrades and electric appliances at no cost if customers live in an eligible 'zone' • Targets 'zones' that would allow PG&E to avoid costs associated with maintaining gas assets • Available to residents and businesses in disadvantaged and low-income neighborhoods in Contra Costa County
Powerful Neighborhoods	• Provides energy upgrades and electric appliances at no cost if customers live in an eligible zone Targets zones that would allow PG&E to avoid costs associated with maintaining gas assets • Available to single family, small multi-family, and businesses in disadvantaged and low-income neighborhoods in San Jose
EmPower My Home	• Accelerates full and partial building electrification for disadvantaged communities, as well as low income and hard to reach residential customers. • Covers 100% of project costs for customers at or below the 250% Federal Poverty Guidelines • Initially will target San Francisco, Oakland, and Fresno.

As mentioned earlier in this section, PG&E offers a wide selection of EV and EV infrastructure programs that support EV adoption. Program offerings are further detailed in Table 46 and Table 47.

TABLE 46
RESIDENTIAL TRANSPORTATION ELECTRIFICATION PROGRAMS

Program	Details
Multi-Family Home and Small Business Direct Install Pilot	• Installs low-power charges (Level 1 and Level 2) at multi-family and small businesses within equity communities
V2X Residential	• Offers a $2,500 upfront ($3,000 for customers in Disadvantaged Communities) • Additional $1,500 Early Adopter Incentive for the first 250 customers to enroll
Pre-Owned EV Rebate (POEV)	• Offers a post-purchase rebate for pre-owned EVs. • Base rebate is $1,000, but if the customer is income qualified, they get an additional $3,000.
Residential Charging Solutions Expansion	• Rebranded as Residential EV Charging rebate program • Offers 50% rebate on eligible EV Supply Equipment after installation. • Income-qualified customers are connected with PG&E Trade Ally Network contractors and may receive up to $5,000 for panel upgrades and EV charger installation.
Affordable Public Charging	• Offers a reloadable debit card incentive for income-qualified customers to use at public charging stations: $100 upfront, followed by $50 per week

TABLE 47
NONRESIDENTIAL TRANSPORTATION ELECTRIFICATION PROGRAMS

Program	Details
EV Fleet	• Funds and builds infrastructure from the electric grid to charging equipment at an estimated 700 fleet customers sites. • Partners with school districts, transit agencies, delivery fleets, and other business customers • 25% of the program budget will go towards investments in DACs • Also offers a rebate on EVSE cost to DACs up to a program total of $10 million
EV Advisory Services	• Provides education and consulting services for nonresidential EV projects • 50% of the program budget must serve sites that are located in AB841 Underserved Communities
V2X Commercial	For 3-phase bidirectional charger less than 50 kW: • Up to $2,500 upfront ($3,000 for customers in Disadvantaged Communities) For 3-phase bidirectional charger greater than or equal to 50 kW: • Up to $4,500 upfront ($5,000 for customers in Disadvantaged Communities)

Lastly, PG&E offers several renewable energy programs that specifically target DACs, as shown in Table 48. These programs provide incentives for solar PV adoption, supporting bill affordability as well as air quality improvements by reducing reliance on gas systems.

TABLE 48
RENEWABLE ENERGY PROGRAMS

Program	Details
Self Generation Incentive Program (SGIP)	• Provides rebates to qualified residential and business customers for battery storage systems • Incentives offered though the Equity Resiliency Budget prioritize projects in disadvantaged or low income communities and in High Fire Threat Districts where PSPS have impacted customers • Incentives are available for qualified low-income customers to install paired solar and storage through the Residential Solar and Storage Equity budget. • Customers that installed solar through the DAC-SASH program automatically qualify as low-income for storage-only incentives.
DAC – Single Family Affordable Solar Homes (DAC-SASH)	• Provides incentives to increase the adoption of solar PV by residential customers living in disadvantaged communities
SOMAH – Solar on Multifamily Affordable Housing	• Provides incentives to install solar and storage on multifamily affordable homes in DACs

B. Economic Development

PG&E is committed to building a supply chain that reflects the communities it serves and strengthens California's economic vitality. PG&E's partnerships with small, local, and diverse businesses support more than 28,000 jobs, generate $2.3 billion in income, and contribute $840 million in taxes to its communities. A diverse supplier base also makes PG&E stronger: it expands competition, increases innovation, improves local responsiveness, and enhances operational resilience by ensuring PG&E has a broad network of capable partners across California. PG&E is focused on expanding its supplier pipeline to attract and develop new hometown businesses that will help drive California's clean-energy transition.

C. Ongoing Community Outreach

PG&E engages with community-based organizations (CBOs) through multiple efforts throughout the year to increase awareness of program offerings, bill assistance, and provide a channel of open communication with disadvantaged and hard-to-reach communities. PG&E's outreach activities are described below. PG&E targets vulnerable communities by leveraging customer insights, including program enrollment and eligibility data, to drive more effective

outreach and engagement. PG&E integrated live customer service representatives at community events to encourage enrollment into assistance programs, while supporting individual billing and energy related needs.

1. CBO Education & Outreach Program

PG&E engages with community-based organizations (CBOs) through multiple efforts throughout the year to increase awareness of program offerings, bill assistance, and provide a channel of open communication with disadvantaged and hard-to-reach communities. PG&E's outreach activities are described below.

PG&E works with CBOs through the CARE Capitation (COC) Program, which pays CBOs for new enrollments in the CARE or FERA programs. Currently, the program has approximately 36 participating organizations, including both non-profit and for-profit organizations. PG&E is continuing to expand its COC program in addition to other outreach efforts and has averaged approximately 45 new enrollments each month in 2026.

A new Affordable Housing Outreach Program with 10 CBOs was implemented and launched in January 2026 and is scheduled to end in June 2026. There are 10 CBOs enrolled in the pilot who will engage with vulnerable and underserved affordable housing communities and hard-to-reach areas where bills are high and resources are limited. The outreach program focuses on in-person workshops and education on the assistance programs including CARE/FERA, ESA, Medical Baseline, REACH, Match My Payment, and other financial assistance programs. CBOs participating in the Affordable Housing Outreach Pilot are asked to distribute a monthly email or newsletter highlighting financial assistance programs promoted in the outreach. In addition to email communication, CBOs are required to hold at least six workshops during the duration of the pilot, with at least one workshop to be held at a community or cultural center, and at least one workshop to be held at a faith-based organization. As of April 2026, the CBOs participating in the Affordable Housing Outreach Pilot reported holding 30 in-person workshops and reaching 460 people since the start of the Pilot.

In Q4 2024, per D.24-02-046 PG&E launched a Community-Based Organization Arrears Case Management Pilot Program (CBO Pilot). This decision approved the CBO Pilot to reduce residential energy service disconnections. Community Action Partnership of Kern County (CAPK) was selected to participate in this CBO Pilot through a competitive bid process. CAPK enrolled 2,460 customers into the program. CAPK provided case management to enrolled customers and supported customers with enrollment in CARE, FERA, Medical Baseline, and other financial assistance programs. CBO Pilot services ended in March 2026.

2. CBO Community Forums

PG&E is committed to providing opportunities and forums to learn from community-based organizations (CBOs) and understanding their perspectives and recommendations for PG&E's programs and services. In 2022, as part of PG&E's effort to expand and deepen its CBO partnerships and engage CBOs across the service territory to assist in reaching customers and providing households education and outreach, PG&E created a new Community Perspectives Advisory Council (C-PAC). The purpose of the C-PAC is to enhance the ability of CBOs to offer suggestions and input on a broad variety of PG&E programs, projects, and proposals. PG&E collaborates with C-PAC members on real-time issues and structures the topics of meetings to align with programs, proposals, or questions that are timely and current.

3. Resilient Together Advisory Groups

Through the Resilient Together Initiative, PG&E partnered with community members to understand how climate hazards are impacting the energy-related resilience needs of the disadvantaged vulnerable communities within PG&E's service territory. This feedback informed PG&E's 2024 Climate Adaptation and Vulnerability Assessment (CAVA) filing. The outreach included:

- Convening five regional advisory groups, composed of 60 community-based organizations in disadvantaged and vulnerable communities.
- Conducting over 40 research interviews with community leaders.
- Collecting over 6,000 survey responses about impacts of climate hazards and energy outages.
- Developing culturally relevant materials translated into 10 different languages.

Through this process, disadvantaged climate-vulnerable communities shared their perspectives and recommendations to help guide PG&E's ongoing engagements and opportunities to support community resilience during extreme heat, power outages, flooding and wildfire events. PG&E is currently carrying out its second round of this engagement to inform its 2027 CAVA.

4. CBO Transportation Electrification Outreach

PG&E holds Marketing, Education and Outreach (ME&O) contracts with several CBOs to promote its EV programs. Within each CBO's communities, they play a crucial role in educating and guiding equity customers through their transition to EV adoption.

- Pre-owned EV Rebates, Residential EV Charging Rebates and Affordable Public Charging Programs: PG&E holds contracts with Breathe California and Valley Clean Air Now.

- EV Fleet Advisory Services: PG&E holds contracts with Breathe California, Acterra: Action for a Healthy Planet, and Cool the Earth.

5. Access and Functional Needs Customers

PG&E has a robust outreach program to support its Access and Functional Needs ("AFN") customers.[142] Although AFN customers are not limited to DACs, DACs contain a disproportionate number of AFN customers. Customers with AFN typically require additional accommodation during large-scale, long-duration power interruptions, such as Public Safety Power Shutoffs (PSPS). PG&E works annually to identify, communicate, and develop support services for its AFN customers before, during, and after PSPS. PG&E also works with a number of statewide government and stakeholder partnerships, including the Joint IOU Statewide AFN Advisory Council, to develop and review its annual AFN Plan for PSPS Support. To review a more detailed overview of PG&E's AFN activities, please see the 2026 AFN Plan.[143]

As outlined in PG&E's 2026 AFN Plan, PG&E is committed to continually enhancing its support plan for customers with AFN. One priority for PG&E is to ensure that it is continually working to identify who its most vulnerable community members are and working to prepare these individuals for power interruptions. One way PG&E works towards accomplishing this is by conducting outreach marketing campaigns that allow customers to self-identify their vulnerabilities and enroll in PG&E's support programs like Medical Baseline (MBL) and Self-Identified Vulnerable. This year PG&E is also working on updated AFN outreach campaigns for its Senior community members, those in residential care facilities, and unique AFN awareness campaigns through social media influencers. PG&E is also continuing its work to explore additional accommodation and preparedness materials for individuals with cognitive and intellectual disabilities, including neurodiversity. Additionally, PG&E partners with over 500 CBOs who help amplify its messaging and work with the AFN community on a regular basis, and act as another trusted resource for its customers to self-identify and seek assistance in its programs and services.

[142] Access and Functional Needs as defined by the CPUC **Government Code 8593**: Individuals who have developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking, older adults, children, people living in institutional settings or those who ware low income, homeless, or transportation disadvantaged, including but not limited to those who are dependent on public transit or those who are pregnant.

[143] https://www.pge.com/assets/pge/docs/outages-and-safety/safety/psps-afn-report-013026.pdf

D. Corporate Philanthropy

PG&E is dedicated to serving people, the planet, and California's prosperity by building and maintaining charitable partnerships with non-profit organizations, local and Tribal governments, and other community groups across Northern and Central California. PG&E's programs support resiliency to the impacts of climate change, while also helping to ensure its customers and coworkers are safe and have opportunities to grow and thrive in their communities. PG&E's charitable programs are funded entirely by its shareholders and have no impact on its customers' energy rates. This support can come from PG&E or The PG&E Corporation Foundation.

Through multiple programs, PG&E's coworkers engage and support their communities on a local level:

- PG&E's **Community Service Incentive Program** provides coworkers and retirees who volunteer more than 25 personal service hours with a Community Service Award and grant of $350 on their behalf to a qualifying non-profit organization of their choice. In 2025, more than 400 employees logged enough hours to earn an award.
- PG&E's **Employee Resource Groups**—representing different aspects of PG&E's workforce—provide opportunities for engagement among community groups and activities that reflect their interests and priorities, including their own charitable contributions and scholarship programs.
- Through The PG&E Corporation Foundation's **Matching Gifts Program**, eligible gifts from PG&E coworkers and retirees are matched, dollar-for-dollar, up to $1,000 per calendar year per individual. In 2025, the program raised $9.3 million in support of 4,990 CBOs and schools.
- Coworkers also raised more than $856,000 through donations and matches from The PG&E Corporation Foundation through fundraisers for non-profits and schools through its **Peer-to-Peer Fundraisers program.**

In 2025, PG&E and The PG&E Corporation Foundation made over 1,000 charitable contributions to CBOs with an aggregate total of $32.9 million in charitable contributions. Coupled with the $3.7 million in contributions from the employee Matching Gifts Program, the aggregate charitable support for communities totaled $36.6 million in 2025.

Learn more about PG&E's impact, coworker involvement, and charitable guidelines at www.pge.com/giving. Anyone can also see PG&E's charitable contributions via its Giving Map at www.pge.com/givingmap.

c. LSEs' Tribal Customers

PG&E has taken significant steps to foster strong partnerships with tribal governments and their communities. There are 62 federally recognized tribes and 54 non-federally recognized tribes within PG&E service area. PG&E has a centralized tribal team of two liaisons, with over 45 years of experience, who actively engage with tribal governments, their staff, tribal health clinics and tribally chartered organizations. PG&E's emphasis on compliance in delivering safe and reliable energy services reflects the commitment to not only meeting regulatory requirements, but also to ensuring that all tribal governments and community customers have equitable access to safe, reliable and affordable services.

The Tribal liaisons collaborate with other internal departments, including all lines of business in both gas and electric, demonstrating a comprehensive approach to addressing the needs and interests of tribal communities. PG&E's Tribal team provides training to both staff who regularly engage with tribal governments, as well as others within the company, on indigenous cultures, histories, and protocols, to ensure that PG&E coworkers build respectful relationships and foster effective communication with tribes.

In partnership with other California investor-owned utilities (IOUs), PG&E hosts a Tribal Leaders Energy Summit (TLES) annually, bringing together Tribes and various stakeholders to discuss energy-related issues, new technologies and programs. The TLES provides a space for tribes to provide direct feedback to the IOUs, to meet with each other, and to consult directly with state and federal agencies.

d. Procurement Products

PG&E incorporates by reference Appendix A of its Updated 2026 BPP filed on June 1st, 2026[144] to describe the list of physical and financial products that PG&E may utilize in procurement activities associated with the portfolios presented herein. Please note that the actual mix of products PG&E uses to meet its portfolio needs may vary depending on changes to its load forecast, supply mix available, regulatory requirements and resource costs. Appendix A of PG&E's 2026 BPP update includes tables that provide product names, descriptions and citations to the initial regulatory authority approving procurement of those products. The decisions cited reflect the Commission's initial authorization for the listed products; subsequent

[144] R.25-06-019, filed June 1st, 2026 – Bundled Procurement Plan, Appendix A *Procurement Products*, File can be found here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M608/K066/608066401.PDF

decisions, advice letters, statutes, and CAISO tariff provisions governing specific structure and compliance.

e. Commission Direction of Actions

i. IRP Procurement Authority Request

As noted earlier in the Study Results Section III, PG&E anticipates that it will need to procure additional resources to meet its 2035 IRP GHG emissions reductions and GHG-free energy goals in all scenarios, and as early as 2030 for its scenarios A and E. However, the exact needs are highly dependent on the portfolio assumptions included in each scenario. This section will focus on the analysis for Scenarios B, C and D which include modifications for near-term build rates, technology mix and DCPP extension. These scenarios reflect a procurement need range for 4.6 - 6.6 GW[145] of incremental resources by 2035. While PG&E does not anticipate having a clean energy procurement need for 2030, it requests authority to begin soliciting for resources in 2027. Procurement of resources now facilitates early and gradual procurement to help mitigate against reliability and cost impacts of supply constraints or project delays and failures. PG&E will continue to work towards meeting its D.26-02-057 procurement requirements through its recent GHG-free RFO and may issue subsequent solicitations as needed. The ultimate quantity PG&E procures, as well as the year it procures towards is highly dependent on a number of factors including but not limited to, resource mix procured, changes in PG&E's load forecast, outcomes of ongoing regulatory proceedings, procurement resulting from future or existing mandates, project delays or failure, federal policy changes and customer affordability. PG&E will continue to update and refine its analysis and subsequent needs based on the latest available information.

Early and flexible procurement via the IRP proceeding aligns with similar requests made in PG&E's 2026 BPP update and in its Draft 2026 RPS Procurement Plan. This authority will help PG&E stay nimble in the face of future changes to its procurement need year and also allow it to balance procurement of more developed GHG-free technologies today while working towards procuring more emerging technologies further down the forecast horizon.

[145] Values represent nameplate capacity based on Study Analysis for scenarios B, C and D and include storage (e.g. Battery and pumped storage) capacity. These values exclude CPE allocations shown in resource addition tables in the study results sections. The ultimate quantity of resources procured may vary as a result of changes to underlying demand forecasts, requirements, resource mix or other factors. This procurement request is to begin procurement towards these needs regardless of such changes.

PG&E requests the Commission explicitly provide PG&E with procurement authority in its decision approving PG&E's 2026 IRP. PG&E proposes the following language be adopted by the Commission as an ordering paragraph that would provide PG&E with procurement authority to fulfill the procurement need identified by its 2022 IRP.

"PG&E is authorized to initiate resource procurement activities, including its own competitive solicitations, third party competitive solicitations and bilateral negotiations beginning in 2027, to meet the needs identified in its 2026 IRP or any subsequent update thereto approved by the Commission. Resources procured under this authorization may also count towards future procurement mandates or compliance requirements established by the Commission in this proceeding. PG&E shall submit a Tier 3 AL for approval of contracts for resources procured by PG&E pursuant to this ordering paragraph, unless such contracts are also authorized pursuant to any other proceeding before the Commission in which case such contracts may be presented pursuant to a Tier 1 AL or other approval vehicles permissible for similar products. For administrative efficiency, more than one contract may be presented to the Commission in each AL submission."

PG&E is seeking to procure both new and existing resources via procurement activities such as solicitations or bilateral negotiations. While solicitations may allow PG&E to better understand overall market depth, PG&E also seeks authority to procure via bilateral negotiations to ensure it can take advantage of any unique or fleeting opportunities on the market.

Potential for Need Year Change

As noted above, PG&E estimated IRP procurement need of approximately 5 GW of incremental resources by 2035 is based on the assumptions set forth in Scenarios C and D of this IRP filing. PG&E may ultimately procure a different total quantity or mix of resources should these underlying assumptions change. Specifically, any changes that impact PG&E forecasted need year will impact the quantity it procures. As noted in PG&E's Draft 2026 RPS Plan[146] PG&E's need year may change as a result of several factors:

- Changes in load forecast resulting from adoption of electrification, EVs, or energy efficiency technologies, future CCA load departure or load return and build-out of large data centers may impact PG&E's future RPS, GHG-free, GHG-emissions or reliability positions and subsequently its procurement need.

[146] PG&E's Draft 2026 RPS Plan (June 12, 2026) R.24.01-017, Section II: https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=877764 (accessed August 3, 2026)

- Commission-ordered mandated procurement (e.g., for reliability purposes, procurement orders via IRP, etc.) such as MTR and D.26-02-057, that include RPS-eligible or GHG-free resources may impact PG&E's future GHG-free position and subsequently its procurement need. These orders may also impact the specific types of resources that PG&E is seeking to procure.
- Changes in regulatory requirements, including those that may arise from a decision on the RCPPP staff proposal.
- Resolution on R.25-02-005 regarding treatment of pre-2019 Bank. Should the compensation structure established therein make use of Pre-2019 Bank not the most cost-effective means of RPS compliance, PG&E may have a procurement need for incremental RPS products, some of which may also impact its IRP clean energy positions.
- New laws increasing or expanding upon GHG-free or GHG-emissions requirements may change PG&E's total GHG-free energy need and/or change PG&E's need year.
- Centralized procurement conducted on behalf of PG&E such as from the Central Procurement Entity (CPE) or DWR may impact PG&E's portfolio and subsequently its overall procurement need.
- The available resource mix in the market to build or contract may impact PG&E's total need and ultimately its need year since different technologies have different marginal emissions reductions benefits. This may require more resources and potentially more time (or fewer resources depending on the generation profile) depending on what is available in the market. The resource types procured may also impact RA positions, favoring different resource types or different quantity of resources.
- Other unforeseen regulatory or market changes

Benefits of Gradual Procurement

Although there are several years until PG&E's 2030 need year, PG&E believes that beginning solicitations as soon as possible is prudent to achieve its IRP goals and procure resources gradually. For example, PG&E's CAISO system modeling results in Section III.n show a total system need for between 31 GW to 49 GW by 2030 and 64 GW to 95 GW by 2035. The high end requires a tripling of recent-year renewable resource build rates through 2030. These levels are greater than have ever occurred for California in single year. Procuring new GHG-free resources sooner and spreading procurement out more gradually over several years may help mitigate future risk including but not limited to:

- Uncertainties regarding project development timeframes including supply chain constraints or delays;

- Significant demand for projects, including new construction and emerging resources (e.g., OSW) as LSEs ramp up procurement for increasing RPS and GHG emission requirements for 2030 and beyond;
- Potential cost impacts due to state and federal policy changes in Investment or Production Tax Credits and/or tariffs on imported materials;
- Potential increase in demand due to increased electrification, EV adoption, data center load or load return;
- Potential transmission constraints for new projects, and potential scarcity of viable projects if required transmission infrastructure does not keep pace with the number of new resources needed; and
- Potential for competition for out-of-state resources as jurisdictions outside California increase their climate mitigation efforts.
- Over-procurement if data center load does not materialize.

In addition, PG&E has historically procured gradually to meet other goals such as RPS compliance[147] by layering procurement over multiple years. This strategy helps mitigate price and project failure risk while reducing the potential for over or under-procurement by allowing time to explore options and reassess market conditions as PG&E's supply portfolio and demand change. This strategy also better positions PG&E to adopt emerging technologies, pivot if needed for changing requirements and find more cost-effective options for meeting its portfolio needs. More detail on the attributes associated with the type of resources PG&E is seeking procurement authority for can be found in Table 49 below.

[147] PG&E's 2022 Draft RPS Plan (July 1, 2022) R.18-07-003, addresses the benefits of early procurement in Section IV.A.3, pp. 27 -31, <http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=709459> (as of August 3, 2026).

TABLE 49
IRP PROCUREMENT REQUEST PRODUCT INFORMATION

Attribute	Short-Term	Long or Intermediate-Term
PCC (if applicable)	PCC 1, PCC 2 or PCC3	PCC 1, PCC 2, or PCC3
Product and/or Deliverability Status*	Energy (zero-emitting), Energy + REC, REC Only, RA only	FCDS, PCDS, or EO, or RA only
Resource Vintage	Existing or New	Existing or New
Delivery Start Year**	2028 and beyond	2028 and beyond
Term	≤5 years	>5 years
Approval Vehicle	Tier 1 AL	Tier 3 AL
Technology Type	All zero-emitting resources, including RPS-eligible with or without Storage or standalone storage	All zero-emitting resources, including RPS-eligible with or without Storage or standalone storage
Resource Type	Third party	UOG or third party
Location	CAISO connected, pseudo tied or dynamically transferred	CAISO connected, pseudo tied or dynamically transferred
Method of Procurement	PG&E solicitations, bilateral transactions, other market participant solicitations, brokers, and exchange (if available)	RFO, bilateral, other market participant solicitations, brokers, and exchange (if available)
Volume Seeking	Amount based on IRP targets, bundled customer affordability goals, RPS requirements, CPUC procurement-related orders such as those arising from the IRP needs, other CPUC-ordered procurement, energy, GHG-free energy, and GHG-emissions reductions targets for the targeted time frame	Amount based on IRP targets, bundled customer affordability goals or RPS requirements, CPUC procurement-related orders such as those arising from the IRP needs, other CPUC ordered procurement, capacity, energy, GHG-free energy, and GHG-emissions reductions targets for the targeted time frame

Notes: *Full Capacity Deliverability Status (FCDS), Partial Capacity Deliverability Status (PCDS), or Energy Only (EO).
**Delivery start years are dependent on whether or not resources are being used to meet compliance for mandated procurement orders (may be as soon as 2028).

Generally, PG&E agrees that the programmatic approaches as opposed to solely procurement mandates could increase predictability, ensure alignment, allow flexibility, prevent leaning by

LSEs, and increase market efficiency while conducting planning, procurement, and operational activities to meet the state's climate goals. The procurement authorization request by PG&E would not necessarily be different under different procurement programs because PG&E's needs remain the same. That being said, the final outcome of the RCPPP may impact the way compliance is measured and give preference to certain resource types, attributes or timelines. While the specific types, quantities, and timeline for resources procured may change depending on the programmatic approach selected, PG&E believes that its proposal to procure gradually will allow us to adjust, if necessary, to any IRP procurement frameworks adopted by the Commission. This is because, ultimately, its procurement request aligns with the Commission's desired objective of co-optimizing future procurement to meet RPS, GHG-free energy, GHG-emissions, and reliability goals by taking a proactive LSE-driven approach that emphasizes sufficient planning time, commercial flexibility, and resource diversity. Additionally, PG&E plans to submit all short-term contracts for approval via the Tier 1 AL process, and all intermediate and long-term contracts via the Tier 3 AL process.

PG&E's request for procurement authority is based on its bundled portfolio needs which are based on the assumptions laid out in the presented scenarios. If the Commission adopts a non-need-based allocation approach going forward, PG&E's procurement request may be too low or too high. In addition, should the underlying assumptions that were used to calculate these needs change, for example changes in load forecast, portfolio mix or regulatory requirements, PG&E's calculated procurement need may change as well. PG&E continues to support need-based procurement allocations, in part because this approach encourages proactive actions by LSEs by removing risk associated with over-procurement due to non-need-based procurement decisions. To that end, PG&E requests that any procurement undertaken as a result of this procurement request count toward any procurement requirements adopted as part of a new programmatic procurement framework (e.g., would not be considered "baseline" for 2030 or 2035 need-driven procurement) or future CPUC-issued procurement related orders.

PG&E's request focuses on Scenarios B-D and therefore does not assume any centralized procurement on long-lead time GHG-free resources such as those that may be procured by AB-1373. PG&E encourages the Commission to adopt a programmatic approach that offers a predictable approach for any centralized procurement. Any centralized procurement or procurement mandates that are allocated on a load share basis should be communicated to LSEs in a timely manner, so that LSEs can incorporate such quantities, and types, of attributes from such additional resources to be procured in order to determine their impact on the LSEs'

remaining portfolio needs. As noted earlier in its Action Plan, any centralized procurement such as what may be executed by DWR, would impact PG&E's overall procurement need.

PG&E will provide additional details as part of comments filed in the RCPPP development process.

ii. New Spending Authorizations

PG&E will secure independent evaluation of its procurements by an Independent Evaluator (IE) to provide third-party oversight of any solicitation activities. PG&E proposes to recover the costs of the IE for any of the solicitations for procurement conducted on behalf of this request be included in the appropriate PABA subaccount.

iii. Changes to Existing Authorizations

PG&E currently has procurement authority for resources that may help meet the needs identified in its 2026 IRP. This authority is granted via D.24-02-047 approving PG&E's request in its 2022 IRP filing, as well as via existing procurement orders and authority from other proceedings. In its last IRP filing, PG&E requested and received authority to procure towards the needs identified therein. While this has allowed for PG&E's current procurement efforts like its GHG-free RFO, PG&E's 2026 IRP analysis identifies different needs, specifically resources that are needed further out. Therefore PG&E has included its updated request in this IRP filing.

The procurement order laid out in D.21-06-035 authorizes reliability procurement for resources with online dates mid-decade through 2028, while D.26-02-057 authorizes procurement of resources with online dates of 2029 through 2032. In addition to this, PG&E's current approved BPP authorizes transactions for contracts of shorter than 5 years for energy and capacity products. Earlier this year, PG&E filed an update to its BPP which is under review requesting expanded authority to procure RPS products with terms of up to five years, as well as expanded authority for other energy and capacity products of up to 10 years. Lastly, PG&E currently has procurement authority for RPS resources via its Final 2025 RPS Plan and has requested continued authority in its Draft 2026 RPS Plan based on its demonstrated RPS need and other portfolio management objectives including customer affordability presented there. PG&E is currently waiting to hear back on both its BPP and RPS plan requests.

Generally, PG&E is not seeking any changes to previously issued Commission procurement authorizations or procurement authorization currently under consideration by the Commission. Although procurement conducted for other purposes (e.g., RPS Compliance, portfolio optimization) may improve PG&E's GHG-free and GHG emissions positions, PG&E requests additional procurement authority in this filing based on the results from its 2026 IRP analysis.

This request will help PG&E procure in a measured manner to meet its 2035 and beyond IRP goals while offering the ability to adjust its executed procurement based on new supply, demand, and market information to reduce the likelihood of under or over-procurement. As noted above the need year PG&E procures for may move up based on a number of factors—PG&E feels that this procurement authority is prudent to be nimble should its IRP clean energy or reliability positions change.

While PG&E is not specifically requesting any additional Commission actions beyond the one request for procurement authorization in this IRP, PG&E encourages the Commission to consider potential actions which are currently open or will be filed in separate, future proceedings. PG&E has summarized these potential actions in the table below.

TABLE 50
SUMMARY OF PROPOSED NEW NEAR-TERM ACTIONS/COMMISSION DIRECTION OF ACTION

IV Action Plan Section	Proposed New Near-term Actions / Commission Direction	Reference
v. Renewable Energy	PG&E has submitted a request for continued and procurement authority in its Draft 2026 RPS Plan. PG&E has submitted a request for streamlined procurement authorization of certain short-term renewable energy products in its 2026 BPP update. PG&E is requesting continued procurement authority in this IRP filing. The CPUC should reconsider the feasibility of current 2030 emissions requirements for customer affordability and build-rate feasibility reasons. The CPUC should not issue interim procurement orders until a decision on the RCPPP is made. This decision should be informed by customer affordability and build-rate feasibility.	Table 35
viii. Energy Efficiency	Commission should approve PG&E's 2028 2035 EE Strategic Business Plan.	Table 37

v. Lessons Learned

About 1.5 months before submitting this Plan, the CPUC produced another option for potential structure of a Reliable and Clean Power Procurement Program (RCPPP).[148] The RCPPP is intended to help better determine more efficient and longer-term contracting procurement requirements for reliable and clean resources. This additional option leans heavily on the 2026 LSE Plans when determining system need, however the analysis was nearly complete by the time this option was released (and Plans were filed before any RCPPP decision was reached).

PG&E applauds the CPUC for examining a fundamental overhaul in this process to make the process more efficient, effective, and predictable, but cautions against setting compliance penalties based on new resources included in the 2026 Plans until feasibility of future emissions benchmarks are addressed. PG&E is pleased to participate in this separate process and believes that it is an appropriate forum for it and other LSEs to bring up suggested changes for consideration. Many of the lessons learned from this year's IRP cycle already appear to be teed up for discussion in the questionaries for the Reliable and Clean Power Procurement Program Staff Options Paper. PG&E offers the following additional recommendations to further improve the Commission's integrated resource planning.

a. Capacity Expansion Modeling Tool Enhancement

The grid and capacity modeling capabilities need to grow along with the planning challenges California is facing. PG&E recommends that the Commission enhance its capacity expansion modeling capabilities to ensure that the tools are adequate for addressing the existing and emerging resource planning challenges.

The Commission's use of a robust loss of load expectation model has improved reliability analysis occurring in the IRP proceedings; use of a similarly robust model for capacity expansion modeling and IRP portfolio development could be another modeling capability improvement that the Commission should consider.

Utilizing a more robust modeling software suite will allow more granular and robust analytics that can lead to improved planning. For example, the Commission's current capacity expansion tool dispatches resources by aggregate resource class to meet CAISO demand, with no zonal considerations and 37 representative days. A robust capacity expansion model would allow

[148] Administrative Law Judge's Ruling Seeking Comments on an Additional Proposal for Reliable and Clean Power Procurement Program, June 23, 2026. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M609/K223/609223925.PDF

individual unit dispatch to inform capacity expansion modeling with CAISO zonal considerations and annual 8,760 hourly functionality, improving modeling granularity. Similarly, it will provide greater flexibility for modeling demand side solutions as candidate resources, a feature crucial for successful implementation of advance load management solutions in the IRP.

While PG&E understands the Commission's intention to remain neutral and utilize the available RESOLVE model, many other organizations throughout the state are already using PLEXOS or other more sophisticated tools to perform similar analysis. For example, the CEC and CAISO are already using PLEXOS for reliability, capacity expansion, and/or production cost modeling. Many load-serving entities, including PG&E, also utilize PLEXOS. In fact, PG&E has used PLEXOS to produce hourly modeling outputs for this IRP, as noted in the "Study Design" section above. PG&E cannot speak for other load-serving entities, but it took months of debugging and troubleshooting RESOLVE, including support from the vendor, before PG&E could use it in this IRP. PLEXOS and other leading tools have more robust input and output reporting that streamlines the scenario development process and lends transparency to modeling results.

b. Planning for Reliability

A comprehensive reliability assessment is a key element of the IRP process. Acknowledging that recent IRP process improvements address some of the reliability assessment gaps, PG&E continues to recommend the following actions to ensure that a comprehensive reliability assessment is a part of CPUC's resource planning process:

i. Loss of Load Model Enhancement

PG&E applauds the Commission's ongoing efforts to improve its model assumptions and offers the following recommendations for further enhancement of the model:

- PG&E is encouraged to see that the Commission is now modeling the PG&E, SCE, and SDG&E TAC Areas separately and accounting for Path 26 constraints in capacity expansion and reliability modeling efforts. As a result, RESOLVE is selecting more candidate resources north of Path 26 (NP26) than it previously has. When assessing system reliability, the Commission should ensure that the new resources mapped to Northern California have a reasonable likelihood of actually being built. If barriers to new build are not addressed, the assumed capacity may not actually materialize which could have reliability implications if they are needed for Northern California reliability.
- The increased frequency and severity of extreme weather events in the past several years highlights the need for more work to adequately address the impacts of climate change. LOLE reliability modeling is designed to stochastically address uncertainty,

including variability due to weather. However, recent weather events suggest the LOLE framework may be inadequate to assure the desired levels of reliability. PG&E looks forward to engaging with the Commission and stakeholders on this fundamental planning issue. For immediate action, PG&E recommends that the Commission implement the following before finalizing the 2027 Preferred System Plan (PSP):

- The Commission should include weather conditions from 2023, 2024, and 2025 in reliability modeling. The core intent of LOLE reliability modeling is to stochastically capture uncertainty. The Commission recently incorporated weather years 2021-2022 and encourages the addition of weather years 2023, 2024, and 2025 to ensure alignment with the most recent data available. Given the unprecedented load seen in September 2022, incorporating this year should better reflect load uncertainty. However, 2023 saw dry hydroelectric conditions throughout the WECC and 2024 also saw higher-than-average peak demand[149].
- The Commission should utilize the CEC's 2025 Integrated Energy Policy Report (IEPR) in RESOLVE and SERVM. The 2025 IEPR forecast was approved by the CEC in February 2026. This IEPR forecast update has incorporated improved electrification demand forecasts and uncertainty in data center demand. The underlying load forecast has a significant impact on IRP portfolios developed through RESOLVE capacity expansion modeling. Ensuring the most recent and accurate load forecast is used is critical to meeting reliability requirements and the determined reliability of the portfolio assessed in SERVM production cost modeling. ED should have sufficient time between the release of the 2025 IEPR in February 2026 and the potential 2027-2028 TPP ruling in Q1 2027 to incorporate the 2025 IEPR forecast.
- For future modeling enhancement to capture the impact of load management solutions on LOLE, PG&E asks the Commission to create a separate workstream focused on all aspects of load management solution modeling in the IRP. Modeling of load management in the IRP will not be a trivial task. It requires a dedicated stakeholder process to ensure that the IRP models are capable of providing cost-effective supply and demand side solutions to address reliability

[149] California ISO Peak Load History 1998 through 2025. https://www.caiso.com/documents/californiaisopeakloadhistory.pdf (accessed August 3, 2026)

and GHG emission reduction goals in a cost-effective manner. See additional details below in the Integrated Planning section.

ii. Local Reliability Assessment

The lack of a local reliability assessment continues to be a gap in the IRP process that needs to be addressed immediately. The Assigned Commissioner's Ruling related to identifying replacement resources (including local capacity need) to allow the retirement of Aliso Canyon[150] highlights the needs for a systematic and coordinated effort between the CAISO and the CPUC to develop a plan for local area capacity requirements[151] to address the local need in a timely manner.

A significant amount of existing capacity on the CAISO system is located in local areas. These local areas must rely on local resources due to transmission limitations. Typically, the local area resource requirements are met by existing resources. As long as the existing resources do not retire or local area loads do not increase significantly, a local capacity resource need assessment is not required. However, given the aging gas-fired resources and plan for significant load growth due to electrification demand (building and transportation), conducting a local capacity need assessment should be in scope of CPUC's IRP process in close co-ordination with the CAISO. The CAISO is in the best position to provide details on location specific resource requirements and support the identification of an integrated, cost-effective solution (e.g., portfolio of resources, transmission alternatives) to adequately address location specific requirements.

[150] Assigned Commissioner's Ruling Entering Into the Record Energy Division Proposal and Ordering Testimony (Sept. 23, 2022) I17-02-002, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M497/K170/497170260.PDF>

[151] Per 2022-23 CAISO TPP Study Plan, since Aliso Canyon supports electric generation located in the Los Angeles (LA) Basin its closure could have "potential reliability impacts to the transmission facilities in the LA Basin and to some extent San Diego Imperial Valley local capacity areas in the CAISO Balancing Authority Area… ." CAISO, 2022-2023 Transmission Planning Process Unified Planning assumptions and Study Plan, Rev. 1 (June 30, 2022), pp. 77-78, Section 7.1, < http://www.caiso.com/InitiativeDocuments/FinalStudyPlan-2022-2023TransmissionPlanningProcess.pdf> (as of August 3, 2026).

c. Improvement in Key IRP Modeling Assumptions and Assessing Uncertainty

i. Future Portfolios Should Incorporate More Up-to-Date Modeling Assumptions

When LSEs file their 2026 IRPs on August 10, 2026, the system modeling provided by the Commission will be more than a year old.[152] For example, the inputs and assumptions used in this filing were developed in early to mid-2025 and did not capture significant shifts in the energy landscape such as the federal OBBBA which greatly impact resource cost.[153] Additionally, the 2026 Filing Requirements utilize the CEC's 2024 IEPR load forecast, approved in February, 2025. Since then, the CEC has released the 2025 IEPR which averages 9.7% lower than the 2024 IEPR from 2028 through 2045. Since LSEs are required to utilize these assumptions for IRP compliance, this results in portfolios that are outdated even before they are published.

PG&E has attempted to account for some of these issues by utilizing more recent 26-27 TPP cost assumptions and incorporating near-term feasibility into resource additions into alternate scenarios, but PG&E is limited in what it can change while remaining compliant. In future IRP analyses, PG&E recommends that the Commission utilize more up-to-date assumptions, if applicable. If not, PG&E recommends that the Commission allow LSEs to update more assumptions and remain compliant. PG&E recognizes allowing LSEs to make any discretionary updates could lead to inconsistent portfolios but believes this can be mitigated by allowing LSEs to incorporate more recent versions of Commission-approved assumptions, such as utilizing the latest CEC IEPR load forecast. In the case where this could lead to incomplete updates, such as updating only one technology cost to the latest NREL source, the Commission could specify that an LSE must update all applicable assumptions to that latest source rather than simply one technology or assumption. This flexibility will allow LSEs to produce more relevant Plans that inform important Commission analyses such as PSP and TPP development.

[152] The conforming case results viewer is dated July 14, 2025. See "2026 CPUC Filing Requirements Modeling (1/16/2026)" link on the 2024-2027 IRP Cycle page. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2024-27-irp-cycle-events-and-materials (accessed August 3, 2026).

[153] Final 2025 I&A slides for the 2024-2026 IRP Cycle, slide 6. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_slides-20260210.pdf (accessed August 3, 2026)

ii. Robust Scenario Analysis Identifies Least-Regrets Actions

As noted in the OIR, from 2019-2024, the IRP proceeding procurement track has resulted in orders for significant quantities of new reliable and clean energy resources to be procured by LSEs in California.[154] These procurement orders largely preceded the explosion of activity across the energy sector with respect to new large loads such as data centers and advanced manufacturing. Given the scale of this potential load[155] and the impact it will have on both planning models and procurement processes, it is imperative that the Commission consider a range of possible outcomes so California does not overbuild and create stranded assets that have negative implications for long-term customer affordability, while at the same time ensuring the grid is reliable and not a constraint on economic growth in California.

This IRP proceeding is uniquely suited to building a framework to manage this uncertainty through careful planning scenarios that examine a range of possible outcomes of load, resources and other drivers. Scenarios and sensitivities have been included in past IRP cycles, yet most planning activities, such as transmission planning and resource procurement, are centered on a single base case resource portfolio. PG&E believes further exploration of the drivers of new resources (e.g., scale, location, type) and a comparison across scenarios should be a core output of the PSP. This will help the CAISO, LSEs and utility distribution companies identify which investments and procurements are necessary across all potential outcomes, thus establishing a "least regrets" pathway that will be robust to changing external policy and other factors. PG&E looks forward to engaging further with the Commission through its LSE plan and the PSP development process to incorporate this important work in IRP outputs.

PG&E provides an example of "least regrets" planning in Scenario C of this IRP by demonstrating that extending Diablo Canyon Power Plant operations through 2045 is a prudent, no-regrets strategy that supports affordability, reliability, and decarbonization objectives. PG&E also demonstrates how more feasible near-term resource build can impact emissions and cost and how reassessing interim GHG targets can result in customer affordability benefits. Incorporating more robust scenario analysis into future IRP portfolios will

[154] R.25-06-019, pages 6-7. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M571/K276/571276511.PDF

[155] CEC, Docket Number 24-IEPR-03, Presentation - 2024 California Energy Demand Annual Consumption and Sales Forecast Results, dated Dec. 11, 2024, slide 13 (indicating a 34 TWh higher sales forecast in 2024 IEPR compared to 2023 IEPR), available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=260599&DocumentContentId=96897 (accessed August 3, 2026).

allow the Commission and stakeholders to better understand the tradeoffs between different options and lend additional credibility that portfolios utilized in future planning efforts best address reliability, affordability, and decarbonization concerns.

iii. Existing Resource and Assumptions

As described in Section III.g, PG&E recognizes that the issue of future contract assumptions for existing resources, both GHG-free and GHG-emitting, is critical to address to improve the LSE planning process for future IRP cycles. Without a prescribed approach from the CPUC, aggregated LSE plans are likely to misrepresent existing resources and be misaligned with the updated PSPs.

One solution for the CPUC to consider is proportionally allocating the GHG-free energy attributes and both GHG-free and GHG-emitting reliability attributes from existing resources for all years after their existing contracts expire through the planned retirement date assumed for each resource. The list of applicable resources and future contract expiration dates can be determined based on the CPUC's system resource dataset and LSEs' annual RDT submittals that include details regarding their contract portfolios. This would ensure a more equitable representation of planned new procurement across LSEs within their IRPs while actual future LSE procurement will likely be a combination of agreements with both new and existing generators.

d. Integrated Planning

As stated on the CPUC's website,[156] the intent of the IRP proceeding is to be "an umbrella planning proceeding to consider all of the Commission's electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply". PG&E agrees with the intent. Given the increasing opportunity to include CCS and load management solutions to support the state goals and the need to consider cost-effective infrastructure upgrades that interact with supply and demand side solutions, PG&E offers the following recommendation to systematically fill in the planning gaps and complete the transition for the IRP proceeding to truly become an umbrella planning proceeding:

i. Carbon Capture and Sequestration

As noted in Section III.j above on Clean Firm Power Planning, Carbon Capture and Sequestration (CCS) is missing in the Commission's modeling for the 2026 IRPs even though CARB identifies

[156] Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP), https://www.cpuc.ca.gov/irp (accessed August 3, 2026).

this technology as important to meeting the GHG emission reduction targets that underly these Plans.

Given the importance in the Scoping Plan and as noted in comments on the 26-27 TPP, PG&E recommends incorporating CCS as a retrofit candidate for existing natural gas plants. Given the declining natural gas generation in the forecast horizon, CCS retrofits should be modeled to determine what role technology may play in a future resource mix. PG&E understands that the Commission is currently working on incorporating this technology into the next TPP cycle[157] and urges the Commission to consider this technology in IRP modeling before procurement decisions are made for 2035 and beyond.

ii. BTM Resource and Load Management Solutions Modeling

As noted in the Executive Summary, the Commission has not enabled the consideration of Vehicle to Grid Integration (VGI) as a candidate resource even though the module was developed for the Commission's 2023 Preferred System Plan. PG&E encourages the Commission to update VGI assumptions and further integrate advanced load management (ALM) resources into the IRP optimization process.

Recognizing the needed effort and wanting to ensure adequate time and attention for this important task, PG&E asks the Commission to start a separate IRP track to: (i) fully develop modeling capabilities, (ii) identify and streamline (or consolidate) interactions with other demand side proceedings, and (iii) establish workable interactions with the CEC IEPR and CAISO TPP processes to ensure that the state is ready to seamlessly consider demand- and supply-side cost-effective solutions in its planning efforts.

Critical to this effort will be close coordination with the CEC's load forecasting efforts to ensure resources are not double-counted as both demand modifiers and supply resources, as well as other DER planning proceedings at the CPUC and CEC that are investigating optimal investments in DERs. Equally important will be coordination with transmission and distribution planning to ensure impact of demand side solutions on transmission and distributions systems is captured in a timely manner. Lastly, validating potential demand side solutions with customers for inclusion in the model is important. PG&E will be launching several CPUC-approved VGI pilots in the next year and would be willing to share data and lessons learned about enrollment and costs of VGI programs to help inform this modeling effort.

[157] D.26-02-057, pages 58-59.

VI. Glossary of Terms

A.: Application

AB: Assembly Bill

AFN: Access and Functional Needs Customers

AL: Advice Letter

ALJ: Administrative Law Judge

Alternative Portfolio: LSEs are permitted to submit "Alternative Portfolios" developed from scenarios using different assumptions from those used in the Preferred System Plan with updates. Any deviations from the "Conforming Portfolio" must be explained and justified.

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

ATE: Additional Transportation Electrification

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

BART: Bay Area Rapid Transit

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

BESS: Battery Energy Storage System

BEV: Business Electric Vehicle

BioMAT: Bioenergy Market Adjusting Tariff

BioRAM: Bioenergy Renewable Action Mechanism

BIP: Base Interruptible Program

BPOT: Bundled Portfolio Optimization Tool

Breakthrough Load Management and Emerging Technologies: Breakthrough load management and emerging technologies includes utilizing newer technologies (e.g., hydrogen and carbon capture, utilization, and sequestration) and includes accelerated adoption by customers of DER programs (PV and storage), smart technologies (EVs, smart thermostats and appliances) and efficiency measures to turn behind the meter and distributed resources into dispatchable resources.

BTM: Behind the Meter

BYOT: Bring Your Own Thermostat

C-PAC: Community Perspectives Advisory Council

CAISO: California Independent System Operator

CalEPA: California Environmental Protection Agency

CAM: Cost Allocation Mechanism

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

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

CAPK: Community Action Partnership of Kern County

CARB: California Air Resources Board

CARE: California Alternative Rates for Energy

CBO: Community Based Organization

CBP: Capacity Bidding Program

CCA: Community Choice Aggregators

CCS: Carbon Capture and Sequestration

CEC: California Energy Commission

CES: Clean Energy Standard (term reported by Commission in RESOLVE modeling, not yet a formal standard like RPS)

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

CHP: Combined Heat and Power

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

CO_2: Carbon Dioxide

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

Conforming Portfolio: The LSE portfolio that conforms to IRP Planning Standards, the 2030 and 2035 LSE-specific GHG Emissions Benchmark, use of the LSE's assigned load forecast, use of inputs and assumptions matching those used in developing the Preferred System Portfolio, as well as other IRP requirements including the filing of a complete Narrative Template, a Resource Data Template and Clean System Power Calculator.

CPE: Central Procurement Entity

CPUC or Commission: California Public Utilities Commission

CS-GT: Community Solar Green Tariff

D.: Decision

DA: Direct Access

DAC: Disadvantaged Communities

DAC-GT: Disadvantaged Communities Green Tariff

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

DCFC: Direct Current Fast Charging

DCPP: Diablo Canyon Nuclear Power Plant

DER: Distributed Energy Resource

DG: Distributed Generation

DR: Demand Response

DRAM: Demand Response Auction Mechanism

DRP: Demand Response Provider

DSM: Demand-Side Management

E3: Energy and Environmental Economics

ED: Energy Division

EDROIR: Enhanced Demand Response Order Instituting Rulemaking (R.25-09-004)

EDU: Electric Distribution Utility

EE: Energy Efficiency

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

Effective Megawatts (MW): Perfect capacity equivalent MW, such as the MW calculated by applying an ELCC % multiplier to nameplate MW.

EGS: Enhanced Geothermal System

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

ELRP: Emergency Load Reduction Program

ERRA: Energy Resource Recovery Account

ESA: Energy Savings Assistance

EV: Electric Vehicles

FERA: Family Electric Rate Assistance

FERC: Federal Energy Regulatory Commission

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

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

GHG: Greenhouse Gas

GHG Benchmark (or LSE-specific 2030 and 2035 GHG Benchmarks): The mass-based GHG emission planning targets calculated by staff for each LSE based on the methodology established by the California Air Resources Board and required for use in LSE Portfolio development in IRP.

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

GRC: General Rate Case

GTSR: Green Tariff Shared Renewables

GW: Gigawatts

GWh: Gigawatt-hour

IAWG: Inter-Agency Working Group

IE: Independent Evaluator

IEPR: Integrated Energy Policy Report

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

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

IOU: Investor-Owned Utility

IRA: Inflation Reduction Act of 2022

IRP: Integrated Resource Planning

kW: Kilowatt

kWh: Kilowatt-hour

lbs.: Pounds

LCOE: Levelized Cost of Energy

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

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

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

Long term: More than 5 years unless otherwise specified.

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

LSE: Load Serving Entity

MASH: Multifamily Affordable Solar Housing

Maximum Import Capability: A California ISO metric that represents a quantity in MW of imports determined by the CAISO to be simultaneously deliverable to the aggregate of load in the ISO's Balancing Authority (BAA) Area and thus eligible for use in the Resource Adequacy process. The California ISO assess a MIC MW value for each intertie into the ISO's BAA and allocated yearly to the LSEs. A LSE's RA import showings are limited to its share of the MIC at each intertie.

MDV: Medium Duty Vehicle

MMBtu: millions of British Thermal Units

MMT: million Metric Ton

MTR: 2023-26 Mid-Term Reliability

MW: Megawatts

MWh: Megawatt-hour

NEM: Net Energy Metering

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

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

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

NOx: Nitrogen Oxide

O&M: operations and maintenance

OBBBA: One Big Beautiful Bill Act

OIR: Order Instituting Rulemaking

Ongoing CTC: Ongoing Competition Transition Charge

OOS: Out of State

OP: Ordering Paragraph

Optimization: An exercise undertaken in the CPUC's Integrated Resource Planning (IRP) process using a capacity expansion model to identify a least-cost portfolio of electricity

resources for meeting specific policy constraints, such as GHG reduction or RPS targets, while maintaining reliability given a set of assumptions about the future. Optimization in IRP considers resources assumed to be online over the planning horizon (baseline resources), some of which the model may choose not to retain, and additional resources (candidate resources) that the model is able to select to meet future grid needs.

OSW: Offshore Wind

P^3: Procurement Portfolio Planner

PA: Program Administrator

PCC: Portfolio Content Categories

P&G: Potential & Goals

PCIA: Power Charge Indifference Adjustment

PDP: Peak Day Pricing

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

PM: Particulate Matter

PPA: Power Purchase Agreement

PRM: Planning Reserve Margin

Preferred System Plan (PSP): The Commission's integrated resource plan composed of both the aggregation of LSE portfolios (e.g., Preferred System Portfolio) and the set of actions necessary to implement that portfolio (e.g., Preferred System Action Plan).

Preferred System Portfolio: The combined portfolios of individual LSEs within the CAISO, aggregated, reviewed, and possibly modified by Commission staff as a proposal to the Commission, and adopted by the Commission as most responsive to statutory requirements per Pub. Util. Code 454.51; part of the Preferred System Plan.

PSPS: Public Safety Power Shutoff

Pub. Util. Code: Public Utilities Code

PURPA: Public Utility Regulatory Policies Act of 1978

PV: Photovoltaic

QF: Qualifying Facility

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

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

R.: Rulemaking

RA: Resource Adequacy

RAM: Renewable Auction Mechanism

RCP: Representative Concentration Pathway

REC: Renewable Energy Credit

ReMAT: Renewable Market Adjusting Tariff

RFO: Request for Offers

RPS: Renewables Portfolio Standard

RSBA: Reliability Services Balancing Account

RSP: Reference System Plan

SABR: System Average Bundled Rate

SADR: System Average Delivery Rate

SASH: Single Family Affordable Solar Homes

SB: Senate Bill

SCE: Southern California Edison Company

SDG&E: San Diego Gas & Electric Company

SGIP: Self-Generation Incentive Program

SmartAC: Smart Air Conditioner Programs

SOMAH: Solar on Multifamily Affordable Housing program

SOD: Slice-of-Day

SOx: Sulfur Oxide

SQL: Structured Query Language

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

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

T&D: Transmission and Distribution

TACBA: Transmission Access Charge Balancing Account

TLES: Tribal Leaders Energy Summit

TMNBC: Tree Mortality Non-bypassable Charge

TO: Transmission Owner

TOU: Time-Of-Use

Transmission Planning Process (TPP): Annual process conducted by the California Independent System Operator (CAISO) to identify potential transmission system limitations and areas that need reinforcements over a 10-year horizon.

TRBA: Transmission Revenue Balancing Account

TSB: Total System Benefit

TWh: Terawatt-hour

U.S.: United States

UOG: Utility-Owned Generation

V2G: Vehicle-to-Grid

VAMO: Voluntary Allocation Market Offer

VGI: Vehicle to Grid Integration

WECC: Western Electricity Coordinating Council

ZEV: Zero-Emission Vehicle

VII. Appendix 1: PG&E's Current Procurement Activity

PG&E's two current RFOs are listed in Table 51 below. For a more comprehensive list of RFOs, including prior RFOs, please refer to PG&E's Wholesale Electric Power Procurement webpage.[158]

TABLE 51
PG&E PROCUREMENT SOLICITATION ACTIVITIES

	Program	Description	Website
A	GHG Free RFO	PG&E is seeking bundled energy, PCC1 RECs, and capacity from new RPS-eligible resources with delivery dates from 2027–2032 to meet 2030+ resource needs and fulfill IRP procurement requirements under D.26-02-057.	https://www.pge.com/en/about/doing-business-with-pge/wholesale-electric-power-procurement/ghg-free-rfo.html
B	Disadvantaged Communities ("DAC") RFO	Purchase of energy from new solar resources located in Disadvantaged Communities.	https://www.pge.com/en/about/doing-business-with-pge/wholesale-electric-power-procurement/winter-2025-delayed-disadvantaged-communities-rfo.html

[158] PG&E, Purchasing wholesale electric energy and capacity, https://www.pge.com/en/about/doing-business-with-pge/wholesale-electric-power-procurement.html (accessed August 3, 2026).

EXCEL WORKBOOKS SUPPORTING PG&E'S 2026 PLAN

PG&E's Plan includes Excel workbooks, which will be filed via hard copy on archival CD-ROM with the Commission's Docket Office. The electronic filing does not contain these workbooks. The public version of these workbooks are accessible as follows:

1) Go to: https://pgera.azurewebsites.net/Regulation/search
2) Select "Electric Integrated Resource Planning Oversight OIR [R.25-06-019] from the case dropdown menu"
3) Select "PGE" from the party dropdown menu
4) Input the date from "08/10/2026" to "08/10/2026"
5) Click Search