PACIFIC GAS AND ELECTRIC COMPANY

CORE PROCUREMENT INCENTIVE MECHANISM (CPIM)
Application 96-08-043

November 1, 2022 through October 31, 2023
CPIM Year 30

Before the California Public Utilities Commission
July 29, 2025

PUBLIC VERSION

Pacific Gas and Electric Company

CPIM Annual Performance Report

November 1, 2022 through October 31, 2023

Year 30

1. Introduction

This report, filed with the California Public Utilities Commission (Commission) in compliance with Decision (D.) 97-08-055, documents the performance of Pacific Gas and Electric Company (PG&E) under the Core Procurement Incentive Mechanism (CPIM) for the period of November 1, 2022, through October 31, 2023 (CPIM Year 30).[1] During CPIM Year 30, PG&E served its core gas customers reliably, while achieving savings relative to the CPIM Benchmark. As documented in Tables I and II, PG&E's core gas costs and reservation charges were $196,846,016 below the CPIM Benchmark. Under the CPIM sharing formula, PG&E's core gas customers receive 100% of savings within the CPIM "Tolerance Band,"[2] 80% of the savings below the "Lower Limit" of the "Tolerance Band," and 100% of savings in excess of the shareholder award cap, resulting in a customer savings of $170,216,532. In

1 PG&E's Gas Accord Application (A.) 96-08-043, Supplemental Report Describing the Post-1997 Core Procurement Incentive Mechanism, October 18, 1996 (CPIM Supplemental Report). In D.97-08-055, the Commission approved a CPIM mechanism for core gas costs incurred after December 31, 1997 (Post-1997 CPIM). In that decision, the Commission ordered PG&E to file quarterly and annual reports on core procurement operations commencing 30 days after completion of one year of Gas Accord operating experience (Sixth Interim Order, D.97-08-055, Ordering Paragraph (OP) 10).

2 The Tolerance Band is the cost range of 99% ("Lower Limit") to 102% ("Upper Limit") of the CPIM Benchmark as defined in Table 1 of this report. Savings within the Tolerance Band are achieved if costs fall within 99-100% of the CPIM Benchmark.

accordance with the CPIM sharing formula and shareholder award cap, PG&E requests a shareholder award of $26,629,484.

The CPIM Annual Performance Report provides the Commission's Public Advocates Office (Cal Advocates)[3] and the Commission's Energy Division an opportunity to review PG&E's core procurement costs, PG&E's calculation of costs or savings to core gas customers, and any resulting shareholder penalty or award. The reporting, evaluation, and approval process described below is consistent with the procedures utilized in PG&E's previous CPIM years.

2. CPIM Overview

The CPIM provides PG&E with a financial incentive to procure and manage gas supplies, transportation, and storage assets in a manner that results in the lowest reasonable amount of core customer costs. The CPIM calculates shareholder awards or penalties through a comparison of total gas costs to the CPIM Benchmark, a market-based composite benchmark as described in Section 5 below. If total gas costs fall within the Tolerance Band, above or below the Benchmark, all costs are allocated to gas customers. If total gas costs fall outside of the Tolerance Band, then the costs or savings outside of the Tolerance Band are shared between gas customers and PG&E shareholders. For any savings, the shared amount is up to the shareholder award cap.[4] The CPIM performance is calculated annually, and any associated

[3] Formerly known as the "Office of Ratepayer Advocates".

[4] In these scenarios, costs are fully recovered from gas customers, net of any shareholder award or penalty.

shareholder award or penalty is recorded in the Core Sales Subaccount of the Purchased Gas Account, a balancing account that records the commodity, transport, storage and hedging costs associated with gas procurement for core customers.

The CPIM provides a standard benchmark that applies to purchasing activities occurring under most operating and temperature conditions. PG&E may elect an alternate benchmark if extraordinary circumstances require diversions of gas supplies to serve core customers, or if other highly unusual measures are necessary to ensure core reliability. PG&E did not elect an alternate benchmark during CPIM Year 30. Therefore, only the standard benchmark is reflected in this report.

3. Procedural Background and Modifications

On August 1, 1997, the Commission issued D.97-08-055 (the Gas Accord Decision), which approved the CPIM and established the methodology to recover PG&E's core gas procurement, storage and transportation costs in customer rates for the period from January 1, 1998, to December 31, 2002.[5] In D.02-08-070 (the Gas Accord II Decision) and D.03-12-061 (PG&E Gas Structure and Rates Settlement), the Commission extended the recovery of core gas procurement, storage and transportation costs (by way of the CPIM) and set the extension to terminate on the earlier of: (1) December 31, 2005; or (2) when a revised CPIM was adopted by the Commission.

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5 Appendix 1 to the Gas Accord Settlement Agreement, page 57, filed with the Commission on August 21, 1996, indicated that PG&E would file a CPIM applicable to the Gas Accord period. Appendix 1 was incorporated into D.97-08-055 (see D.97-08-055, Appendix B).

In the proceeding requiring California energy utilities to preserve interstate pipeline capacity to California in Rulemaking (R.) 02-06-041, PG&E and Cal Advocates reached an agreement that addressed modifications to PG&E's CPIM, including a provision that: "[t]he CPIM will continue until either [Cal Advocates] or PG&E proposes modifications and those modifications are approved by the Commission." This agreement, which is Exhibit 1 of R.02-06-041, was approved by the Commission in D.04-01-047, at Finding of Fact 12. In D.04-12-050, Conclusion of Law (COL) 8 (the Gas Accord III Decision), the Commission made no substantive changes to the CPIM. In D.10-01-023, the Commission approved the CPIM Hedging Settlement Agreement adopting the inclusion of winter hedging transactions in CPIM and set a shareholder earnings cap at 1.5% of annual gas commodity costs.

Core portfolio cost recovery is to be consistent with the PG&E/Cal Advocates Post-1997 CPIM Agreement dated October 16, 1996 (Post-1997 CPIM Agreement); PG&E's Supplemental Report Describing the Post-1997 CPIM, dated October 18, 1996 (CPIM Supplemental Report), filed in A.96-08-043 and approved in D.97-08-055; and the Cal Advocates/PG&E Memorandum of Understanding (MOU) addressing certain procedural details (attached as Appendix A in the 1999 report).

In June 2012, a petition for modification of D.04-09-022 was filed by a consortium of Core Transport Agents (CTA), seeking to modify the requirement that PG&E hold an amount of interstate pipeline capacity within specified ranges, to serve PG&E's bundled core customers as well as core customers served by CTAs. The Commission issued D.12-12-006 in response to the CTA's petition, establishing a new interim capacity range for PG&E's interstate pipeline contracts, and required PG&E to file an application to establish a new, permanent interstate capacity range. As directed by the Commission, PG&E filed Application (A.) 13-06-011 to revise its core interstate pipeline capacity planning range.

In October 2015, the Commission issued D.15-10-050, adopting an interstate pipeline capacity range for PG&E's core customers, including those served by CTAs. In accordance with the D.15-10-050, PG&E established its April through October core interstate pipeline capacity planning range between 80% and 105% of forecast average annual daily core demand, and its November through March range between 100% and 115% of forecast average annual daily core demand.

In June 2016, the Commission approved PG&E's 2015 Gas Transmission and Storage (GT&S) Rate Case (D.16-06-056), to (1) modify the firm storage winter withdrawal quantities; (2) include a monthly index component at PG&E Citygate into the CPIM Benchmark in addition to the daily price index; and (3) change PG&E's CPIM (upon agreement between PG&E and Cal Advocates) for determination of PG&E's CPIM Benchmark, including the method of calculating the benchmark load, the setting of the CPIM Benchmark sequence, the items to be included in the calculation of the capacity demand charges CPIM Benchmark, and the determination of benchmark gas index prices.

On April 3, 2018, Cal Advocates and PG&E Core Gas Supply (CGS) signed an MOU to implement the Modification to the CPIM incorporating the United States Customs and Border Protection's Merchandise Processing Fee (MPF) into the Benchmark. PG&E and Cal Advocates agreed to include the MPF associated with Canadian gas purchases in CPIM Actual and the Benchmark costs of the CPIM year in which the costs were incurred.

On January 11, 2019, Cal Advocates and PG&E CGS signed a MOU to implement the Modification to the CPIM incorporating biomethane purchased at PG&E Citygate for Compressed Natural Gas vehicle use in the CPIM Actual United States (U.S.) gas cost, as well as the CPIM Benchmark cost. The biomethane purchased at PG&E Citygate will be recorded separately under the CPIM and excluded from the benchmark load sequencing.

The 2019 GT&S Rate Case Final Decision (D.19-09-025) adopted PG&E CGS's portfolio modifying gas storage and intrastate pipeline capacities. Given the portfolio changes, conforming modifications to CPIM were needed for the pipeline sequence, storage profile, benchmark load, and storage inventory requirements. A Malin Monthly Index Firm block was added in addition to the Alberta Energy Company (AECO), Rockies and San Juan Firm Blocks, and a Malin Daily Index Block was added to sequence before or after PG&E Topock Daily Index Block, depending on least cost net forward price to the PG&E Citygate. The Kingsgate mismatch[6] volumes were moved into the new Malin Intrastate Sequence Block. The CPIM Benchmark sequence modifications are effective when the related pipeline assets

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6 Kingsgate mismatch until the early 2000's was approximately 25,000 Dth representing excess Gas Transmission Northwest (GTN) greater than the upstream pipelines' (NOVA Gas Transmission Ltd. (Nova) and Foothills Pipe Lines, Ltd. (Foothills)) delivery contract capacity. Foothills and Nova capacity was then acquired to reconcile the interconnection mismatch, and the ensuing Kingsgate mismatch was significantly reduced and primarily driven by GTN's monthly fuel rate changes.

are in the core portfolio. On July 2, 2020, the Cal Advocates and PG&E CGS signed an MOU modifying the CPIM effective April 1, 2020.[7]

In D.19-09-025, the Commission also approved the following changes to D.15-10-050:

1) Increase the winter range maximum from 115 percent to 162 percent of the average annual daily demand; and

2) Reduce the March range minimum from 100 percent to 80 percent of the average annual daily demand.

For CPIM Year 30, the effective interstate capacity planning ranges are in the table below (sources: Advice Letter (AL) 4324-G dated October 16, 2020 and AL 4647-G dated August 25, 2022):

Line No.	Season	Minimum Capacity Holding (MDth/d)	Maximum Capacity Holding (MDth/d)
1	Apr. 2023 – Oct. 2023	573	752
2	Nov. 2022 – Feb. 2023	770	1,247
3	Mar. 2023	616	1,247

4. <u>CPIM Year 30 Performance Results</u>

For CPIM Year 30, the Benchmark is $2,282,982,247, and total gas cost is $2,086,136,231, or 91.4% of the Benchmark. As specified in (1) CPIM Supplemental Report, Chapter 2, Part III, Incentive Rewards and Penalties,[8] (2) PG&E's Gas Preliminary Statement Part C, and (3) CPIM Hedging Settlement Agreement, all gas cost savings below the "Lower Limit" of the Tolerance Band are subject to sharing

7 AL 4271-G, MOU Between PG&E CGS and the Cal Advocates.

8 See Footnote 1.

between core gas customers and PG&E shareholders. For CPIM Year 30, PG&E core gas customers received 80% of the savings below the “Lower Limit” of the “Tolerance Band.”

Table I shows that PG&E’s actual gas costs are $196,846,016 below the CPIM Benchmark, of which $177,132,371 are below the Tolerance Band, yielding a shareholder award of $26,629,484. PG&E requests that Cal Advocates confirm the gas cost benchmark and performance calculations, and recommends to the Commission that PG&E’s shareholders be awarded $26,629,484 for CPIM Year 30.[9]

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9 The shareholder incentive award formula is described in the CPIM Supplemental Report, Chapter 2, Part III, Section B, Sharing Outside of the Tolerance Band. The Commission approved modifications to this formula in the Settlement Agreement dated December 15, 2006, included as Appendix A to D.07-06-013 and in the Settlement Agreement dated June 26, 2008, included as Appendix A to D.10-01-023 (R.08-06-025).

TABLE I
CPIM YEAR 30 PERFORMANCE SUMMARY NOVEMBER 1, 2022 – OCTOBER 31, 2023

Total Commodity, Transportation and Storage Costs							
Tolerance Band			**Actual Costs**				
Upper Tolerance Limit (Benchmark + 2.0% Commodity Benchmark)	Total Benchmark	Lower Tolerance Limit (Benchmark – 1.0% Commodity Benchmark)	Total Costs Incurred	Amount Under Benchmark	Amount Under Tolerance Band	Shareholder Award w/out 1.5% Cost Cap	1.5% (Annual Gas Commodity) Cost Cap
$2,322,409,536	$2,282,982,247	$2,263,268,602	$2,086,136,231	$196,846,016	$177,132,371	$35,426,474	$26,629,484

PG&E's Core Gas Supply Year 30 Monthly CPIM Summary, provided in Table II below, summarizes monthly gas costs, benchmarks, tolerance limits, and resulting performance relative to the Benchmark. Appendix A, which is submitted to Cal Advocates and the Energy Division on a confidential basis as described in the accompanying declaration, dated July 22, 2025, contains detailed monthly cost information upon which Table II, the Monthly CPIM Summary, is based.

TABLE II
CORE GAS SUPPLY
CUMULATIVE MONTHLY CPIM YEAR 30 REPORT
NOVEMBER 1, 2022 – OCTOBER 31, 2023

	CANADIAN AND U.S. GAS COSTS				PIPELINE RESERVATION CHARGES		TOTAL CPIM PERFORMANCE				TOLERANCE BAND		
Month/Year	Actuals	Benchmark	Benchmark - Actuals	Actuals % of Benchmark	Actuals	Benchmark	Actuals	Benchmark	Benchmark - Actuals	Actuals % of Benchmark	Upper Limit	Lower Limit	(Over)/Under Tolerance
Nov-22	$211,431,900	$218,200,082	$6,768,182	96.9%	$27,734,831	$27,759,401	$239,166,732	$245,959,483	$6,792,752	97.2%	$250,323,485	$243,777,483	$4,610,751
Dec-22	$566,411,116	$576,992,154	$10,581,038	98.2%	$33,714,090	$33,738,660	$600,125,206	$610,730,814	$10,605,608	98.3%	$622,270,657	$604,960,892	$4,835,686
Jan-23	$348,186,200	$484,410,550	$136,224,349	71.9%	$33,858,593	$33,879,440	$382,044,794	$518,289,990	$136,245,196	73.7%	$527,978,201	$513,445,884	$131,401,091
Feb-23	$217,908,837	$242,555,090	$24,646,253	89.8%	$29,855,694	$29,876,541	$247,764,532	$272,431,631	$24,667,100	90.9%	$277,282,733	$270,006,080	$22,241,549
Mar-23	$172,696,302	$164,506,412	($8,189,891)	105.0%	$22,721,575	$23,332,927	$195,417,877	$187,839,339	($7,578,538)	104.0%	$191,129,467	$186,194,275	($4,288,410)
Apr-23	$80,370,527	$78,927,985	($1,442,543)	101.8%	$22,047,285	$22,058,569	$102,417,812	$100,986,553	($1,431,259)	101.4%	$102,565,113	$100,197,274	Within
May-23	$47,518,060	$43,479,795	($4,038,266)	109.3%	$23,433,020	$23,444,303	$70,951,080	$66,924,098	($4,026,982)	106.0%	$67,793,694	$66,489,300	($3,157,386)
Jun-23	$29,533,252	$30,400,775	$867,523	97.1%	$23,710,649	$23,721,933	$53,243,902	$54,122,708	$878,806	98.4%	$54,730,723	$53,818,700	$574,799
Jul-23	$16,968,512	$25,521,524	$8,553,011	66.5%	$23,522,682	$23,533,788	$40,491,194	$49,055,311	$8,564,117	82.5%	$49,565,742	$48,800,096	$8,308,902
Aug-23	$19,169,669	$33,006,340	$13,836,672	58.1%	$23,459,495	$23,470,601	$42,629,163	$56,476,941	$13,847,777	75.5%	$57,137,068	$56,146,877	$13,517,714
Sep-23	$25,558,173	$34,078,393	$8,520,219	75.0%	$23,397,762	$23,408,868	$48,955,936	$57,487,261	$8,531,325	85.2%	$58,168,829	$57,146,477	$8,190,541
Oct-23	$39,546,359	$39,285,366	($260,993)	100.7%	$23,381,645	$23,392,751	$62,928,004	$62,678,117	($249,887)	100.4%	$63,463,825	$62,285,264	Within
Total	$1,775,298,910	$1,971,364,464	$196,065,554	90.1%	$310,837,321	$311,617,783	$2,086,136,231	$2,282,982,247	$196,846,016	91.4%	$2,322,409,536	$2,263,268,602	$177,132,371
												Shareholder Earnings/(Loss)	$26,629,484

5. How the Standard Benchmark Is Determined

The CPIM standard benchmark is composed of five components:

1) Fixed transportation costs, which include Canadian, U.S. interstate, and California intrastate capacity reservation costs;

2) Variable costs, which include natural gas commodity costs, plus pipeline fuel and volumetric transportation costs on Canadian, U.S. interstate, and California intrastate pipelines;

3) Storage costs, which include both the fixed reservation charges and variable costs;

4) Hedging costs, which include 80% of net realized gains or losses and associated transaction costs of PG&E’s winter hedges for its core portfolio; and

5) United States Customs and Border Protection’s Merchandise Processing Fee (MPF).

The total benchmark, composed of fixed and variable costs, is compared to total gas costs,[10] transportation costs, storage costs, and net winter hedging costs for the

[10] Gas costs may include gas processing fees that are associated with a given supply basin. For example, gas purchased in the Rockies region is subject to additional processing fees from Williams Field Services.

applicable CPIM period. The specific benchmark components are further described below.

a. Fixed Transportation Component

The fixed transportation component of the benchmark is composed of capacity reservation costs associated with PG&E's firm capacity holdings on the following pipeline systems:

1. TC Energy Corporation:
   a. NOVA Gas Transmission Ltd. (NGTL);
   b. Foothills Pipe Lines, Ltd. (Foothills);
   c. Gas Transmission Northwest Corporation (GTN);
2. El Paso Natural Gas Company L.L.C. (EPNG);
3. Ruby Pipeline, L.L.C. (Ruby); and
4. PG&E's California Gas Transmission.

The daily contract quantities for each pipeline are shown in Table III of this report.

Revenue from the release of unused capacity is credited against actual costs.

Effective April 1, 2012, pursuant to the CTA Settlement Agreement[11] and as detailed in PG&E Gas Schedule G-CT – Core Gas Aggregation Service, CTAs are required to make elections three times each year to acquire or reject their pro-rata share of pipeline capacity. Under the CTA Settlement Agreement, CTAs assume 100% cost responsibility for their share of pipeline capacity. In addition, CTAs receive an annual allocation of core firm storage inventory, and associated injection and withdrawal rights, adjusted once at mid-year. The costs of Canadian, interstate and intrastate pipeline capacity and firm storage capacity accepted by CTAs, and any costs for rejected capacity for which CTAs are responsible to pay, are not included in the CPIM Benchmark or actual costs. Those costs are paid directly by CTAs, as provided by PG&E's Schedule G-CT. However, any CTA rejected pipeline capacity that remains unallocated after the capacity release auction is deemed to have received a bid for the reservation rate of one penny per dekatherm (Dth) per month ($0.01/Dth/month) by PG&E's CGS Department, and the $0.01/Dth/month is included in both the CPIM Benchmark and actual costs.

b. Variable Cost Component

The variable cost component of the benchmark represents the cost of gas, including fuel and volumetric transportation charges from the supply regions, delivered to PG&E's Citygate (a virtual trading point where PG&E's backbone transmission system connects to the local transmission and distribution system).

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11 The CTA Settlement Agreement, dated August 20, 2010, was approved in the Gas Accord V Decision (D.11-04-031) and constitutes Appendix B of that Decision.

The benchmark is based upon the forecasted level of daily demand, adjusted for any operational imbalance and a monthly allocation of storage injection or withdrawal amounts[12] as described below in Section 5.c. The storage-adjusted demand is allocated among the various transportation paths available to the core gas portfolio based on an established sequence of supply acquisition.[13] The allocated amounts are then multiplied by the appropriate gas cost index, netted forward to PG&E Citygate, and associated with the specific transportation path. The total forms a daily commodity benchmark. The daily benchmark amounts are summed to establish the annual benchmark.

c. Storage Cost Component

PG&E's Gas Schedule G-CFS – Core Firm Storage provides the rate and operational details of the firm storage service for PG&E's core gas portfolio. The CPIM Benchmark includes a monthly storage reservation cost at the tariff rate. The storage cost component was first described in Appendix B of D.97-08-055 and was subsequently modified by the Cal Advocates–PG&E Stipulation as approved in D.04-01-047. The benchmark reflects storage reservation costs for annual inventory, summer injection, and winter withdrawal capacity,[14] all adjusted to remove capacity used by CTAs or which is released on their behalf through the

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12 Operational imbalance and storage profile can be adjusted by any imbalance transactions per PG&E Gas Schedule G-BAL.

13 The gas cost use to develop the sequence is net forward to a PG&E Citygate location price.

14 Injection and withdrawal capacity amount is derived using the formula on Sheet 2 of G-CFS.

procedures in PG&E Gas Schedule G-CT.[15] The CPIM Benchmark demand profile is adjusted by the daily benchmark allocations of injection and withdrawal quantities as agreed to by PG&E and Cal Advocates.[16]

The CPIM MOU associated with D.19-09-025 established a CPIM Benchmark demand profile for Cycling ISP Storage and Residual PG&E Core Storage—which are adjusted by the daily benchmark allocations of injection and withdrawal quantities (storage profile).[17]

Since the CPIM assumes that the withdrawal season starts with a full storage field, the first month of the withdrawal season's storage profile is adjusted for any amount less than full, and the end of the prior injection season's storage profile is adjusted to account for the storage inventory being less than full. Adjustments due to the CTA mid-year storage allocation are also applied to the storage profile.

Pursuant to the Natural Gas Storage Strategy approved via D.19-09-025, PG&E owned natural gas storage capacities were reduced. As such, PG&E firm core gas storage inventory decreased. To fulfill the winter reliability standard per.

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15 See Footnote 12.

16 The injection and withdrawal allocations were established by agreement between PG&E and Cal Advocates and are described in Appendix A of PG&E's Annual CPIM Year 5 Performance Report and modified as per agreement between PG&E and Cal Advocates on October 19, 2009, which is provided as Appendix B in the CPIM Year 16 report, effective CPIM Year 17 and all subsequent CPIM years.

17 The CPIM MOU between PG&E CGS and the Cal Advocates (AL 4271-G) further modifies the injection and withdrawal allocations as described in Footnote 15, in order to conform to the D.19-09-025 storage portfolio.

D.06-07-010, the Commission approved CGS' request to add firm gas storage from independent storage providers (ISP).

d. Hedging Cost Component

The winter hedging cost component of the benchmark contains 80% of the net realized gains or losses and associated transaction costs of the winter hedging transactions, which settled during the period covered by this CPIM report.[18]

e. United States Customs and Border Protection's Merchandise Processing Fee (MPF)

The United States Customs and Border Protection's (CBP) Merchandise Processing Fee (MPF) component of the benchmark is to capture the daily MPF associated with Canadian natural gas purchases.

6. <u>Canadian and US Pipeline Capacity Holdings</u>

As shown in Table III of this report, PG&E holds Canadian, U.S. interstate, and California intrastate capacity for PG&E's core gas customers. PG&E is authorized to recover the costs associated with its Canadian and U.S. interstate capacity through approval procedures specified in D.04-09-022. All approved capacity costs are recovered from PG&E's core gas customers through the Core Pipeline Demand Charge Account, as described in Preliminary Statement Part AE.

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18 OP 1 of D.10-01-023 approved a Settlement Agreement which allowed hedging costs to be recorded in CPIM.

PG&E's CGS is allocated firm intrastate capacity according to PG&E's latest GT&S proceeding and is authorized to recover such costs from its customers.[19]

Pipeline and storage capacity contracts for the core portfolio are subject to change to conform to regulatory requirements and in response to fluctuating market conditions.

Table III below shows all interstate and intrastate pipeline contract quantities and the capacity utilization for each contract during CPIM Year 30.

19 PG&E's Gas Accord III, D.04-12-050, OP 1, approved and adopted all rates and services. In D.07-09-045 (Gas Accord IV) and D.11-04-031 (Gas Accord V), the Commission extended the recovery of core gas procurement, storage and transportation costs.

TABLE III
PIPELINE ASSETS AND UTILIZATION EFFECTIVE
NOVEMBER 1, 2022 – OCTOBER 31, 2023

PG&E Core Gas Supply – Interstate and Canadian Pipeline Assets and Utilization

(Effective During CPIM Year 30)

Line No.		Pipeline	Capacity Dth/d)[1]	Expiration Date	Approx. % Utilization[2]
1	NGTL (3)		287,745	10/31/2027	
2			82,223	10/31/2027	
3		Total NGTL	369,968		93.0%
4	Foothills (3)		284,810	10/31/2027	
5			81,384	10/31/2027	
6		Total Foothills	366,194		93.1%
7	GTN		279,968	10/31/2027	
8			80,000	10/31/2027	
9		Total GTN	359,968		96.9%
10	El Paso				
11		Seasonal (Nov.-Mar.)	162,000	03/31/2023	65.9%
12	Ruby		250,000	10/31/2026	91.8%

PG&E CORE GAS SUPPLY – INTRASTATE PIPELINE ASSETS AND UTILIZATION

Line No.	Pipeline	Capacity Dth/d)[1]	Approx. % Utilization[2]
1	PG&E's California Gas Transmission	–	–
2	Redwood Path	–	–
3	Annual	605,088	–
4	Seasonal (Nov. – Jan.)	250,000	–
5	Seasonal (Nov. – Mar.)	100,000	–
6	Total Redwood	Varies	98.6%
7	Baja Path	–	–
8	Seasonal (Dec. – Feb.)	300,000	88.1%

7. Efforts to Provide Benefits and Protect Core Customers

As noted in Section 2, the CPIM provides incentives for PG&E to proactively lower core gas costs through physical and financial transactions. As described in Section 1 and Section 4, PG&E obtained gas cost savings for its core customers by optimizing its gas purchases and effectively managing its assets while maintaining a high degree of supply reliability. The activities included: (1) optimizing pipeline capacity and selling gas after meeting core demands; (2) using storage when gas demand or prices were high; and (3) balancing supplies with customer demand to avoid imbalance noncompliance charges.

Natural gas liquids extraction revenues are credited against gas costs under the CPIM, with no adjustment to benchmark dollars.[20] In CPIM Year 30, PG&E earned revenue from its contract to supply feed gas for natural gas liquids extraction associated with deliveries on the TC Energy Corporation – NGTL system. Details are provided in confidential Appendix A.

In addition to physical gas management activities described above, PG&E employed (1) a winter hedging strategy to protect core customers from potential extreme gas costs during the peak winter months when core demand is typically the highest, (2) financial hedges to manage pipeline capacity not needed to serve load or inject gas into storage, and (3) financial hedges to manage storage inventory originally intended to be withdrawn during winter but not withdrawn due to low cash-market prices and/or lower than expected winter demand leaving supplies in storage inventory and avoiding reinjection of higher cost gas in the months following. The benefits of financial hedging transactions to manage pipeline capacity and storage inventory are included in the gas costs recorded under the CPIM but have no impact on the CPIM benchmark.

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20 See Footnote 1, CPIM Supplemental Report, Section VI "Additional Features." Part A – Gas Sales/Capacity Brokering Revenue.

8. Conclusion

PG&E's annual CPIM performance report concludes that PG&E's core gas costs, as measured against the aggregate CPIM Benchmark during the period November 1, 2022 through October 31, 2023 (CPIM Year 30), are below the CPIM Benchmark by $196,846,016. The total recorded gas costs should be deemed reasonable and recoverable from PG&E's core customers. In accordance with the incentive award formula and the shareholder award cap, PG&E has earned a shareholder award of $26,629,484. Upon independent verification from Cal Advocates, PG&E will submit an advice letter request to the Commission seeking authorization to recover any award (if applicable).

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

CPIM PERFORMANCE REPORT MONTHLY DETAIL

NOVEMBER 1, 2022 – OCTOBER 31, 2023

FOR CPIM YEAR 30

CONFIDENTIAL IN ITS ENTIRETY,

AS DESCRIBED IN THE ACCOMPANYING DECLARATION

DATED JULY 22, 2025