STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

FILED
09/13/23
01:26 PM
A2106021

September 13, 2023

Agenda ID #21866
Alternate to Agenda ID #21865
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 21-06-021:

Enclosed are the proposed decision of Administrative Law Judges Regina DeAngelis and John Larsen, the designated presiding officers in this proceeding, and the alternate proposed decision of the assigned Commissioner John Reynolds.

An Oral Argument will be scheduled for these items on October 18, 2023. These items may be heard, at the earliest, at the Commission's November 2, 2023 Business Meeting. Until and unless the Commission hears and votes on these items, the proposed decision or the alternate proposed decision have no legal effect.

Public Utilities (Pub. Util.) Code § 311(e) requires that the alternate item be accompanied by a digest that clearly explains the substantive revisions to the proposed decision. The digest of the alternate proposed decision is attached.

This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Upon the request of any Commissioner, a Ratesetting Deliberative Meeting (RDM) may be held. If that occurs, the Commission will prepare and publish an agenda for the RDM three days beforehand. When an RDM is held, there is a related *ex parte* communications prohibition period. (*See* Rule 8.2(c)(4) of the Commission's Rules of Practice and Procedure (Rules).)

When the Commission acts on these agenda items, it may adopt all or part of the decision as written, amend or modify, or set aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision and alternate decision as provided in Pub. Util. Code §§ 311(d) and 311(e) and in Article 14 of the Commission's Rules of Practice and Procedure, accessible on the Commission's website at www.cpuc.ca.gov. Pursuant to Rule 14.3, as modified by the presiding officers, opening comments shall not exceed 40 pages and parties are requested to file one set of comments, addressing both the proposed decision and the alternate proposed decision in a single filing. Comments must be filed pursuant to Rule 1.13 and served in accordance with Rules 1.9 and 1.10. Electronic copies of comments should be sent to assigned Commissioner John Reynolds' advisor Maria Sotero, at maria.sotero@cpuc.ca.gov. The current service list for this proceeding is available on the Commission's website at www.cpuc.ca.gov.

/s/ MICHELLE COOKE
Michelle Cooke
Acting Chief Administrative Law Judge

MLC:nd3
Attachment

Agenda ID #21866
Alternate to Agenda ID #21865
Ratesetting

DIGEST OF DIFFERENCES BETWEEN
THE PROPOSED DECISION OF ADMINISTRATIVE LAW JUDGES
DEANGELIS AND LARSEN, AND THE ALTERNATE PROPOSED DECISION
OF COMMISSIONER JOHN REYNOLDS
APPLICATION 21-06-021 PG&E TY 2023 GENERAL RATE CASE

Pursuant to Public Utilities Code Section 311(e), this is the digest of the substantive differences between the Proposed Decision of Administrative Law Judges DeAngelis and Larsen (mailed on September 13, 2023) and the Alternate Proposed Decision of assigned Commissioner John Reynolds (also mailed on September 13, 2023).

The Alternate Proposed Decision of Commissioner Reynolds differs from the Proposed Decision of Administrative Law Judges DeAngelis and Larsen in treatment of Wildfire System Hardening and Escalation.

The Proposed Decision of Administrative Law Judges DeAngelis and Larsen adopts Wildfire System Hardening of undergrounding 200 miles and installing covered conductor on 1,800 miles at forecasted capital expenditures of $2.105 billion (2023-2026) and adopts PG&E's Update Testimony (PG&E Ex-33) for Escalation, which adjusts for inflation the revenue requirements for 2023-2026. The Proposed Decision results in a $13.820 billion authorized test year revenue requirement in 2023 and post-test year revenue requirements of $14.472 billion in 2024, $14.729 billion in 2025, and $14.851 billion in 2026.

The Alternate Proposed Decision of assigned Commissioner Reynolds adopts a hybrid approach for Wildfire System Hardening of undergrounding 973 miles and installing covered conductor on 1,027 miles at forecasted capital expenditures of $4.270 billion for (2023-2026). Regarding Escalation, Commissioner John Reynolds' Alternate Proposed Decision adopts 25% of the requested adjustments associated with PG&E's Update Testimony (PG&E Ex-33). The Alternate Proposed Decision of assigned Commissioner John Reynolds results in a $13.313 billion authorized test year revenue requirement in 2023 and post-test year revenue requirements of $14.016 billion in 2024, $14.318 billion in 2025, and $14.494 billion in 2026.

ATTACHMENT

Decision **ALTERNATE PROPOSED DECISION OF COMMISSIONER JOHN REYNOLDS**
(Mailed 9/13/2023)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2023. (U39M)	Application 21-06-021

DECISION ON TEST YEAR 2023 GENERAL RATE CASE FOR PACIFIC GAS AND ELECTRIC COMPANY

TABLE OF CONTENTS

DECISION ON TEST YEAR 2023 GENERAL RATE CASE FOR PACIFIC GAS AND ELECTRIC COMPANY

Summary

This decision approves ratepayer funds for Pacific Gas and Electric Company (PG&E) to reinvest in its infrastructure and improve operations to provide safer, cleaner, and more reliable energy for its 16 million customers across Northern and Central California. A complex landscape of critical imperatives drives the approved increased costs, including: mitigating the risk of catastrophic wildfire, improving reliability, preparing the grid for increases in customer load growth and new connections, and safety and reliability improvements for PG&E's extensive gas storage, transmission, and distribution systems. Inflation is also a key driver for the cost increases we approve here, as PG&E's proposed costs due to inflation and other escalation above 2020 approach $4 billion dollars in 2023. These rate increases for essential energy services come at a time when customers are facing economic pressures that already strain their livelihoods, as well as climate change-driven weather events that drive increases in their need for energy. At the same time, California is striving to recover from the impacts of a global pandemic. The Commission reviews PG&E's and other intervenors' proposals with a careful eye toward balancing customer affordability and investments needed to maintain safety and reliability.

This decision directs PG&E to make critical investments in hardening its system against wildfire risk, as well as vegetation management and electric distribution system upgrades. PG&E is directed to invest approximately $4.27 billion in system hardening, including undergrounding and installing covered conductor, and approximately $1.311 billion in vegetation management

to reduce wildfire ignition risk on its electrical system. This decision also directs PG&E to upgrade its distribution capacity system and invest over $2.5 billion from 2023-2026 to be ready to serve higher customer load and new connections to its system. The Commission also approves critical capital increases in other areas of PG&E's operations, such as Gas Operations (Section 3).

Additionally, this decision provides enhanced oversight of PG&E's work and spending on key safety areas. For system hardening, this decision requires heightened reporting for PG&E to demonstrate its progress towards achieving risk reduction and forecasted unit costs, in addition to requiring that costs be recorded in a balancing account. For the pole replacement program, this decision requires PG&E to provide data regarding outage levels and the useful lives of the equipment being replaced to support future programs impacting system reliability, including this one, to support increased oversight of the utility's management of that program. The Commission also adopts a framework to promote transparency and monitor accountability, as reflected in the continuation of the Deferred Work Settlement (Section 2.)

This decision authorizes PG&E to collect from customers $13.313 billion as its 2023 general rate case Track 1 test year revenue requirement, with two adjustments described below. This decision also authorizes PG&E to collect from customers additional amounts for its Track 1 post-test year revenue requirement for 2024 of $14.016 billion (+ 5.3% or $702 million over 2023), 2025 of $14.318 billion (+ 2.2% or $302 million over 2024), and 2026 of $14.494 billion (+ 1.2% or $177 million over 2025). The authorized test year 2023 revenue requirement represents a 9.0% increase over PG&E's 2022 authorized revenue requirement of approximately $12.214 billion, as adopted by the Commission in PG&E's 2020 general rate case, Decision (D.) 20-12-005. Appendix A contains the detailed Results of Operations tables for Track 1 (Sections 3-14) that summarize the revenue requirements for the four-year rate period, 2023-2026.

This decision also adopts a settlement in Track 2 of this proceeding (Section 15) that results in a total revenue requirement increase of $221.233 million to be recovered over 2023 and 2024. Appendix B contains Track 2 Results of Operations.

In addition, this decision concludes that costs recorded in certain memorandum accounts that the Commission has not yet reviewed for reasonableness should be removed from PG&E's authorized revenue requirement and estimates the amount to be $950.612 million for 2023 through 2026 (Section 16). Appendix C contains the details of the adjustments to the revenue requirement due to the determination that these costs are to be removed from PG&E's revenue requirement until such time as the Commission finds these costs reasonable. For the purposes of this decision, the Commission finds it reasonable to implement the removal of these memorandum account amounts for 2023 by subtracting the associated $249.958 million revenue requirement estimate from the total 2023 revenue requirement and reduce the attrition year revenue requirements by subtracting $239.398 million for 2024, $235.115 million for 2025, and $226.141 million for 2026. These numbers are subject to revision as final numbers become known, and the Commission directs PG&E to update this figure forthwith.

This decision also adopts reduced costs in the area of employee financial incentives and denies PG&E's requested 67.79% increases (Section 8.3). More cost reductions are reflected in the Commission's denial of PG&E's request for $385 million to support the replacement of Gas Advanced Metering Infrastructure (AMI) Modules (Section 6).

The Commission also adopts a framework to promote transparency and monitor accountability, as reflected in the continuation of the Deferred Work Settlement (Section 2.)

This decision authorizes significant costs at a time when customers face weighty economic pressures. To balance customer affordability concerns within PG&E's forecasted financial requirements, the Commission scrutinized PG&E's cost requests and found it reasonable to remove approximately $2.932 billion from PG&E's four-year requested increase of $5.212 billion. Based on the evidence, this reduced amount will continue to support and also improve the safety and reliability of PG&E's gas and electric infrastructure and services. Today's decision also provides PG&E a reasonable opportunity to earn its authorized rate of return of 7.28% (2023) in D.22-12-031, as amended.

Pursuant to Commission's Rate Case Plan for large energy utilities, the Commission will consider in a separate proceeding how to distribute the authorized revenue requirement among customer classes. Notably, the amounts authorized today by the Commission do not represent the full amount that PG&E is authorized to collect in revenue requirement for the costs of its operations and services. This decision does not address, for example, recorded expenditures tracked in most of PG&E's Wildfire Mitigation Plan Memorandum Account and other similar accounts because costs tracked in memorandum accounts first require the Commission to engage in a reasonableness review of such costs before PG&E may incorporate those costs into revenue requirement. The revenue requirement authorized in this decision also does not include the following: commodity costs of electricity procured for customers or costs of fuel used in generating PG&E-owned generation that are the subject of separate proceedings, referred to as Energy Resource Recovery Account (ERRA) proceedings. The Commission authorized PG&E to recover $4.227 billion in energy procurement expense in PG&E's most recent ERRA proceeding, D.22-12-044.

This decision authorizes PG&E to implement the test-year 2023 revenue requirement in rates beginning January 1, 2024. In consideration of the impact on customers of the related bill increases, the Commission finds it reasonable to amortize incremental revenue increases, beginning January 1, 2024 to December 31, 2026.

This proceeding remains open.

1. Background

Pacific Gas and Electric Company (PG&E) is an investor-owned regulated public utility providing natural gas and electric service to approximately 16 million people in California through approximately 5.4 million electric accounts and 4.3 million natural gas customer accounts. Its service territory consists of approximately 70,000 square-miles in northern and central California stretching from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada mountains in the east.[1] PG&E's electric distribution system is comprised of approximately 106,681 circuit miles of electric distribution lines and 18,466 circuit miles of interconnected transmission lines; its gas distribution system is comprised of approximately 42,141 miles of natural gas distribution pipelines and 6,438 miles of transmission pipelines.

Every four years, the California Public Utilities Commission (Commission) requires the large energy utilities, including PG&E, to file an application in a

[1] Decision (D.) 20-12-005, Decision Addressing the Test Year 2020 General Rate Case of Pacific Gas and Electric Company (December 3, 2020) at 14-15.

general rate case (GRC) proceeding.[2] The purpose of this GRC proceeding is to review and determine the revenues that are necessary and required, referred to as the revenue requirement, for that four year period, with the first year referred to as the test year and the subsequent years referred to as attrition years (or post-test years) for the utility to meet its service obligations. For PG&E, these responsibilities include providing safe, reliable, affordable, and clean gas and electric service at the lowest just and reasonable rates in support of fulfilling fundamental and essential public health and safety necessities along with meeting economic needs and desires while promoting economic prosperity. With input from parties, the Commission reviews PG&E's application in a formal GRC proceeding and conducts an in-depth examination of PG&E's needed investments and expenses forecast for the test year. These include forecasts of capital investments; Operations and Maintenance (O&M) expenses; Administrative and General (A&G) expenses; federal, state, and local taxes; depreciation; and other costs.[3] The result is a determination of the revenue requirement for the test year and whether that justifies a modification from the previously authorized amount. The examination also includes a forecast of the necessary revenues for the three remaining years (attrition years) in the four-year GRC cycle. Finally, the examination may also consider other changes in PG&E's future operations.

In this proceeding, which is PG&E's GRC for 2023-2026, PG&E seeks authority from the Commission to adopt a test year revenue requirement for

[2] D.20-01-002, Decision Modifying the Commission's Rate Case Plan for Energy Utilities (January 16, 2020).

[3] PG&E's electric rates include other additional costs, such as the costs for fuel and purchased power. These additional costs are not addressed here but in separate, specific proceedings focused solely on those costs.

2023 of $16.174 billion.[4] This is an increase of $3.967 billion (29.5%) over the $12.214 billion authorized for 2022. PG&E also requests additional base revenue requirement increases of $1.069 billion (6.6%) in 2024, $850 million (4.9%) in 2025, and $668 million (4.0%).[5] Over the four years, the total requested increase in revenue requirement is $6.554 billion (53.7%) over the 2022 authorized revenue requirement in PG&E's 2020 GRC of $12.214 billion in 2022.[6]

The amounts summarized above reflect several items addressed in this decision and modifications to PG&E's request over the course of the proceeding. First, these amounts include the results in an unopposed settlement regarding Wildfire Liability Insurance (filed by motion on October 7, 2022). This settlement reduced PG&E's 2023 test year request by $307 million and continues to reduce the anticipated revenue requirement in the attrition years, 2024-2026. Second, the amounts also reflect the results of a stipulation regarding disputed forecasts for PG&E's Energy Supply; Enterprise Data Management and Information Technology; and Administrative and General Expenses. Third, the amounts include PG&E's revised proposals for System Hardening, i.e., electrical assets undergrounding and installing covered conductor, in High Fire-Threat Districts (HFTD).[7] PG&E's initial June 30, 2021 cost forecast included a proposal to underground approximately 200 miles from 2023 to 2026.[8] In PG&E's Application, as amended, PG&E increased this cost proposal to reflect

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[4] PG&E Reply Brief at Appendix A, A-1; PG&E Ex-33 at 4-AtchA2.

[5] PG&E Ex-64 (JCE) at 1-2; PG&E Application at 2. PG&E Ex-33, Ch. 4, the amounts include the escalation adjustment set for in PG&E's September 6, 2022 Update Testimony.

[6] PG&E Opening Brief at 857; PG&E Ex-33 at 4-AtchA-2.

[7] PG&E Reply Brief at 9-10.

[8] PG&E Ex-04; PG&E Ex-17 (Rebuttal).

undergrounding over 3,000 miles of distribution assets in PG&E's HFTDs.[9] Subsequently, PG&E reduced its cost forecast for undergrounding distribution assets to include approximately 2,000 miles for the 2023-2026 period, and PG&E's final request totaling approximately $5.9 billion, as amended in its December 9, 2022 Reply Brief, is the cost forecast the Commission considers in this proceeding.[10]

1.1. Procedural History

On June 30, 2021, PG&E filed its 2023 GRC Application. PG&E requests authority to increase rates effective January 1, 2023 for its electric and gas customers through 2026.[11] PG&E also requests authority to recover certain costs tracked in various memorandum and balancing accounts, continue some accounts, discontinue other accounts, and create two new accounts.

Protests to the Application were timely filed by: Citadel Energy Marketing LLC and Tourmaline Oil Marketing Corp. (Citadel and Tourmaline); Lodi Gas Storage LLC (Lodi), Wild Goose Storage LLC (Wild Goose), and Central Valley Gas Storage LLC; Aera Energy LLC, Chevron U.S.A. Inc., PBF Energy Inc., Phillips 66 Company, and Tesoro Refining & Marketing Company LLC (collectively, Indicated Shippers); California Farm Bureau Federation (Farm Bureau); the Public Advocates Office at the California Public Utilities Commission (Cal Advocates); Mussey Grade Road Alliance (MGRA); Pioneer Community Energy, Marin Clean Energy, City and County of San Francisco, East

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[9] PG&E Application, as amended March 10, 2022, at 5 to 6 (PG&E's revised Testimony is dated February 25, 2022).

[10] PG&E Reply Brief at 9. These amounts are calculated using the escalation factors in PG&E Ex-33 September 6, 2022 Update Testimony.

[11] All documents filed in PG&E's Application proceeding are available on the Commission's website at the *Docket Card* for this proceeding, A.21-06-021.

Bay Community Energy, Peninsula Clean Energy Authority, San Jose Clean Energy, Sonoma Clean Power Authority, Silicon Valley Clean Energy Authority (collectively, Joint CCAs); The Utility Reform Network (TURN); Northern California Generation Coalition; Southern California Generation Coalition and City of Palo Alto, California (jointly, SCGC/PA); California Large Energy Consumers Association (CLECA); and Energy Producers and Users Coalition (EPUC).

Responses were timely filed by: Small Business Utility Advocates (SBUA); Southern California Edison Company (SCE); National Diversity Coalition (NDC); Peninsula Corridor Joint Powers Board (Caltrain); Southern California Gas Company (SoCalGas); San Diego Gas & Electric Company (SDG&E); Gill Ranch Storage LLC (Gill Ranch); and the Coalition of Utility Employees.

Motions for party status were granted for: FEITA Bureau of Excellence LLC; AARP; Engineers and Scientists of California, Local 20, International Federation of Professional & Technical Engineers (ESC); California Trout Inc., Friends of the Eel River, and Trout Unlimited (collectively, Cal Trout); Center for Accessible Technology (CforAT); Calpine Corporation (Calpine); California Community Choice Association (CCCA); Microsoft Corporation (Microsoft); Wild Tree Foundation; Pacific Coast Federation of Fishermen's Associations (PCFFA); and Institute for Fisheries Resources (IFR).

On July 16, 2021, PG&E filed a motion for a Commission order to make the revenue requirement authorized for 2023 effective January 1, 2023, even if the decision authorizing the 2023 revenue requirement is issued after that date. The motion also requested that the adopted revenue requirement include interest, based on a Federal Reserve three-month commercial paper rate. In addition, PG&E requested approval of three memorandum accounts.

On July 26, 2021, TURN moved for reassignment on preemptory challenge of the assigned Administrative Law Judge (ALJ), pursuant to Rule 9.2 of the Commission's Rules of Practice and Procedure (Rules). On August 5, 2021, the motion was granted and a new ALJ assigned.

On August 16, 2021, PG&E replied to the protests and responses to the Application.

On August 30, 2021, a prehearing conference (PHC) was held to identify parties and discuss the scope of issues, categorization, schedule of the proceeding, and other procedural matters. The PHC was held virtually due to guidance from the California Department of Public Health concerning restrictions on public gatherings to protect public health and slow the spread of COVID-19.

On October 1, 2021, the assigned Commissioner issued a Scoping Memo and Ruling (Scoping Memo) setting forth the issues, need for hearing, schedule, category, and other necessary matters to scope the proceeding. The Scoping Memo divided the schedule into two tracks. Track 1 was to review the reasonableness of the majority of matters in this proceeding, including the 2023 test year revenue requirement; adjustment mechanisms for attrition years 2024, 2025, and 2026; and safety, environmental and social justice issues. Track 2 was the reasonableness review of recorded costs for 2019, 2020, and 2021 in memorandum and balancing accounts and, to the extent relevant, safety, environmental and social justice issues. A possible Track 3 was also identified that would address the reasonableness of 2022 recorded costs in memorandum and balancing accounts. The Scoping Memo stated that phase 3 would be added in an Amended Scoping Memo, if needed.

The Scoping Memo also addressed nine matters raised in protests, motions, and requests. The Scoping Memo denied TURN's August 5, 2021 motion seeking an order requiring PG&E to supplement its GRC proposal with an alternative spending plan limiting the growth in proposed spending to the rate of inflation. The Scoping Memo also ordered PG&E to present additional evidence including: (1) 2021 recorded expenditures to be submitted by March 31, 2022, (2) revisions to the forecasted expenditures for electrical undergrounding programs, (3) an analysis applying the affordability metrics set forth in D.20-07-032.[12]

On March 1, 2022, March 10, 2022, and March 22, 2022, Public Participation Hearings (PPHs) were held at 2:00 p.m. and 6:00 p.m., for a total of six PPHs. These PPHs were conducted by audio and video, and archived on the Commission's website. Statements were taken from approximately 159 persons over the course of these six hearings. The information provided by the public to the Commission during these PPHs is presented in more detail below.

On March 10, 2022, PG&E filed an amended Application to revise PG&E's System Hardening forecasts, including its significant changes in its forecast for undergrounding electric distribution assets, other wildfire mitigation measures, such as vegetation management, and added its Enhanced Powerline Safety

[12] D.20-07-032, Decision Adopting Metrics and Methodologies for Assessing the Relative Affordability of Utility Service (July 16, 2020).

Setting (EPSS) program.[13] Testimony in support of PG&E's amended Application was submitted on February 25, 2022.[14]

On April 12, 2022, the ALJs denied motions to limit discovery. The ALJs also revised the proceeding schedule in response to issues raised by the parties regarding the need for additional time to review PG&E's February 25, 2022 revised testimony on System Hardening and modified proposal for undergrounding distribution assets.

On April 21, 2022, protests to the amended Application were filed by three parties: California Broadband & Video Association (CalBroadband);[15]AT&T California (AT&T); and Comcast Cable Communications Management LLC (Comcast).

On April 28, 2022, the ALJs denied a motion by Wild Goose and Lodi to compel PG&E to produce confidential gas storage cost data. The ruling specifically did not limit parties or the Commission from considering costs to expand the Independent Storage Providers' (ISP) existing storage compared to PG&E's costs to retain the Los Medanos Storage Facility.

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[13] PG&E Application at 1 and 6 (as amended on March 10, 2022). The new EPSS program seeks to instantaneously de-energize lines in high fire risk areas "when vegetation or other debris contact is detected on overhead powerlines, which significantly reduces the risk of an ignition due to contact with our [PG&E] equipment."

[14] The October 1, 2021 *Assigned Commission's Scoping Memo and Ruling* at 14 set a deadline of February 2022 for PG&E to file any revised testimony regarding modifications to its System Hardening (undergrounding) proposal to reflect its then-recent public announcement to underground 10,000 miles of infrastructure. PG&E timely submitted its revised testimony on February 25, 2022. No deadline was set for PG&E to file an amended Application. PG&E filed its Amended Application on March 10, 2022, after it submitted its revised testimony.

[15] The protest was filed by California Cable & Telecommunications Association (CCTA). By pleading filed on March 13, 2023, CCTA notified the Commission and the service list that its name was changed in February 2023 to California Broadband & Video Association.

On May 2, 2022, PG&E replied to the protests to its March 10, 2022 amended Application.

On June 23, 2022, the Commission issued D.22-06-033 granting PG&E's request for a January 1, 2023, effective date for test year 2023 revenue requirement, with appropriate interest. It also authorized PG&E to use three existing memorandum accounts to track any over-collection or under-collection in rates.[16]

On August 15, 2022, virtual evidentiary hearings began. On September 6, 2022, PG&E served its Update Testimony to reflect changes in inflation and tax changes, as permitted by the Commission's Rate Case Plan.[17] The Commission held a total of 12 days of evidentiary hearings on PG&E's request presented in this proceeding, including evidentiary hearings on PG&E September 6, 2022 Update Testimony. Evidentiary Hearings concluded on September 23, 2022.[18]

On October 7, 2022, PG&E, TURN, and Cal Advocates filed an unopposed joint motion for expedited approval and adoption of a proposed settlement on Wildfire Liability Insurance.

By ruling on November 1, 2022, parties were granted an extension of time to file briefs on depreciation, with those more limited opening briefs due November 10, 2022, and reply briefs due December 15, 2022.

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[16] D.22-06-033, Decision Granting Pacific Gas and Electric Company's Request for a January 1, 2023 Effective Date for the Test Year 2023 Authorized Revenue Requirement (June 23, 2022).

[17] D.20-01-002, *Decision Modifying the Commission's Rate Case Plan for Energy Utilities* (January 16, 2020). PG&E Ex-33 (adjustments to escalation rates).

[18] The testimony of witnesses during the evidentiary hearings were transcribed by a court reporter and the transcripts are available on the Commission's website at the *Docket Card* for this proceeding, A.21-06-021.

On November 4, 2022, opening briefs on all but depreciation issues were filed by PG&E, Cal Advocates, jointly SCE/SoCalGas/SDG&E, TURN,[19] the Coalition of Utility Employees, Joint CCAs, SBUA, AT&T, Wild Tree Foundation, jointly SCGC/PA, Farm Bureau, Cal Trout, CalBroadband, jointly Wild Goose/Lodi, MGRA, and ESC.

On November 10, 2022, opening briefs on Depreciation issues were filed by PG&E, Cal Advocates, Indicated Shippers, and TURN.

On December 9, 2022, reply briefs were filed on all but Depreciation issues by Cal Advocates, TURN, AT&T, jointly SCGC/PA, AARP, SCE, SBUA, Joint CCAs, Coalition of Utility Employees, jointly SoCalGas/SDG&E, CalBroadband, MGRA, and jointly Wild Goose/Lodi.

On December 12, 2022, PG&E filed its reply brief on all but Depreciation issues (accepted as a late filing by ruling dated December 12, 2022).

On December 15, 2022, reply briefs on Depreciation issues were filed by: PG&E, Cal Advocates, TURN, and Indicated Shippers.

On January 6, 2023, a joint motion was filed by PG&E and Cal Advocates for approval of a Settlement Agreement on Track 2 issues.

On January 12, 2023, the Commission in D.23-01-005 granted the joint motion for adoption of the unopposed settlement on Wildfire Liability Insurance.[20] The decision approved revenues of $400 million in 2023 for such coverage consisting entirely of self-insurance for third-party wildfire claims of

[19] TURN filed an Amended Opening Brief on November 8, 2022.

[20] D.23-01-005, Decision Approving Settlement Regarding Wildfire Liability Insurance Coverage (January 12, 2023).

less than $1 billion per year within the framework of the California Wildfire Fund.[21]

By ALJ ruling dated January 12, 2023, a motion was granted for parties to file limited sur-reply briefs for the limited purpose of addressing PG&E's further revisions to its undergrounding proposal presented in PG&E's December 9, 2023 reply brief. PG&E's December 9, 2022 revised undergrounding cost forecast is addressed at Section 4, herein.

On January 20, 2023, the ALJs issued a ruling adopting a protective order and results of operations and rates modeling procedures to assure the confidentiality of the Commission's decision-making and deliberative process.

On January 23, 2023, limited sur-reply briefs on the topic of PG&E's December 9, 2022 revised undergrounding cost forecast were filed by Cal Advocates, AT&T, CalBroadband, Farm Bureau, TURN, and Coalition of Utility Employees.

On February 6, 2023, comments were filed by Caltrain on the proposed settlement of Track 2 issues.

Also on February 6, 2023, PG&E moved for an order to establish Track 3. PG&E states that the purpose would be to examine the reasonableness of 2022 recorded costs in the same memorandum and balancing accounts under review through 2021 in Track 2, plus the review of 2022 recorded costs in three additional accounts.

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[21] In 2019, legislation established a new wildfire insurance fund to facilitate payment of wildfire-related liabilities, allowed electric utilities to elect to participate in the fund, instituted other requirements for utilities to access the fund, specified procedural mechanisms for utilities to seek recovery of costs, and limited ratepayer costs. D.23-01-005, *Decision Approving Settlement Regarding Wildfire Liability Insurance Coverage* (January 17, 2023) at 7-9.

On February 21, 2023, PG&E filed a reply to Caltrain's February 6, 2023 comments on the proposed Track 2 settlement.

By ALJ ruling dated April 25, 2023, PG&E's motion to establish Track 3 in this proceeding was denied on the grounds that the addition of a Track 3 would unreasonably expand the extensive record and extend the already long duration of this proceeding. The ALJ ruling noted that PG&E could file a separate application for review of its 2022 recorded costs.

On May 9, 2023 and June 23, 2023, the ALJs issued rulings moving several exhibits into evidence.

On July 3, 2023, the ALJs issued a ruling taking official notice of three relevant documents.

On August 3, 2023, TURN filed a motion requesting the Commission to take additional evidence into the record pertaining to capital revenue requirements recorded in wildfire risk mitigation memorandums accounts prematurely included in PG&E's requested revenue requirement for 2023-2026. In response, the ALJs issued a ruling directing PG&E to file a response with further information on the topics raised by TURN. On August 18, 2023, PG&E filed its response to the ALJ Ruling. The Commission addresses PG&E's August 18, 2023 response at Section 16, herein.

The Commission adopts the rulings of the ALJs in this proceeding.

On August 18, 2023, the record was closed and submitted for Commission decision.

1.2. Public Comments and Public Participation Hearings

The Commission held six virtual PPHs that targeted areas throughout PG&E's service territory and accessible to all customers. The purpose of these

PPHs was to listen to and to solicit comments from PG&E's customers regarding PG&E's general rate Application and proposed rate increases. The PPHs were conducted by the assigned ALJs, and each of the five Commissioners attended at least one PPH.[22]

During each PPH, informational and educational materials were provided about the Application, including estimated bill impacts for an average residential electric and gas customer. An explanation was also given of the Commission's procedures for processing the Application and the taking of public comments. Customer service representatives from PG&E were present at the PPHs to answer individual customer billing and service questions.

Almost all PG&E customers who spoke at the PPHs opposed PG&E's proposed rate increases. Most asserted that the proposed increases are unreasonable, based on PG&E's history of mismanagement, and are not affordable, especially for people with low incomes and fixed incomes, such as the elderly, the retired, and members of California's vulnerable populations.

Many speakers voiced concerns over PG&E's poor gas and wildfire safety record and PG&E's history of delayed maintenance of critical infrastructure. These speakers requested metrics and increased transparency of PG&E's operations and accounting to ensure that PG&E spends money on safety appropriately. Speakers sought metrics to account for how money is disbursed. Instead of increasing rates, speakers commented that PG&E should find alternative ways to cut expenses, including curtailing bonuses and other high compensation to executives and shareholders. Speakers commented that PG&E

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[22] The comments provided by the public during these PPHs were transcribed by a court reporter and a copy of the transcript is available on the Commission's website at the *Docket Card* for this proceeding, A.21-06-021.

should be solely accountable for its own mismanagement and should bear the cost of deferred maintenance because of evidence that PG&E's inaction contributed to catastrophic wildfires. To avoid rate increases to pay for safety-related expenses, speakers proposed organizational changes, including: (1) having the state take over PG&E; (2) reducing PG&E profit; (3) breaking PG&E into smaller regional companies; and (4) reducing PG&E's monopoly power or increasing competition.

The March 10, 2022 PPHs received comments from public officials in the San Joaquin Valley, including the mayors of Fresno, Bakersfield, Madera, and many other local officials. Their comments included information regarding the constraints on the electrical infrastructure in the Madera area. Similar comments were made by officials of the city of Rio Dell in Humboldt County.

In addition to the comments at the PPHs, the Commission received over 2600 written comments, letters, and emails from customers and other members of the public. In written comments, customers expressed concerns similar to those presented at the PPHs, such as the unaffordability of PG&E's proposed rate increase, PG&E's poor safety and maintenance history, and the need for increased transparency of PG&E's operations and spending. Much of this written correspondence can be found on the Commission's webpage at the Docket Card for this proceeding.[23]

1.3. Affordability of Utility Rates

The Commission has a statutory obligation to limit a utility's recovery of its costs to those that are just, reasonable, and necessary for the provision of safe

[23] The written public comments are available for review on the Commission's website at the *Docket Card* for this proceeding, A21-06-021, at the tab for *Public Comment.*

and reliable service.[24] The Commission has emphasized that "a key element of finding a charge or rate is just and reasonable is whether that charge or rate is affordable."[25] Particularly regarding low-income ratepayers, the law states:

> recognizing that electricity is a basic necessity, and that all residents of the state should be able to afford essential electricity and gas supplies, the commission shall ensure that low-income ratepayers are not jeopardized or overburdened by monthly energy expenditures.[26]

Further, the Commission:

> shall ensure that rates are sufficient… to recover a just and reasonable amount of revenue… while observing the principle that electricity and gas services are necessities, for which a low affordable rate is desirable.[27]

In July 2018, the Commission initiated a proceeding to establish a framework and principles to identify and define affordability criteria for use in the setting of just and reasonable utility rates.[28] In 2020, the Commission adopted affordability metrics, along with a definition of affordability as "the degree to which a representative household is able to pay for an essential utility service, given its socioeconomic status."[29] Although the Commission is still assessing the

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[24] Public Utilities Code (Pub. Util. Code) Sections 451 and 454(a).

[25] D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company (May 16, 2019) at 11.

[26] Pub. Util. Code Section 382(b).

[27] Pub. Util. Code Section 739(d)(2).

[28] R.18-07-006, Order Instituting Rulemaking to Establish a Framework and Processes for Assessing the Affordability of Utility Service (July 12, 2018).

[29] D.20-07-032, Decision Adopting Metrics and Methodologies for Assessing the Relative Affordability of Utility Service (July 16, 2020) at 2, 9, and Conclusion of Law 6.

specific application of affordability metrics in ratesetting proceedings, the Commission has committed to begin considering them in GRCs.[30]

After revising its request several times during this proceeding, including in updated testimony on February 25, 2022, updated escalation rates on September 6, 2022, and on December 9, 2022 in its reply brief, PG&E is now requesting a revenue requirement of $15.819 billion for 2023, an increase of approximately 29.5% over the 2022 adopted revenue requirement of $12.214 billion.[31] This makes affordability a central issue in this proceeding. On this issue, PG&E provided evidence[32] that included metrics for the Affordability Ratio[33] and the Hours at Minimum Wage.[34] TURN and Cal Advocates recommend that such metrics only support limited rate increases, and offer specific proposals for taking these metrics into consideration.

TURN cites affordability metrics that are broken out by climate zone based on both California Alternate Rates for Energy (CARE) and non-CARE rates.[35] On average, according to TURN, customers with affordability ratio scores of 20 are already paying more than 13% of disposable income for gas and electricity across PG&E's service territory. TURN states that this is projected to increase to 14.70% in 2023 without any increased usage for PG&E's utility services. In the hottest

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[30] D.20-07-032, Decision Adopting Metrics and Methodologies for Assessing the Relative Affordability of Utility Service (July 16, 2020) at 37.

[31] PG&E Reply Brief at Appendix A, A-1.

[32] PG&E Opening Brief at 9-11.

[33] D.20-07-032 at 2, notes that the Affordability Ratio is the ratio of essential utility service charges to non-disposable household income.

[34] D.20-07-032 at 11, notes that the Hours at Minimum Wage metric seeks to describe the hours of work necessary for a household earning minimum wage to pay for essential utility service charges.

[35] TURN Opening Brief at 8.

climate zones, TURN asserts that customers will face monthly bills of more than 24% of disposable income. With the CARE discount, PG&E's services, according to TURN, will cost on average 11.3% of CARE customers' disposable income (an increase of 1.8%), for the same level of usage, and CARE customers living in the hottest climate zones are expected to pay up to 16.5% of their disposable income for gas and electricity.[36]

To address the short- and long-term threats to affordability, TURN makes two recommendations. First, TURN recommends that the Commission use the risk spend efficiency (RSE) data PG&E was required to present in this GRC to reduce spending that provides insufficient risk reduction benefits for the cost incurred. Second, TURN urges the Commission to limit PG&E's authorized spending growth by the rate of inflation.[37]

PG&E objects to TURN's recommendations and other claims that PG&E is not adequately taking affordability metrics into consideration. PG&E states that it has provided all the information required by the Commission, it fully supports the Commission's affordability framework proceeding, and that the affordability proceeding has yet to determine how affordability metrics should be taken into consideration in GRCs.[38]

PG&E states that its approach to addressing affordability is to help customers through programs already available to assist customers in paying their utility bills, including CARE, the Family Electric Rate Assistance Program (FERA), and the Energy Savings Assistance (ESA) energy efficiency program.[39]

[36] TURN Opening Brief at 11.

[37] TURN Opening Brief at 17-29.

[38] PG&E Reply Brief at 21-23.

[39] PG&E Opening Brief at 7-9.

PG&E states that approximately 27% of its residential customers are enrolled in either CARE or FERA.[40] In addition, PG&E describes how other programs help customers who are still struggling to pay their bills despite programs like CARE, FERA, and ESA.[41] According to PG&E, these include the Commission adopted Arrearage Management Plan (AMP),[42] and Percentage of Income Payment Plan (PIPP) pilot,[43] as well as the Low Income Home Energy Assistance Program (LIHEAP) administered by another California state agency. Several parties criticize PG&E's strategy of offering customer assistance programs as a solution to the affordability crisis in California.[44] Although expanding these programs will provide some assistance to Californians struggling to pay their utility bills, TURN and others state that they by no means solve the present utility service affordability crisis.

The Commission will consider affordability here using the available policy, metrics, and record developed in this proceeding to scrutinize and allow only those investments and costs that are just and reasonable, and disallow those that provide minimal benefit from a safety and reliability perspective.[45]

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[40] PG&E Opening Brief at 8.

[41] TURN Opening Brief at 15.

[42] AMP is a year-long program that allows customers to receive forgiveness of 1/12 of their past due bill after each on-time payment of their current monthly charges (up to $8,000).

[43] PIPP is a pilot program adopted in D.21-10-012 but not yet implemented. The pilot will cap an eligible customer's monthly bill at a fixed percentage of their income. For example, under the pilot, customers in the lowest income level would receive a monthly electric bill capped at a maximum of $29 and a monthly gas bill capped at a maximum of $9.

[44] PG&E Reply Brief at 25.

[45] D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company (May 16, 2019) at 18-19.

1.4. Legal Principles

This Section provides an overview of legal principles involved in determining PG&E's authorized revenue requirement.

1.4.1. Burden of Proof

Pub. Util. Code Section 451 provides that "all charges demanded or received by any public utility … shall be just and reasonable." Pursuant to Pub. Util. Code Section 454(a):

> A public utility shall not change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified.

It is well-established that an applicant, such as PG&E, must meet the burden of proving that it is entitled to the relief it is seeking. PG&E has the burden of affirmatively establishing the reasonableness of all aspects of its Application.[46]

Although the utility bears the ultimate burden to prove the reasonableness of the relief it seeks and the costs it seeks to recover, the Commission has held that when other parties propose a different result, they too have a "burden of going forward" to produce evidence to support their position and raise a reasonable doubt as to the utility's request.[47]

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[46] D.21-08-036, Decision on Test Year 2021 General Rate Case for Southern California Edison Company (August 19, 2021) at 9, citing to D.09-03-025, Alternate Decision of President Peevey on Test Year 2009 General Rate Case for Southern California Edison Company (March 13, 2009) at 8; D.06-05-016, Opinion on Southern California Edison Company's Test Year 2006 General Rate Increase Request (May 11, 2006) at 7.

[47] D.21-08-036, *Decision on Test Year 2021 General Rate Case for Southern California Edison Company* (August 19, 2021) at 10; D.20-07-038 at 3-4; D.87-12-067 at 25-26, 1987 Cal. PUC LEXIS 424, *37.

1.4.2. Standard of Proof

The standard of proof applicants must meet in rate cases is preponderance of the evidence.[48] Preponderance of the evidence usually is defined "in terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.'"[49] To meet their burden, applicants must clearly delineate in their GRC filings how their forecasted costs are just, reasonable and necessary, as well as being separate and distinct from the costs they are presently, or in the future, tracking in balancing and memorandum accounts.[50]

When the necessity of PG&E's actions is called into question, the Commission may in some circumstances apply the prudent manager standard. Under the prudent manager standard, the Commission does not evaluate reasonableness based on hindsight but based on what the utility knew or should have known at the time it made its decision.[51] This standard reaches not just the

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[48] D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company (May 16, 2019) at 7; D.15-11-021, Decision on Test Year 2015 General Rate Case for Southern California Edison Company (November 5, 2015) at 8-9; D.14-08-032, Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2014-2016 (August 14, 2014) at 17.

[49] D.08-12-058, Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project (December 18, 2008) at 19, citing to Witkin, Calif. Evidence, 4th Edition, Vol. 1 at 184.

[50] *See*, D.23-02-017, *Decision Approving Settlement* (February 2, 2023) at 26, providing that "Going forward we expect electric corporations to clearly delineate in their GRCs how their forecasted costs are separate and distinct, including labor and overhead, from the costs they are presently, or in the future, tracking in wildfire related memorandum accounts and to make a similar showing in any application for which they seek recovery of recorded costs, including a catastrophic wildfire proceeding."

[51] D.22-06-032, Decision Addressing Southern California Edison Company's Track 3 Request for Recovery of Wildfire Mitigation Memorandum and Balancing Account Balances (June 23, 2022) at 18.

activities and associated costs for which PG&E seeks recovery here but extends to the actions or inactions that resulted in those activities being necessary.[52]

As part of this proceeding, settlement agreements may be approved by the Commission under Rule 12.1 of the Rules of Practice and Procedure only if they are reasonable in light of the whole record, consistent with the law, and in the public interest. Proponents of a settlement agreement have the burden of proof and must demonstrate that the proposed settlement meets the requirements of Rule 12.1. Only upon meeting those requirements is a settlement agreement eligible for adoption by the Commission.[53]

1.5. Utility Ratemaking – The General Rate Case

This Section provides an overview of ratemaking principles used in determining PG&E's authorized revenue requirement for the topics addressed herein for years 2023, 2024, 2025, and 2026.

This GRC proceeding examines and determines PG&E's authority to recover through rates the reasonable costs of capital investments and annual expenses necessary to operate and maintain its facilities and equipment in a safe and reliable manner. To do so, PG&E's Application provides detailed forecasts of its capital investments and annual expenses for the 2023 test year, as well as forecasts for the three subsequent years, or attrition years.[54]

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[52] TURN Opening Brief at 40; D.18-07-025, Order Denying Rehearing of Decision (D.) 17-11-033 (July 12, 2018) at 3, 5, 6 (citing to D.87-06-021); D.21-11-036, Order Modifying Decision 19-09-025 and Denying Rehearing of Decision 19-09-025, as Modified (November 19, 2021) at 15.

[53] D.12-10-019, Order Denying Rehearing of Decision (D.) 08-08-030 (October 11, 2012) at 14-15; D.09-11-008, Decision Denying Motion to Adopt Contested Settlement and Dismissing Application (November 20, 2009) at 6.

[54] D.20-01-002, Decision Modifying the Commission's Rate Case Plan for Energy Utilities (January 16, 2020) at 8.

The Commission has reviewed and considered all exhibits, the evidentiary hearing transcripts, briefings, and all arguments raised by the parties in deciding each element of the revenue requirements and related policy directives adopted in this decision even if not specifically mentioned. The Commission uses that record in reaching and explaining the decisions on each relevant issue later addressed herein.

This rate case presents challenges. Among these is balancing potentially necessary cost and rate increases with affordability. PG&E, for example, proposes rate increases to pay what PG&E believes are necessary investments and expenses to reduce wildfire risk, further the State's clean-energy public policy, and account for inflation.[55] At the same time, TURN, Cal Advocates, and other parties emphasize the necessity of considering the utility service affordability crisis.

To address affordability concerns, TURN contends the Commission should authorize spending growth by PG&E consistent with the rate of inflation.[56] According to TURN, "Current forecasts project that PG&E's residential average rates will be 60% higher by 2025 than if they had been growing at the rate of inflation since 2013."[57] PG&E objects to constraining its expenditures by the rate

55 PG&E Opening Brief at 15.

56 TURN Opening Brief at 3-17. While the Commission denied TURN's August 5, 2021 request to require PG&E to submit an alternative inflation-constrained budget. TURN argues in its Opening Brief at 17 that the Commission should adopt a revenue requirement that constraints increases passed on to customers by the rate of inflation.

57 TURN Opening Brief at 5.

of inflation, arguing that this violates provisions of the regulatory compact[58] and denies PG&E the opportunity to recover its actual costs of service.[59]

Although the Commission continues to support the goal of PG&E reducing expenses, the Commission understands both the legal requirement to allow recovery of all just and reasonable costs (whether above or below the rate of inflation), and PG&E's need for additional safety programs (even if that undercuts PG&E's ability to reduce overall costs in this rate case cycle). Since TURN's proposals also involve Commission requirements and policy related to affordability, risk mitigation, and post-test year ratemaking, these arguments are introduced here and discussed more specifically in the relevant Sections, herein.

For its part, since this request involves deferred work and other principles regarding Commission-authorized work, this request is considered in the context of the issues related to deferred work principles discussed below. PG&E maintains that it already fully considers and reaches the right balance among safety, reliability, and cost. Other parties disagree and assert that many of PG&E's proposed activities are unreasonable.[60] At the very least, they contend that PG&E must apply risk management factors adopted by the Commission that

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[58] D.20-01-002 at 10-11, provides that the regulatory compact "is viewed as a contract between the utility's investors and its customers; as such, it establishes rights, obligations, and benefits for both sides of the bargain." (D.20-01-002 at 10.) It involves the utility's investors having an obligation to provide safe, reliable, and adequate service to all customers in the utility's service area, with the service sold at rates that recover reasonable costs and which are at sufficient levels to allow investors access to and recovery of capital, all while facing no (or limited) competition from other sellers. In exchange, the customers get rates and terms of service set by the state's regulatory entity that are just and reasonable, non-discriminatory, and without preference in quantity or quality. That is, the utility charges just and reasonable rates; provides just, equitable, and reasonable service; and has the opportunity to recover its actual, legitimate, and prudent costs plus a fair return on the capital investments made to provide that service.

[59] PG&E Opening Brief at 15.

[60] TURN Opening Brief at 21-24; Cal Advocates Opening Brief at 19.

consider the relative costs and benefits of PG&E's risk mitigation programs. Risk spend efficiency and other risk management tools are discussed elsewhere in the decision.

PG&E requests that the Commission adopt both its estimating method and results of operations model (RO model) to calculate its 2023 revenue requirement. According to PG&E, its estimating method gathers data on operating expenses and capital components for the Commission jurisdictional functions using an Unbundled Cost Category (UCC) format that supports a full summary of earnings for each UCC. PG&E states that its RO model has been used in all PG&E GRCs since 2007 and two Gas Transmission and Storage (GT&S) cases. PG&E also states that its RO model maintains the UCC organization to compute revenue requirements that can be summarized to electric and gas distribution, electric generation, and GT&S functions.

PG&E provided information on the RO model in Appendix D to its November 4, 2022 opening brief. The RO model compiles expense and capital expenditure forecasts and calculates the revenue requirement based on the following standard cost of service ratemaking formula:

$$RRQ = E + D + T + (r \times RB)$$

"RRQ" is the revenue requirement;

"E" is all operating and maintenance expenses, administrative and general expenses, and taxes other than income;

"D" is book depreciation expense;

"T" is income taxes paid to federal and state governments;

"r" is the allowed return on rate base; it is a direct input obtained from a Cost of Capital proceeding;[61] and

"RB" is the total used and useful capital investment in plant and equipment dedicated to providing utility service.[62]

In this proceeding, PG&E presents its cost forecasts at the Major Work Category (MWC) level for O&M expenses and capital expenditures. For PG&E's Electric Distribution, Gas Distribution, and GT&S lines of business, the MWC forecasts are further broken down into Maintenance Activity Types (MAT) code levels. Administrative & General costs include corporate services organization costs and companywide expenses. These costs are input into the RO model by department (such as Finance or Human Resources), or by cost type (such as medical, dental, or property insurance).[63] Based on the cost-of-service ratemaking formula, PG&E receives a rate of return on its rate base. PG&E's current rate of return is 7.27% and this decision does not change that rate of return.[64]

[61] A.22-04-008, Application of Pacific Gas and Electric Company for Authority to Establish Its Authorized Cost of Capital for Utility Operations for 2023 and to Reset the Cost of Capital Adjustment Mechanism (U39M) (April 20, 2022); D.22-12-031, Decision Addressing Test Year 2023 Cost of Capital for Pacific Gas and Electric Company, Southern California Edison, Southern California Gas Company, and San Diego Gas & Electric Company (December 15, 2022). Commission regulation does not guarantee utilities will earn either the authorized rate of return (ROR), or return on equity (ROE), that are adopted and used by the Commission in setting just and reasonable rates. Rather, a utility's actual or recorded ROR or ROE may be higher or lower than what the Commission used in setting rates depending on how the utility manages its costs. If the utility's actual costs end up lower (higher) than the costs adopted in the authorized revenue requirement, then its recorded ROR could be higher (lower) than the authorized ROR, and the earned ROE might be higher (lower) than that used in setting authorized rates.

[62] PG&E Opening Brief, Appendix D at D-40.

[63] PG&E Opening Brief at 18.

[64] D.22-12-031, Decision Addressing Test Year 2023 Cost of Capital for Pacific Gas and Electric Company, Southern California Edison, Southern California Gas Company, and San Diego Gas & Electric Company (December 15, 2022) at Ordering Paragraph (OP) 1.

1.5.1. Use of Recorded and Forecasted Costs

Given the complexity of GRCs, the Commission has a Rate Case Plan to expedite the processing of these proceedings. The plan includes defining the scope of the data to be considered.[65] Ideally, all relevant evidence is filed with the utility's application, thereby allowing timely, thorough, and transparent review by all parties. Consistent with its plan, the Commission only allows amendments or updates to applications under certain circumstances, in order to reduce the complexity of, and delays in, processing the rate case application.[66] Intervening parties often seek to use most the recent data available. A GRC, however, cannot be completed on time if data is constantly updated.

PG&E submitted recorded data for 2020 with its Application because, consistent with the Commission's Rate Case Plan, the "base year" in this rate case is 2020, which was the test year of PG&E's previous GRC.[67] The test year in this proceeding is 2023. PG&E states that it developed its 2023 test year forecast using recorded 2020 data and a forecast of 2021 and 2022 capital expenditures. PG&E further states that its forecast "excludes 2021 recorded costs and is based on information that was known or available when PG&E's forecast was developed in March 2021 in accordance with the Rate Case Plan.[68] According to

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[65] D.89-01-040, Opinion (January 27, 1989); D.93-07-030; D.07-07-004, Opinion Modifying Energy Rate Case Plan (July 12, 2007); D.20-01-002, Decision Modifying the Commission's Rate Case Plan for Energy Utilities (January 16, 2020).

[66] For example, in D.93-07-030, the Commission only permitted an update of certain marginal cost and revenue data.

[67] D.20-12-005, Decision Addressing the Test Year 2020 General Rate Case of Pacific Gas and Electric Company (December 3, 2020).

[68] PG&E Opening Brief at 283.

PG&E, "this was the best data available to PG&E at the time it prepared its general rate case and is consistent with the requirements of the Rate Case Plan."[69]

At the request of intervenors, the Commission required PG&E to file recorded data for the next year (2021) by March 2022 and PG&E provided this data.[70] However, in the Scoping Memo, the assigned Commissioner did not require this more current data, such as the 2021 recorded data, to be used by PG&E or any of the parties.[71] In opposition to various forecasts discussed below, Cal Advocates asserts that the Commission should use a partial or full year of 2021 recorded data.[72] In response, PG&E argues that the Commission should consistently use either the 2021 forecasts, the 2021 recorded data, or the 2020 recorded data but should not use a partial year of 2021 recorded data.[73]

In 2019, the Commission reiterated that more recent data may be more accurate. However, it is not feasible to constantly update all data in a GRC.[74] In some instances, it may be reasonable to apply updated data and, overall, the Commission will continue to use the 2020 base year data, consistent with the Rate Case Plan.

[69] PG&E Opening Brief at 18-19; D.07-07-004, App. A at A-32, Item B, "recorded data, …, shall be provided for at least the latest recorded year available at the time of tendering the Notice of Intent."

[70] PG&E Reply Brief at 33.

[71] October 1, 2021 Assigned Commissioner's Scoping Memo and Ruling at 5, 6, and 14.

[72] Cal Advocates Reply Brief at 8-10; PG&E Opening Brief at 294.

[73] PG&E Opening Brief at 18-20.

[74] D.19-09-051, Decision Addressing the Test Year 2019 General Rate Cases of San Diego Gas & Electric Company and Southern California Gas Company (September 26, 2019) at 59-60.

1.5.2. Uncontested Expense Forecasts and Capital Expenditure Requests

PG&E requests the Commission approve expense forecasts and capital expenditure costs for hundreds of different programs, many of which are uncontested. Appendix A of PG&E's Opening Brief includes four tables that list the uncontested forecasts: (1) expense programs by MWC or MAT; (2) capital programs by MWC or MAT; (3) department costs; and (4) companywide expenses. Overall, PG&E suggests that approximately 34% of PG&E's expense forecast, 17% of PG&E's capital forecasts, 59% of PG&E's forecast for department costs, and 9% of PG&E's companywide expense forecast are uncontested.[75]

As a general matter with respect to individual uncontested issues in this proceeding, the Commission finds that PG&E has made a *prima facie* showing that the test year estimates and other amounts are just and reasonable. The Commission adopts these undisputed amounts, unless discussed otherwise below.

1.5.3. Stipulations

Parties continued their discussions, even after evidentiary hearings, to narrow the issues in dispute. As a result, certain groups of parties were able to reach stipulations on forecasts for the following topics: (1) Energy Supply (most disputed issues); (2) Shared Services and Information Technology (Enterprise Records and Information Management and Data Governance only); and (3) Administrative and General Expenses (all disputed issues). The stipulations are in the record as appendices to PG&E's Opening Brief: Appendix E (Energy Supply), Appendix F (Information Technology), and Appendix G (A&G). The

[75] PG&E Opening Brief at 21.

Commission adopts them as discussed briefly in the relevant decision Sections, herein.

In addition, parties filed motions in this proceeding requesting the Commission approve settlements of certain disputed issues. The Commission adopted a settlement in D.23-01-005 to approve a proposed settlement regarding PG&E's wildfire liability insurance costs. In addition, certain parties filed a motion for approval of a settlement of issues pertaining to costs tracked in certain balancing accounts and memorandum accounts. The Commission addresses this settlement at Section 15, herein.

1.5.4. Accounting Codes

GRCs are complex and take a long time to process.[76] In D.20-01-002, the Commission requested that energy utilities suggest an approach that would enable it and parties to easily compare costs in GRC applications across utilities.[77] PG&E submitted its Application in this proceeding using its own, unique MWC and MAT internal accounting system.[78] In support, PG&E states that the Commission considered and declined in D.20-01-002 to adopt an Energy Division staff proposal "to require the utilities to present their GRC request in a format that conforms to the corresponding FERC accounting structure."[79] The

[76] R.13-11-006, Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety Improvements and Revise the General Rate Case Plan for Energy Utilities (November 14, 2013) at 15.

[77] D.20-01-002, Decision Modifying the Commission's Rate Case Plan for Energy Utilities (January 16, 2020) at 69.

[78] PG&E Ex-10 at 1A-2.

[79] D.20-01-002, Decision Modifying the Commission's Rate Case Plan for Energy Utilities (January 16, 2020) at 69; R.13-11-006, Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety Improvements and Revise the General Rate Case Plan for Energy Utilities (November 14, 2013), General Rate Case Plan Workshop #2 Report, GRC Standardization at 11.

Commission also decided against ordering workshops "to consider the use of the FERC's Uniform System of Accounts in the utilities' GRC applications."[80]

Cal Advocates recommends that the Commission order PG&E to host workshops with Energy Division to present the Commission with a common accounting format for recording forecast costs in GRCs, and to do so by December 31, 2024. Cal Advocates states this will improve transparency and efficiency.[81]

Cal Advocates gives several reasons for this recommendation. First, it asserts PG&E's MWC and MAT codes have been inconsistently applied from one cycle to the next as shown by a comparison of MWCs/MATs in the 2023 GRC, 2020 GRC, and 2019 GT&S rate cases. This inconsistency makes it challenging for decision-makers and parties to rely on historic data to assess the reasonableness of future expenses. Second, requiring PG&E to present a common format would likely improve the quality of PG&E's analyses. Third, standardized accounting would allow the Commission to develop a methodology across utilities, so that risk analyses are more specific and comparable.[82]

In this proceeding, the Commission finds instances in which tracking PG&E's historical data to assess the reasonableness of future expenses has been challenging for parties and the Commission. Having a consistent and common accounting system format would improve transparency, efficiency, and the quality of GRC analyses, including the forecasting methodologies. The Commission may consider this issue in the future.

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[80] D.20-01-002, Decision Modifying the Commission's Rate Case Plan for Energy Utilities (January 16, 2020) at Finding of Fact 9 at 76.

[81] Cal Advocates Opening Brief at 28-29.

[82] Cal Advocates Opening Brief at 29-30.

2. Risk Management and Safety

It is well-settled that "One of the central tasks facing the Commission in this proceeding is to balance safety and reliability risks in comparison with cost. [The utility] is required by law to 'promote the safety, health, comfort, and convenience of its patrons, employees, and the public' while including only 'just and reasonable' charges in its rates [*citing to* Pub. Util. Code Section 451]. Our fundamental challenge in many disputed areas of this case is to reach an outcome consistent with these twin objectives. This is a familiar challenge that has been present in countless previous GRCs and other proceedings, even though the approach, framework, and language surrounding the issues continue to evolve."[83]

The Commission's use of risk assessment tools for measuring and reducing risk is the culmination of multiple Commission proceedings, starting in 2013 with the Safety Model Assessment proceeding (S-MAP proceeding) in R.13-11-006. In the S-MAP proceeding, the Commission established a risk-based decision-making framework and methodology for energy utilities set forth in D.14-12-025 to increase transparency and accountability regarding how utilities prioritize and manage risk.[84] This framework includes risk management programs and data-driven tools to be employed by utilities across their enterprises and operations. These tools assist utilities, interested parties, and the

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[83] D.15-11-021, Decision on Test Year 2015 General Rate Case for Southern California Edison Company (November 5, 2015) at 9 (fn. omitted.)

[84] In D.14-12-025, Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan and Modifying Appendix A of Decision 07-07-004 (December 4, 2014) at 32 and 40, the Commission described a key objective of the then-soon-to-be-implemented Risk Assessment and Mitigation Phase (RAMP) proceedings (which are filed before general rate cases) as presenting a prioritization of risk mitigation alternatives, in light of estimated mitigation costs to risk mitigation benefits. These key objectives were presented by Commission staff and are referred to as Refined Straw Proposal in D.14-12-025.

Commission in evaluating how energy utilities assess safety risks and manage and mitigate such risks. Such risk analysis aims to provide information to help understand the cost-effectiveness of programs to improve the safety of utility customers, employees, contractors, and communities.[85]

To further the goals of the S-MAP proceeding, the Commission established two procedures designed to ensure that the large energy utilities include thorough risk assessment and mitigation plans in all future GRC applications in which utilities request general funding, including funding for safety-related activities: (1) an S-MAP application to be filed by each of the large utilities in the S-MAP proceeding;[86] and, (2) a subsequent Risk Assessment and Mitigation Phase (RAMP) report to be filed as a preliminary step before a utility's GRCs.[87] The two purposes of the S-MAP application are: (1) to allow parties to understand the models the utilities propose to use to prioritize programs and projects intended to mitigate risks; and (2) to allow the Commission to establish standards and requirements for those models.[88] The Commission's decisions in S-MAP application proceedings have determined whether particular risk assessment approaches or models can be used for RAMP filings. The risk-based

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[85] D.18-12-014 Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) at 28.

[86] The filing of S-MAP applications by energy utilities was a one-time directive and PG&E complied with this directive on May 15, 2015, when it filed its S-MAP application, which was consolidated as A.15-05-002 *et al*. In contrast, the RAMP filings are required prior to each general rate case filing, every four years.

[87] D.14-12-025, Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan and Modifying Appendix A of Decision 07-07-004 (December 4, 2014).

[88] D.14-12-025 Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan and Modifying Appendix A of Decision 07-07-004 (December 4, 2014); D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) at 5.

decision-making framework fulfills the state policy of ensuring that the Commission and energy utilities prioritize safety[89] and implement safety policy consistent with the principle of just and reasonable rates.

Several years of adjudicating S-MAP and RAMP proceedings led to the approval of the 2020 Safety Model Assessment Settlement Agreement in D.18-12-014 (S-MAP Settlement Agreement).[90] In the S-MAP Settlement Agreement, the Commission standardized risk-based decision-making modeling for utilities to employ in RAMP and GRC filings. The S-MAP Settlement Agreement framework includes the following minimum steps for analyzing risk and mitigations for the RAMP and GRCs:[91]

- Step 1A - Building a Multi-Attribute Value Function (MAVF) model. In this GRC, the risk attributes assessed are safety, electric reliability, gas reliability, and financial loss.
- Step 1B - Identifying Risks for the Enterprise Risk Register (ERR) for purposes of determining which risks will be addressed in RAMP reports.
- Step 2A - Risk Assessment and Risk Ranking in Preparation for filing RAMP reports.
- Step 2B - Selecting Enterprise Risks for RAMP reports.

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[89] Pub. Util. Code Section 963(b)(3) provides that "(b) The Legislature finds and declares all of the following: … (3) It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates."

[90] The Commission's Safety Model Assessment Proceeding A.15-05-002, *et. al.* (a consolidated proceeding involving all large energy utilities) led to the S-MAP Settlement Agreement adopted by the Commission in D.18-12-014, *Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications* (December 13, 2018) at Attachment A.

[91] D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) at 22.

- Step 3- Mitigation Analysis for Risks in RAMP reports that determines the risk reduction from mitigation reflected in Risk Spend Efficiency factors.

As set forth above, the S-MAP Settlement Agreement requires utilities to build an MAVF to uniformly model risk in a way that quantifies the potential risk reduction of an activity together with its cost.[92] As the Commission has previously explained, the MAVF allows utilities to compare different enterprise risk events by positioning the risk scores on a common scale (the MAVF risk unit). In this proceeding, PG&E states that it uses the MAVF to identify top safety, reliability, and financial risks and to evaluate and rank alternative risk mitigation programs.

Recently, in D.22-12-027, the Commission adopted a "Cost-Benefit Approach that includes standardized dollar valuations of Safety, Electric Reliability and Gas Reliability Consequences from Risk Events."[93] Much of the record of this proceeding was complete before that decision was adopted, so we are not fully able to use that framework in today's decision. These principles will

[92] D.15-11-021 *Decision on Test Year 2015 General Rate Case for Southern California Edison Company* (November 5, 2015) at 9, *citing to* D.14-12-25 at 4, stating: "In Decision (D.) 14-12-025, we adopted a new framework for future GRCs to 'assist the utilities, interested parties and the Commission, in evaluating the various proposals that the energy utilities use for assessing their safety risks, and to manage, mitigate, and minimize such risks.' Much of the record of this proceeding was complete before that decision was adopted, so we are not fully able to use that framework. Nevertheless, we review SCE's application with an eye toward balancing cost and risk." *See also* D.16-08-018.

[93] D.22-12-027, Phase II Decision Adopting Modifications To The Risk-Based Decision-Making Framework Adopted In Decision 18-12-014 And Directing Environmental And Social Justice Pilots (December 15, 2022) at 12, stating that the Commission's decision "replaces the MAVF framework — currently used in the RDF to translate different risk Consequences into unitless Risk Scores that can be compared and ranked — with the Cost-Benefit Approach, which expresses risk Consequences in dollar values and provides an indication of the cost-effectiveness of proposed mitigations; …"

apply to PG&E next RAMP application and its 2027 GRC. Nevertheless, we review PG&E's application with an eye toward balancing cost and risk.

TURN disputes PG&E's risk modeling and makes two recommendations. TURN recommends changes to PG&E's MAVF for risk analyses for future proceedings. The Commission finds that TURN's recommendations are more appropriately considered in the S-MAP proceeding.[94] TURN also recommends that the Commission analyze the cost-effectiveness of PG&E's proposals using RSEs and Benefit-Cost (B/C) ratios calculated under either PG&E's MAVF or TURN's proposed MAVF.[95]

On the topic of RSEs, Cal Advocates recommends that the Commission require PG&E to host a technical working group to discuss, analyze, and consider societal impacts when modeling the financial and safety impact of PSPS on customers.[96] As with TURN's recommended changes to PG&E's MAVF, the

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[94] TURN Opening Brief at 91, states "For purposes of future RSE analysis until modified by subsequent CPUC order, PG&E should be required to: (1) use linear scaling functions for its Financial and Safety attributes; and (2) revise its MAVF weights and scales to achieve a statistical value of life (SVL) that is consistent with the Department of Transportation's SVL. For purposes of the Commission's analysis of the cost-effectiveness of PG&E's proposals in this case, the Commission should use RSEs and Benefit-Cost (B/C) ratios calculated under either PG&E's MAVF or TURN's proposed MAVF, in recognition of the fact that the results under either MAVF show that the programs for which TURN supports its recommendations with RSE analysis have low RSEs and B/C ratios."

[95] TURN Opening Brief at 49-52, stating, in part, "Section 2.3.3 [TURN] explains how the RSEs required by the S-MAP Settlement can be readily expressed as Benefit-Cost (B/C) ratios, which augment the usefulness of RSEs by providing a stand-alone measure of cost-effectiveness. PG&E's objections to TURN's expression of RSEs as B/C ratios rely on the incorrect and irrational design of the financial attribute of its multi-attribute value function (MAVF) and should be rejected." The Commission notes that D.22-12-022 adopted a revised the MAVF for future rate cases to a "Cost-Benefit Approach" but that revision does not apply to this PG&E general rate case because the Commission stated in D.22-12-022 at 24, as follows: "We direct the IOUs to implement the Cost-Benefit Approach in their next respective GRC cycles, beginning with PG&E's 2024 RAMP application."

[96] Cal Advocates Opening Brief at 36-40.

Commission finds Cal Advocates' modeling recommendations are more appropriately considered in the S-MAP proceeding.

The S-MAP Settlement Agreement adopted by the Commission requires utilities to divide asset groups associated with risk events into subgroups or tranches with similar characteristics or risk profiles.[97] The division of tranches is to be based on how the risks and assets are managed by the utility, data availability, and model maturity with the goal of striving to achieve as deep a level of granularity as is reasonably possible.[98] This is important because risk reductions from mitigations and risk spend efficiencies are designed to be determined at the level of tranches with homogeneous or similar risk profiles.[99] In accordance with the Commission-adopted S-MAP Settlement Agreement, PG&E provided a ranking of risk mitigations by RSEs, in this proceeding for those mitigations addressed in PG&E's RAMP Application.[100] The Commission has been clear that RSEs are one factor among many that PG&E may use to select its mitigation strategy.[101] In this GRC proceeding, the Commission adopted

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[97] The S-MAP lexicon defines a tranche as "a logical disaggregation of a group of assets (physical or human) or systems into subgroups with like characteristics for purposes of risk assessment." D.18-12-014 at 18. For the purposes of S-MAP analysis, a tranche is considered to have a homogeneous risk profile, including the same likelihood of risk event (LoRE) and consequence of risk event (CoRE). D.18-12-014, *Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications* (December 13, 2018) Attachment A (S-MAP Settlement) at A-11, Element 14.

[98] PG&E Opening Brief at 33; PG&E-15-E at 1-13, *citing to* D.18-12-014, Attachment A, Appendix A, A-11, No. 14.).

[99] PG&E Opening Brief at 33; PG&E-15-E at 1-13, *citing to* D.18-12-014, Attachment A, Appendix A, A-11, No. 14.).

[100] D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) Attachment A, at A-14, No. 26.

[101] D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) Attachment A, at A-14.

S-MAP Settlement Agreement requires PG&E to clearly and transparently explain its rationale for selecting risk mitigations for each risk tranche and, in addition, explain its rationale for the selection of its overall portfolio of risk mitigations.[102] The Commission has acknowledged that risk mitigation selection can be influenced by other factors, beyond just the RSE, including funding, labor resources, technology, planning and construction lead time, compliance requirements, and operational and execution considerations.[103] According to the S-MAP Settlement Agreement, as adopted by the Commission, if PG&E uses other factors in selecting risk mitigations, PG&E must explain whether and how any such factors affected PG&E's ultimate risk mitigation selections.[104]

2.1. Integration of RAMP and RSEs in PG&E's General Rate Case

PG&E states that, in accordance with the S-MAP Settlement Agreement, it identified, modeled, assessed, and ranked risks; selected RAMP and non-RAMP mitigations; calculated RSEs; and ranked risk mitigations by RSEs in its RAMP Report.[105] On June 30, 2020, PG&E filed its RAMP Report in preparation for this GRC.[106] The Commission's Safety Policy Division evaluated PG&E's RAMP Report and, after completing its review, the Safety Policy Division issued its Staff Evaluation Report dated November 25, 2020.

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[102] D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) Attachment A, at A-14.

[103] D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) Attachment A, A-14.

[104] D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) Attachment A, at A-14.

[105] PG&E Ex-02, WP 1-134 to WP 1-911 (PG&Es 2020 RAMP Report).

[106] PG&E Opening Brief at 30.

Safety Policy Division identified deficiencies, gaps, and areas for improvement and PG&E responded in comments dated January 15, 2021, and January 29, 2021.[107] PG&E states that it considered Safety Policy Division's feedback in making its safety-related forecasts in this proceeding.[108] Subsequently, in this proceeding, PG&E provided ranked updated risk mitigations.[109] In this Application, PG&E states that PG&E's enterprise and operation risk management program provides its lines of business with tools, methods, and technical support to "[d]evelop and implement mitigations and controls that have the greatest potential to reduce those risks and are the most cost-effective options, or most compelling RSE, for managing risk."[110] TURN recommends using RSEs as a key tool and the basis for recommending reductions in risk management programs not shown to be cost-effective by their low RSEs or cost-benefit ratios. TURN argues for reductions in certain mitigation programs based partly on their low RSE scores.[111] In response, PG&E states that the S-MAP Settlement Agreement's RSE calculation methodology "is not sufficiently mature to support funding decisions."[112] PG&E states that RSEs should not be the sole factor in determining the reasonableness of PG&E forecasts for risk mitigation programs at issue in this GRC. PG&E contends that TURN's analysis is inconsistent with Commission precedent and that TURN uses RSE scores for a purpose that was never intended. In response, PG&E argues, in

[107] PG&E Opening Brief at 30.

[108] PG&E Opening Brief at 30-31.

[109] PG&E Ex-02 at 1-16 to 1-21.

[110] PGE Ex-02 at 1-5.

[111] TURN Opening Brief at 17.

[112] PG&E Ex-16; TURN Opening Brief at 50 (fn. 146); TURN Opening Brief at 69-72.

general, that risk-based decision-making must include a wide variety of considerations rather than being based on a single summary statistic.[113] PG&E states further that it bases its risk control and risk mitigation programs on a series of prioritization investment decision meetings where proposed programs are evaluated based on contribution to risk reduction, code compliance, and reasonableness.

In this proceeding, the Commission considers RSEs on a case-by-case basis and in a manner consistent with past precedent. The S-MAP Settlement Agreement was a milestone toward achieving a more rigorous, quantitative method of risk assessment and risk prioritization and toward "providing information required to better understand the cost-effectiveness of proposed mitigations."[114] The Commission has determined that "RSE calculations are critical for determining whether utilities are effectively allocating resources to initiatives that provide the greatest risk reduction benefits per dollar spent, thus ensuring responsible use of ratepayer funds,"[115] and that one of the goals of the

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[113] PG&E Opening Brief at 43.

[114] D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) at 44.

[115] D.21-08-036, *Decision on Test Year 2021 General Rate Case for Southern California Edison Company* (August 19, 2021) at 38 (*citing to* Resolution WSD-002 and Resolution WSD-004). "For SCE's proposed wildfire covered conductor program, this includes the presentation of RSE calculations at the circuit level. This direction is consistent with the Commission's Resolutions adopting the 2020 WMPs, which found that 'RSE calculations are critical for determining whether utilities are effectively allocating resources to initiatives that provide the greatest risk reduction benefits per dollar spent, thus ensuring responsible use of ratepayer funds,' and that SCE's '2020 WMP is lacking in this regard.' While we are cognizant that RSEs are not the only factor in the development and consideration of a prudent risk mitigation plan (which may be influenced by other factors, such as labor resources, technology, compliance requirements, planning and construction lead time, etc.), it is SCE's responsibility to clearly and transparently explain its rationale for selecting the type and scale of risk mitigations, including how RSE calculations were considered."

S-MAP Settlement Agreement was to "use risk reduction per dollar spent to prioritize projects."[116]

Nevertheless, as noted above, the Commission has found that a "utility is not bound to select its mitigation strategy based solely on RSE ranking." Mitigations can be influenced by other factors.[117] As a result, the Commission has found that RSEs provide a useful point of comparison regarding the cost-effectiveness of proposed mitigations.[118] The Commission addresses risk mitigations in a more detailed manner, when needed, regarding specific risks and forecasts presented herein.

2.2. Deferred Work and Spending Accountability

The Commission has adopted a Deferred Work Settlement, which requires PG&E to make an explicit and specific showing at the program level when PG&E seeks ratepayer funding for work previously authorized on the basis of safety and reliability but whose completion was deferred to a future rate case cycle. The Deferred Work Settlement recognizes that, because of changes to the risk landscape that can happen after a rate case decision is issued, it is sometimes necessary for PG&E to defer and re-prioritize authorized funding to a different program. In such cases, it requires PG&E to make a showing that such deferral and reprioritization was justified and reasonable. The need for the Deferred Work Settlement arose, because in a series of PG&E GRC decisions in 2007, 2011,

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[116] D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) at 12, 14.

[117] D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) Attachment A, S-MAP Settlement Element 26, at A-14.

[118] D.21-08-036, Decision on Test Year 2021 General Rate Case for Southern California Edison Company (August 19, 2021) at Finding of Fact 32.

and 2014, there was considerable dispute about the reasonableness of deferred work and whether ratepayers should be charged a second time for such work, resulting in extensive discussions in Commission decisions.[119]

Under the Deferred Work Settlement, an affirmative deferred work showing in PG&E's direct testimony is required when all of the following are true:

1. The work was requested and authorized based on representations that it was needed to provide safe or reliable service.
2. PG&E did not perform all of the authorized and funded work as measured by authorized (explicit or imputed) units of work; and
3. PG&E is again requesting funding in the current general rate case cycle to perform this same work.[120]

When these elements apply, D.20-12-005 requires PG&E to show how the specific funding request is consistent with the following six principles for deferred work. These principles constitute a negotiated and agreed upon synthesis of the Commission's previously stated expectations for what is reasonable with regard to deferral of risk reduction work:[121]

1. Where funds are originally collected from ratepayers based on representations that the work is necessary to provide safe reliable service and, yet PG&E does not perform all of the designated work, the fact that PG&E must pay for a higher priority activity or program does not nullify or extinguish its responsibilities to fund forecasted and

[119] TURN Opening Brief at 92-93.

[120] TURN Opening Brief at 93.

[121] D.20-12-005, *Decision Addressing the Test Year 2020 General Rate Case of Pacific Gas and Electric Company* at 324-326; TURN Ex-19, Attachment 1, Deferred Work Settlement Agreement, Section 5.2 at 36-37.

authorized work unless such work is no longer deemed necessary for safe and reliable service.

2. PG&E is responsible for providing safe and reliable customer service whether or not its overall spending matches funding levels authorized or imputed in rates.
3. PG&E bears the risk that, as a result of meeting spending obligations necessary to provide safe and reliable service, the earned rate of return may be less than the authorized return.
4. While PG&E has finite funds to meet capital and operational needs, PG&E is not restricted to spending only up to the forecast adopted in the GRC.
5. PG&E bears the responsibility — and has discretion – to adjust priorities to accommodate changing conditions after test year forecasts are adopted. Readjusting spending priorities, however, only involves the ranking and sequence of spending. Reprioritizing spending for new projects does not automatically justify postponing projects previously deemed necessary for safe and reliable service.
6. The GRC process is a tool in supporting PG&E's ongoing ability to provide safe and reliable service while affording a reasonable opportunity to earn its rate of return and thereby attract capital to fund its infrastructure needs. Adopted revenue requirements and the disposition of disputed ratemaking issues should be consistent with the goal of supporting PG&E's ability to provide safe and reliable service while maintaining its financial health and ability to raise capital.[122]

The Deferred Work Settlement further requires that for any work that meets the deferred work conditions, PG&E's direct showing in support of the reasonableness of our forecast in the rate case explain:

[122] D.20-12-005, *Decision Addressing the Test Year 2020 General Rate Case of Pacific Gas and Electric Company* at 324-326; TURN Ex-19, Attachment 1, Deferred Work Settlement Agreement, Section 5.2 at 36-37.

a. Why the authorized work was not performed in the time forecasted;

b. Whether the deferral of the authorized work resulted in lower than authorized spending for the authorized work;

c. How the funding was reallocated and whether such reallocation related to the provision of safe and reliable service; and

d. To the extent that authorized funding for safety-related work was used for other purposes, the reasonableness of the alternative work for the purpose of evaluating the appropriateness of the new funding request.[123]

The Commission further stated that "to the extent that authorized funding was diverted to alternative work, PG&E must show the reasonableness of this alternative work.[124]

In this proceeding, PG&E states that the Deferred Work Settlement should be discontinued because is no longer necessary to ensure that PG&E is accountable for managing authorized funding because (1) existing Commission decisions and requirements already require PG&E to identify deferred work in rate cases; and (2) extensive annual risk spending accountability reporting requires PG&E to analyze spending and variances from authorized spending over the whole GRC cycle.[125] In addition, PG&E states that it uses an enterprise

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[123] D.20-12-005, *Decision Addressing the Test Year 2020 General Rate Case of Pacific Gas and Electric Company* at 324-326; TURN Ex-19, Attachment 1, Deferred Work Settlement Agreement, Section 5.2 at 36-37. *See also,* PG&E Opening Brief at 58.

[124] D.20-12-005, *Decision Addressing the Test Year 2020 General Rate Case of Pacific Gas and Electric Company* at 324-326; TURN Ex-19, Attachment 1, Deferred Work Settlement Agreement, Section 5.2 at 36-37; TURN Opening Brief at 94.

[125] PG&E Opening Brief at 60-62; PG&E Reply Brief at 62-66.

framework to work with the various PG&E lines of business "to prioritize the work that we feel is most critical in addressing safety and risk at the time."[126]

TURN and Cal Advocates recommend the Commission maintain the Deferred Work Settlement. In addition, TURN recommends that the Deferred Work Settlement be modified to require PG&E to demonstrate that any reprioritization of funds from work meeting the deferred work criteria be supported by RSE scores. Likewise, Cal Advocates supports the continuation of the Deferred Work Settlement and adds that the deferred work principles cannot be applied over a group of deferred work projects but, instead, each principle must be applied on a case-by-case basis to particular work.[127]

The Commission finds that the Deferred Work Settlement continues to provide benefits of transparent and agreed-upon standards against which PG&E's requests can be assessed and to ensure that ratepayers received value for funds already paid. For this reason, the Commission directs PG&E to continue to follow the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC, subject to the limitations of Pub. Util. Code Section 8386.3, which restricts the diversion of revenues authorized for certain wildfire mitigation activities.[128]

3. Gas Operations

This Section reviews PG&E's Gas Operations expense and capital expenditures forecasts for operating and maintaining PG&E's natural gas

[126] PG&E Opening Brief at 55-56.

[127] Cal Advocates Opening Brief at 43-44.

[128] The wildfire mitigation requirements of Assembly Bill 1054 limit this flexibility with regard to wildfire mitigation expense. *See, e.g.*, Pub. Util. Code Section 8386.3(d)(1) ("An electrical corporation shall not divert revenues authorized by the commission to implement the wildfire mitigation plan to any activities or investments outside of the plan.").

transmission, storage, and distribution system from 2023 to 2026. PG&E address this forecast in PG&E Ex-03, Ch. 2.

PG&E's Gas Transmission and Storage system is composed of approximately 6,600 miles of transmission pipeline, 38 compressor units at nine compressor stations, and 456 pressure regulating stations. PG&E owns and operates three gas storage facilities and has an interest in a fourth. PG&E-owned storage facilities include 109 storage wells, 14 miles of transmission pipes, well controls for each injection and withdrawal well, and 3,404 acres of reservoirs with over 52 billion cubic feet of working gas capacity.

PG&E's Gas Distribution system includes distribution mains, gas services, and gas meters to residential, commercial, and industrial customers.[129] PG&E maintains approximately 43,000 miles of distribution mains servicing 4.3 million residential, commercial, and industrial customers.[130] Distribution mains and services include distribution pipelines, risers, pits and vaults, valves, and ancillary services (e.g., cathodic protection). The programs related to the Gas Distribution system include PG&E's Distribution Integrity Management Program (DIMP), distribution pipeline replacement programs, distribution service replacement programs, and other gas distribution reliability work.[131]

PG&E divides Gas Operations into what it calls nine physical asset families, and PG&E's funding requests are made in relationship to these nine asset families:

1. Gas Storage
2. Compression and Processing

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[129] PG&E Ex-03.

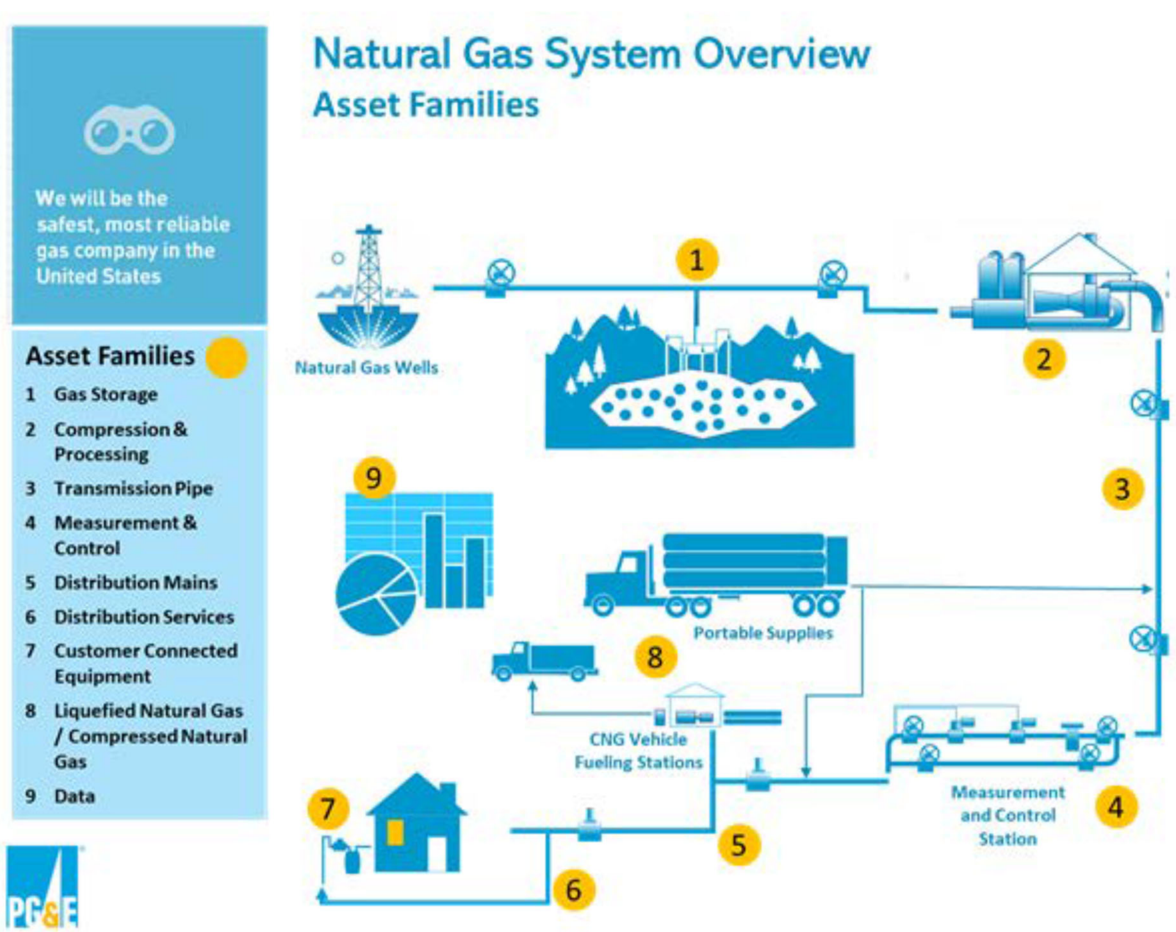
[130] PG&E Ex-03 at 1-1.

[131] PG&E Opening Brief at 92.

3. Transmission Pipe
4. Distribution Mains
5. Distribution Services
6. Customer-Connected Equipment
7. Measurement and Control
8. Liquified Natural Gas and Compressed Natural Gas
9. Data

Figure 1 is a graphical representation of the Gas Operations asset families and boundaries.[132]

FIGURE 1



132 PG&E Ex-03 at 3-4.

PG&E's requests within the following categories are disputed and discussed below:

- Distribution Mains and Services
- Transmission Pipe
- Gas Facilities
- Gas Storage
- Operations and Maintenance
- Other Gas Operations Support
- New Business and Work at the Request of Other

Forecasts for the remaining categories of expenses and capital expenditures are not in dispute. The Commission finds reasonable the uncontested forecasts in the remaining cost categories within Gas Operations.

The Commission first briefly summarizes PG&E's approach to its gas operations forecasts, including its risk management and analysis. This provides the necessary background to examine the disputed areas. The decision then turns to the disputed expense and capital program forecasts in the six Sections that follow.

3.1. PG&E's Gas Operations Forecasts

PG&E describes its forecasts as considering risks while addressing execution constraints, such as resource availability, periods of higher demand, permitting timeliness, and costs. PG&E says its forecasts also include a detailed review of its portfolio with a focus on emergency restorative and preventative work. That work supports an immediate response to public and workforce safety, customer commitments and load growth, compliance-mandated work, and risk reduction activities.[133]

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[133] PG&E Opening Brief, Section 2.1.1.3.

3.2. Risk Management and Analysis

A key element of its forecasts, according to PG&E, is risk management and analysis. PG&E identified nine Gas Operation risks all within the categories of loss of containment events, overpressure, and lack of capacity to meet customer demand.[134] Three of the nine are identified as top safety risks.[135]

PG&E states that its employees identify and manage risks for each asset family and develop programs to mitigate those risks. PG&E further explains that its Gas Operations Organization uses the multi-attribute value framework, bow-tie methodology, and risk spend efficiency (RSE) scores to evaluate risk, including mitigation and control programs for evaluating safety and reliability risks. According to PG&E, this approach is complemented by two operational risk model programs that are used to manage gas operations for individual segments of pipe: the Transmission Integrity Management Program (TIMP) and the DIMP. The outputs from these operational risk models are used as inputs to both PG&E's (a) Enterprise and Operational Risk Management model for frequency and consequence data, and (b) Gas Operations Integrated Planning Process for the system as a whole.[136]

3.3. Gas Distribution Mains and Services

The Commission addresses six disputed items regarding gas distribution mains and services in the following order: (1) Fitting Mitigation Program, (2) Cross Bore Program, (3) Gas Pipeline Replacement Program, (4) Plastic Pipe Replacement Program, (5) Reliability Service Replacement Program, and

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[134] PG&E Opening Brief at 86.

[135] The three top safety risks are: loss of containment on Gas Transmission Pipeline; loss of containment on Gas Distribution Main or Service; and Large Overpressure Event Downstream of Gas Measurement and Control Facility.

[136] PG&E Opening Brief at 84.

(6) Long-Term Gas System Planning Proceeding. As explained below, lower values are adopted than requested by PG&E, and a two-way balancing account will be used to begin the process of avoiding future stranded assets.

3.3.1. Fitting Mitigation Program (MAT JQG)

Fittings are the pipe components fused to gas main pipes and smaller service pipes that supply natural gas to customers' premises.[137] PG&E explains that in its prior GRC (A.18-12-009, PG&E's 2020 GRC) this maintenance activity type was referred to as the Mechanical Fitting Replacement Program because it targeted removal of mechanical fittings whose stainless-steel rings were found to be corroding and cracking. These stainless-steel ring mechanical fittings are no longer approved for use. PG&E has already removed some leaking mechanical fittings. PG&E plans to continue this removal process as other leaking mechanical fittings are identified but, to be more expansive, will do this under a different program, the Fitting Mitigation Program (MAT JQG).[138]

Starting in 2023, PG&E proposes to use this larger Fitting Mitigation Program to replace a type of plastic fitting known to have manufacturing defects. PG&E states that this replacement program is important because these fittings were found to fail in laboratory tests at a failure rate 14 times that of other fittings.[139] After searching installation records, PG&E states that it identified 22,000 locations in which fittings with a higher failure rate were installed between 2016 and 2017. PG&E then initiated a pilot program to develop and document the process of field locating, excavating, and repairing or replacing

[137] PG&E Ex-16 at 4-6.

[138] PG&E Ex-03 at 4-19.

[139] PG&E Ex-16 at 4-10; TURN Opening Brief at 128. All cites to TURN's Opening Brief are to TURN's Amended Opening Brief filed on November 8, 2022.

these fittings. Under this pilot program, PG&E reports that none of the replaced fittings have started leaking. PG&E states it will survey the fittings for leaks annually until all the defective fittings are replaced.[140]

PG&E requests $15.923 million for the Fitting Mitigation Program in test year 2023. The Commission adopts $2.4 million based on data from the pilot for the reasons explained below.

3.3.1.1. PG&E Position

PG&E requests that the Commission approve a TY 2023 expense forecast of $15.923 million for the Fitting Mitigation Program (MAT JQG), with the goal of replacing 2,200 plastic fittings with elevated failure rates over a 10-year period.[141] In support of its proposed forecast, PG&E asserts that it procured the original fittings with an elevated failure rate from a reputable national company and took the following actions after discovering the manufacturing defects: (1) PG&E rigorously tested the fittings, (2) determined the number and location of products that had been installed in the field, (3) determined the extent of the manufacturing issue with the manufacturer, and received assurances that the issue did not extend to other plastic fittings, and (4) quarantined the inventory of all potentially defective fittings.[142] PG&E says it pursued its legal remedies against the supplier and states that PG&E settled its warranty claim in its bankruptcy case for $225,000 based on the legal arguments made as part of that claim, including the terms of applicable warranties and contracts.[143] For purposes

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[140] PG&E Ex-03 at 4-20.

[141] PG&E Opening Brief at 95; TURN Opening Brief at 167.

[142] PG&E Opening Brief at 132–133.

[143] PG&E Reply Brief at 94-95.

of establishing a forecast, PG&E estimates the defective fittings to have a 29-year expected life.

PG&E also acknowledges that at the time PG&E filed this GRC application, the pilot project for the Fitting Mitigation Program was not complete.[144] As PG&E explains, it developed its 2023 forecast based on vendor bids, 2020 budget allocations, and an "estimate" of fittings to be mitigated over ten years but, PG&E says, it did not include the recorded results of the pilot program because the pilot was not complete at that time.[145] As a result, PG&E did not provide its final estimates for its forecast until it served its rebuttal testimony.[146]

3.3.1.2. Party Positions

In response to PG&E's proposed pace of mitigation, TURN proposes reducing PG&E's forecast for the program by 50% or $8.0 million by extending the program's mitigation pace from PG&E's proposed 10-years to 20 years.[147] TURN supports extending the replacement program over a longer period based on the following: (1) the failure rates of these fittings in the field; and (2) the program's low RSE.[148] In addition, TURN does not agree with PG&E's estimate for the useful life of 29-years for these fittings for the following reasons: (1) "PG&E's target of replacing all the fittings within ten years is based on a field study done on a totally different group of fittings that failed in service,"[149] (2) the

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[144] Cal Advocates Opening Brief at 51–52.

[145] PG&E Opening Brief at 97.

[146] PG&E Reply Brief at 93-94.

[147] TURN Opening Brief at 203–206.

[148] TURN Opening Brief at 203–206.

[149] PG&E Reply Brief at 92.

study included none of the defective fittings at issue in this program, (3) none of the fittings in the study failed; and (4) "the behavior of the fittings with manufacturing defects is different from the behavior of poorly constructed plastic fusion fittings."[150] Lastly, TURN suggests that the RSE for the Fitting Mitigation Program is 0.016, which PG&E suggests means that the program results in less than 1% of safety and reliability benefits per dollar spent.

Cal Advocates recommends no funding for the program for the following reasons: (1) ratepayers should not be responsible for a manufacturing defect, and (2) the funding request is premature and inadequately supported because it was presented late in the proceeding.[151] Cal Advocates contends that PG&E has not provided the Commission with reasonable validation of the processes, methods, and costs it proposes to undertake and incur as part of this Program. In addition, Cal Advocates contends that PG&E has not provided a description of the process of field locating, excavating, and repairing or replacing fittings — the information the pilot program was designed to gather.[152]

3.3.1.3. Discussion

Considering all these factors, the Commission is not convinced by PG&E to adopt PG&E's proposed level of funding. Nonetheless, we find that it is reasonable to forecast some level of expense in 2023 for PG&E's proposed fittings mitigation work. We do so based on the arguments presented here and because

[150] PG&E Reply Brief at 92.

[151] Cal Advocates Opening Brief at 70–73.

[152] Cal Advocates Opening Brief at 51–52.

we have approved funding for mitigation of similar manufacturing and material quality issues before.[153]

Parties, however, did not have critical information regarding PG&E's pilot program for fitting replacement until late in this proceeding.[154] As a result, the parties were unable to reasonably evaluate both the cost-effectiveness of the program and PG&E's forecast for a scaled-up program. Therefore, the Commission finds that more time is needed to review the data on the pace and cost of replacement before we can adopt PG&E's full request.

As such, the Commission finds that PG&E has not established the reasonableness of its forecast of $15.923 million for the Fitting Mitigation Program by the preponderance of evidence. The Commission finds reasonable a forecast based on the proactive replacement of fittings with an elevated failure rate at the same annual rate as the pilot, which is 480 fittings per year. Based on a unit cost of $5,004 per fitting[155] and 480 fittings per year, the Commission adopts an expense forecast for TY 2023 of $2.4 million for the Fitting Mitigation Program (MAT JQG).

We must also ensure that ratepayers secure the benefits of the warranty claim regarding defective fittings. To do so, PG&E shall explain how the $225,000 in warranty settlement proceeds will be credited to ratepayers by filing and serving a Tier 2 Advice Letter within 30 days of the effective date of this decision.

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[153] D.03-10-002, *Opinion on Bakman Water Company's General Rate Case for Test Year 2000* (October 2, 2003) at 28 (OP 3).

[154] Cal Advocates Opening Brief at 52.

[155] PG&E's 2020 pilot program recorded $1.396 to replace 279 fittings, resulting in a unit cost of $5,004 per fitting. Cal Advocates Ex-02 at 6.

3.3.2. Cross Bore Program (MAT JQK)

A cross bore is an inadvertent installation of a gas line through a wastewater or storm drain system during trenchless construction or boring. When sewers and storm drains containing cross bores are mechanically cleaned, the gas lines can be damaged and leak, causing a risk to employees and the public, particularly if damaged gas lines leak into a sewer system. Through the Cross Bore Program, PG&E looks for cross bores in wastewater lines and laterals using video equipment. PG&E reports that it repairs any cross bores identified from the inspections.[156] Since 2012, PG&E says it has identified and mitigated over 800 cross bores.

PG&E requests $33.91 million in 2023 for this program. The Commission adopts $13.13 million for the reasons explained below.

3.3.2.1. PG&E Position

PG&E states it is targeting 2022 for substantial completion of the Cross Bore Program in San Francisco, with a focus in the GRC cycle on the approximately 800,000 remaining outside of San Francisco.

PG&E's 2023 forecast is to execute 45,000 inspections annually (2023-2026) at a cost of $753 per unit (inspection) for a forecast of $33.91 million in 2023. This forecast is $2.16 million higher than the 2020 recorded amount of $31.75 million.[157]

PG&E states in support of its estimate of 45,000 inspections per year that in 2018 it completed 45,477 inspections outside San Francisco.[158] PG&E estimates the cost per inspection based on a three-year average (2017-2019) of recorded

[156] PG&E Ex-03 at 4-13.

[157] PG&E Opening Brief at 99.

[158] PG&E Reply Brief at 97.

costs and inspections, during which 12% were in San Francisco, and 88% were outside San Francisco.

3.3.2.2. Party Positions

TURN proposes a lower forecast based on a reduced inspection pace (19,313 instead of 45,000 inspections per year), a reduced cost ($680 instead of $753 per inspection), and a reduced cross bore find rate per 1,000 inspections (which fell from 7.74 in 2013 to 0.81 in 2021.)[159] TURN estimates 19,313 inspections per year based on PG&E's recorded average rate over three years (2019-2021). TURN estimates a cost of $680 per inspection based on the number and cost of non-San Francisco inspections conducted in 2019-2021. This produces a TURN proposal of $13.13 million for the test year 2023 Cross Bore Program.

TURN presents the following reasons in support of its lower forecast: (1) the relative risk of cross bores outside of San Francisco is much lower than in San Francisco, resulting in a low RSE score; (2) the declining cross bore find rate greatly increases the cost of the Cross Bore Program per cross bore found; (3) PG&E should have utilized a different methodology for its unit cost forecast;[160] (4) PG&E's assumption that the probability of a major event resulting from a cross bore loss of containment of one out of 34 is flawed; (5) PG&E's proposal to double its cross bore program outside San Francisco is not justified; and (6) there is no reason to expect a major cross bore event because "sewers are designed to mitigate gas backflow into structures."[161] In response, PG&E states that (1) cross bores outside San Francisco pose a significant risk; (2) cross bores

[159] PG&E Opening Brief at 99–101.

[160] PG&E Opening Brief at 99–100.

[161] PG&E Reply Brief at 96–97.

represent a significant risk that should be mitigated at PG&E's proposed pace; and (3) PG&E's proposed unit cost for the program is reasonable.[162]

The Commission assesses in turn the three fundamental contentions of the parties: (1) risk, (2) pace, and (3) inspection cost.

3.3.2.3. Assessment of Cross Bore Risk

The parties debate the assessment of the risk presented by cross bores. PG&E states that it has experienced seven loss of containment events as a result of cross-bores from 2016 to the present, all of which have occurred outside of San Francisco.[163] PG&E claims that this risk is significant based on its calculation of the probability of a major event resulting from a cross bore loss of containment being one out of 34.[164] On the other hand, TURN asserts that PG&E has not experienced a major incident due to cross bores, the rate of finding cross bores has diminished, and PG&E has completed inspections of all potential cross bores in the areas of highest risk.[165] In addition, TURN noted that the Cross Bore program does not mitigate a major loss of containment risk.[166]

The Commission finds that the potential risk posed by cross bores to be unclear, and that PG&E has failed to thoroughly assess its relative cost-effectiveness by ranking it against risk mitigation alternatives as required by the D.18-12-014 (S-MAP Settlement Agreement). PG&E's isolated calculation of the probability of a major event resulting from a cross bore was not made in relation to other risks and less precise than the risk factors developed and ranked

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[162] PG&E Opening Brief at 99–102; PG&E Reply Brief at 95–96.

[163] PG&E Opening Brief at 101.

[164] TURN Opening Brief at 172; *citing to* PG&E Ex-02, WP at 1-351.

[165] TURN Ex-06 at 38.

[166] TURN Ex-06 at 37.

in accordance with the S-MAP, adopted in D.18-12-014. To reduce the uncertainty inherent in risk assessments, the S-MAP requires risks to be assessed, in part, by comparing them to other risks or ranking them, which PG&E failed to do. As a result, the Commission finds that PG&E has not reasonably assessed the cross bore risk. The Commission expects an improved showing in future proceedings.

Nonetheless, the risk is not zero. For the reasons discussed below, we decline to adopt PG&E's request of $33.91 million for the 2023 forecast but authorize $13.13 million.

3.3.2.4. The Pace of Mitigating Cross Bore Risk

Parties dispute whether or not PG&E's pace of a proposed 45,000 inspections per year represents a program increase. TURN claims that 45,000 inspections per year represent an increase of over double the amount of 19,313 per year on average during the 2019-2021 period.[167] In response, PG&E states that from 2020-2022, the focus on completing San Francisco inspections reduced the number of inspections that PG&E was able to complete outside San Francisco. And, according to PG&E, in 2018 it performed fewer inspections in San Francisco and completed 45,477 inspections outside San Francisco.[168]

To assist in selecting a pace for mitigating the uncertain risk of cross-bores, TURN recommends the Commission consider the program's RSEs. TURN states that PG&E's Cross Bore Program has a relatively low RSE of 0.03. PG&E does not dispute TURN's RSE. Instead, PG&E argues that TURN's reliance on the RSE score for this program as the sole reason to delay these safety inspections is not

[167] TURN Ex-06 at 38.

[168] PG&E Reply Brief at 97.

warranted in light of the evolving nature of the Risk Assessment Mitigation Phase (RAMP) process.

The Commission finds TURN's application of RSEs to be consistent with the Commission's decision in D.18-12-014 of providing a data-driven tool to assess risk and select mitigations based on ranked assessment. Moreover, based on considering the actual inspections per year over 2019 to 2021 along with the factors above, we find TURN's proposed frequency of 19,313 inspections per year to be more reasonable than the 45,000 in PG&E's less precise analysis.

3.3.2.5. Unit Cost of Cross Bore Inspections and Cost Effectiveness

PG&E says it used a three-year average (2017-2019) of recorded costs and number of inspections to develop the Cross Bore Program unit cost of $753, with 12% of PG&E's inspections during this timeframe in the generally more costly San Francisco area and 88% outside San Francisco. While PG&E's test year 2023 forecast is for the remaining inspections to be outside San Francisco, PG&E says there will be a small population of difficult inspections outside of San Francisco each year, similar to those in San Francisco. PG&E concludes that its estimated unit cost is reasonable based on the assumption that 12% of the more complex inspections would occur annually outside of San Francisco.[169]

TURN recommends that the unit cost be reduced to $680, based on the number and cost of non-San Francisco inspections conducted in 2019-2021.[170] TURN contests PG&E's estimate by arguing that PG&E's 2017-2019 data includes over 100,000 inspections outside of San Francisco that, presumably, already include difficult inspections. In response, PG&E states that its historical data

[169] PG&E Opening Brief at 99.

[170] TURN Opening Brief at 173.

does not include 5,022 units outside of San Francisco involving difficult inspections because the 5,022 inspections have not been completed.

The Commission concludes that PG&E's identification of 5,022 difficult inspections not included in the historical data neither supports its assumption that 12% of the remaining 800,000 inspections outside San Francisco will be difficult nor invalidates that some of the over 100,000 inspections outside of San Francisco will likely be difficult.[171] In the absence of support for PG&E's figure of 12%, the Commission does not find PG&E has met its burden to demonstrate the reasonableness of its $753 unit cost estimate. We find the more reasonable estimate to be $680 based on actual 2019-2021 data which includes inspections outside San Francisco and, whether or not part of the 5,022 inspections, likely includes some difficult cases.

Therefore, the Commission finds that the rate of 19,313 inspections per year at a unit cost of $680 per inspection reasonable for a forecast for Cross Bore Program tracked in MAT JQK of $13.130 million for the 2023 test year.

3.3.3. Gas Pipeline Replacement Program (Capital MAT 14A)

PG&E's Steel Gas Pipeline Replacement Program focuses on identifying and assessing risks associated with aged steel pipe and replacing pipe at an appropriate time. PG&E requests $683.3 million over the four-year GRC period. The Commission adopts $99.20 million as explained below.

3.3.3.1. PG&E Position

PG&E requests that the Commission authorize funding to replace 37.1, 39.3, 41.4, and 43.5 miles of such pipe in 2023, 2024, 2025, and 2026, respectively,

[171] (5,022/800,000) x 100 = 0.63%.

totaling 161 miles and $683.3 million during this rate case period.[172] Compared to 2022, this amounts to an increase in funding of 31%, 42%, 53%, 65% over the same period. PG&E's proposed unit cost forecast of $770 per foot is based on a three-year average of recorded costs (2017-2019) without escalation.[173]

3.3.3.2. Party Positions

TURN recommends that PG&E's funding be reduced to five miles of steel pipe replacement per year "and an additional 10 miles per year of non-cathodically protected pipe in the next 10 years."[174] This amounts to a reduction of 101 miles and approximately $429.5 million over the four-year period. To support this reduction to PG&E's forecast, TURN claims that: (1) the program has a low RSE score and associated cost-benefit ratio; and (2) PG&E should instead focus on replacing steel pipe installed before 1924 (99 years old and older) because it has twice the leak rate as pipe installed from 1924-1940.[175]

Cal Advocates recommends reducing PG&E's 2023 steel pipe replacement mileage to the 2020 base level of 24.4 miles of pipe at a total cost of $113.385 million, asserting that PG&E failed to provide support for a higher request. Cal Advocates also argues that PG&E did not identify the segments of pipeline it plans to replace.[176]

3.3.3.3. Discussion

PG&E prioritizes pipe segments for replacement based on the relative risk of each pipe segment determined using its DIMP risk model. In accordance with

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[172] PG&E Opening Brief at 103.

[173] PG&E Opening Brief at 137; PG&E Ex-03, WP at 4-27 (Table 4-18).

[174] TURN Ex-06 at 25.

[175] PG&E Ex-16 at 4-26.

[176] Cal Advocates Opening Brief at 5-57.

federal standards regulating the transportation of natural gas,[177] PG&E's model evaluates risks using the following factors: pipe age, leak history, cathodic protection, coating, seismic activities, and population proximity. In addition, PG&E's DIMP risk model considers migration, pressure, and population density, and utilizes the likelihood of failure and consequence of failure to determine risk of failure.[178] PG&E's model is not inconsistent with the S-MAP which allows utilities to consider other factors.[179]

PG&E's DIMP risk model identified as high risk 25 of the 28.6 miles of pre-1924 steel pipe[180] and 183 miles of the steel pipe installed in 1924-1940.[181] The pre-1924 pipe is of higher risk because it has a leak rate of over twice the leak rate of steel pipe installed in the 1924-1940 time period.[182] However, PG&E did not specify any segments of pipe by age or leak rate that it proposed to replace according to its DIMP model.[183] As a result, the parties dispute the appropriate rate to replacing steel pipe.

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[177] 49 CFR § 192.1007, subdivision (c).

[178] PG&E Opening Brief at 104; 49 CFR § 192.1007, subdivision (b) requires utilities to consider the following categories of threats to each gas distribution pipeline: "Corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other issues that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include incident and leak history, corrosion control records (including atmospheric corrosion records), continuing surveillance records, patrolling records, maintenance history, and excavation damage experience."

[179] D.18-12-014, S-*MAP Settlement* at A-14, Element 26; TURN Ex-26.

[180] PG&E Ex-16 at 65 (Table 4-4).

[181] TURN Opening Brief at 103-104; PG&E Reply Brief at 103–104.

[182] PG&E Ex-16 at 65 (Table 4-4).

[183] TURN Reply Brief at 33.

PG&E seeks to increase the rate of replacing steel pipe, but its request is not driven by risk rankings, its DIMP model, or federal regulations. Rather, PG&E requests authorization to replace 161 miles of steel pipe during 2023-2026 primarily to replace its pre-1941 pipe before it reaches the end of its useful life. PG&E claims its pipe replacement rate of approximately 40 miles of pipe per year is necessary to avoid later replacing pipe at an unmanageable rate upon pipe failure.[184]

While limiting the asset age of steel pipelines to 100 years (pre-1924) may be reasonable, the Commission's earlier decisions neither require a goal of steady-state asset replacement[185] nor view such a goal in isolation.[186] For example, we must consider PG&E's request to increase this replacement rate at the same time PG&E requests increased funding to mitigate much higher risks in other parts of its operations. The Commission must also consider customer rate levels and whether those rate levels remain affordable. Moreover, even if we do apply a steady-state replacement goal, it is unlikely that utilities would be able to adhere to a specific "age of replacement" standard[187] given other long term gas planning considerations.[188] As a result, the Commission must balance the relative risks with the cost-effectiveness of PG&E's programs and other long-term goals.

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[184] PG&E Opening Brief at 105-107; PG&E Reply Brief at 101.

[185] A steady-state asset replacement program replaces an asset on a schedule before it reaches an estimate for the end of its useful life.

[186] Cal Advocates Reply Brief at 22; TURN Reply Brief at 33.

[187] TURN Reply Brief at 35.

[188] *Assigned Commissioner's Amended Scoping Memo and Ruling* (January 5, 2022) at 12. The scope of issues in R.20-01-007 includes considering how utilities will cost-effectively maintain aging infrastructure and plan to selectively decommission or "prune" the distribution system and other gas infrastructure while maintaining safe and reliable gas service.

TURN's recommendation is based on a more detailed present risk analysis. It uses RSEs to consider the relative risk of replacing two different tranches of steel pipe: (1) pre-1924 steel pipe, and (2) steel pipe lacking cathodic protection. However, some steel pipelines installed between 1924 and 1941 that are cathodically protected are leaking. Therefore, the Commission is not convinced that the rate of steel pipeline replacement should be as limited as TURN recommends.

Cal Advocates recommends maintaining the current rate of steel pipe replacement based on PG&E not specifying the pipe it plans to replace. Further, Cal Advocates asserts that PG&E generally failed to support its request for increased funding.

Considering all these factors, the Commission finds that PG&E has not provided the Commission with the information needed to evaluate the request and, therefore, has not established by the preponderance of evidence that its request for increased funding is reasonable. Considering the tradeoffs between present and long-term benefits and costs, PG&E has not justified a forecast that increases the rate of steel pipeline replacement. Rather, the Commission concludes that a forecast based on continuing the replacement rate at the 2020 base level rate at PG&E's estimated cost per foot is reasonable.

Accordingly, the Commission adopts a 2023 forecast of $99.201 million for the Steel Gas Pipeline Replacement Program (MAT 14), which is calculated at a rate of 24.4[189] miles of pipeline per year at a 2023 cost of $770 per foot.[190]

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[189] PG&E Ex-03, WP at 4-27 (Table 4-18).

[190] PG&E Ex-03, WP at 4-27 (Table 4-18).

3.3.4. Plastic Pipe Replacement Program (Capital MAT 14D)

PG&E established the Plastic Pipe Replacement Program in 2012 to mitigate risks associated with leaks from gas distribution mains and services manufactured with Aldyl-A plastic that were installed before 1985. According to PG&E, pipe made of such plastic with a formulation used before 1985 tends to crack more quickly than other plastic pipe when exposed to stress, such as stress caused by tree roots, differential settlement, or rock impingement. Plastic pipe manufactured between 1970 and 1983 has a lower resistance to crack growth than other pipe, with a forecast mean time to failure under stress of 71 years.[191] The Plastic Pipe Replacement Program prioritizes plastic main replacement projects based on the relative forecast risk of each pipe segment.[192]

PG&E requests $2.270 million over the four-year rate case period. The Commission adopts $396.4 million for the reasons stated below.

3.3.4.1. PG&E's Position

PG&E requests that the Commission authorize funding to replace 170.4 miles, 175.8 miles, 181.1 miles, and 186.5 miles in 2023, 2024, 2025, and 2026, respectively, totaling approximately 714 miles at a total cost of $2.270 billion during the rate case period. Compared to 2022, this amounts to an increase in funding of 31%, 42%, 53%, 65% over the same period. PG&E's unit cost forecast is based on a three-year average of recorded costs (2017-2019) plus escalation.[193] Therefore, the increase in cost compared to 2022 is largely based on an increase in replacement rate.

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[191] PG&E Opening Brief at 112, citing to CPUC's Hazardous Analysis and Mitigation Report on Aldyl-A Polyethylene Gas Pipelines in California (June 11, 2014).

[192] PG&E Opening Brief at 108.

[193] PG&E Opening Brief at 109.

In the 2020 GRC, D.20-12-005, the Commission adopted the settling parties' agreement that PG&E should replace an average of 139 miles per year of pre-1985 plastic pipe for a total of 417 miles over three years as a reasonable approach to addressing the risks associated with this pipe.[194] PG&E's current proposal represents a 71% increase in proposed pipeline miles to be replaced over 2023 - 2026 compared to that adopted in the 2020 settlement agreement.

3.3.4.2. Party Positions

TURN proposes a two-thirds reduction in PG&E's proposed rate of plastic pipe replacement. TURN recommends funding $171.6 million in 2023 to replace an average of 59 miles per year of plastic pipe based on: (1) low RSE scores for this activity; (2) the need to focus on pre-1973 pipe with twice the leak rate of 1973-1983 pipe;[195] and (3) an interest in avoiding stranded gas infrastructure investments before the Commission has an opportunity to examine policy options, the effects of local regulations, and the consequences of other activities (i.e., related to cost, equity, electrification, and future gas demand) that will be considered in the Long-term Gas Planning Proceeding (R.20-01-007). This could obviate the need for some pipeline replacement if gas is instead replaced with non-pipeline alternatives (e.g., electricity).

Cal Advocates and AARP recommend that the Commission authorize replacing pre-1985 plastic pipe at or close to the currently approved level of pipe replacement of 139 miles per year compared to PG&E's forecast of over 170 miles per year.[196] In particular, Cal Advocates argues that PG&E: (1) underperformed

[194] In D.20-12-005, Settling Parties included, among others, PG&E, Cal Advocates, the Office of Safety Advocate, TURN, and CUE.

[195] TURN Reply Brief at 29.

[196] PG&E Reply Brief at 109.

with this program in the 2020-2022 period (i.e., replaced fewer miles than planned); (2) has not "demonstrated a record that supports an even higher estimate of pipeline replacement miles…";[197] and (3) has not identified an increase to the risk level associated with pre-1985 plastic pipe or the segments already identified for 2021-2022. According to Cal Advocates, PG&E has not demonstrated a record supporting a higher pipeline replacement rate because it has completed only 51% of the 417 miles of pipe replacement authorized in the 2020 settlement agreement during the 2020-2022 period.[198] As a result, Cal Advocates recommends that the 2023 forecast be based on PG&E's 2021 recorded capital expenditures and recommends a forecast of $396.4 million.

AARP also recommends a lower unit cost for this program. AARP argues: (1) the program's requested replacement rate is "significantly higher" than the prior CPUC-approved replacement rate of 139 miles per year; (2) the risk level presented by Aldyl-A plastic pipe has not changed; (3) the program has a relatively low RSE score compared to undergrounding overhead electric lines; (4) "[i]t may make sense to pursue full electrification first in areas served by pre-1985 Aldyl-A pipe … to avoid replacement costs;" (5) in light of the potential decrease in the use of natural gas in the future "California should be taking actions which reduce, rather than accelerate, investments in natural gas infrastructure;" and (6) the Commission should use a lower unit cost than proposed by PG&E.

The Commission assesses the various positions by first considering background information on failure risk and modeling. This is followed by the

[197] PG&E Opening Brief at 110.

[198] CALPA Ex-02 at 9.

Commission determining the rate of replacement and the cost per mile to determine the adopted amount for the test year.

3.3.4.3. Plastic Pipe Failure Risk and Modeling

A brief review of failure risk and modeling are necessary to put the parties' positions in context.

PG&E evaluates distribution pipe segments utilizing its DIMP operational risk model based on a methodology that considers leak history, pipe age, material type, ground temperature, diameter, operating pressure, and population proximity. This model is applied to multiple materials of pipe including Aldyl-A and steel. PG&E states it regularly reviews and updates the leak information for all pipe segments in its database and reruns the model to determine the risk ranking of all pipeline segments. Information reflecting the results of the 2020 DIMP risk evaluation is shown in the "2020 Distribution Risk Assessment and Recommendations for Mitigation Analyses" report (2020 Risk Assessment).[199] Based on the DIMP model, PG&E states that the 2020 Risk Assessment identified 2,300 miles of main distribution pipe as high risk.[200] This included 208 miles of pre-1941 steel pipe and 494 miles of pre-1985 plastic pipe. The remaining 1,600 miles of high-risk pipe is in later vintages of pipe, which are not subject to the vintage steel and plastic pipe replacement programs but are instead addressed through other programs.[201]

PG&E and TURN cite five primary documents containing analyses conducted by government agencies or private consultants that provide key

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[199] TURN Ex-200 is the 2020 Risk Assessment.

[200] TURN Ex-200 at 004.

[201] PG&E Reply Brief at 103-105.

information concerning the risk posed by Aldyl-A pipelines. These include, in chronological order:

- Five PHMSA advisory bulletins concerning plastic pipe failures issued in 1999, 2002, and 2007;
- The 2013 Report from PG&E's consultant JANA Laboratories, Inc.;
- The CPUC 2014 Aldyl-A Report;
- The Commission's Office of Safety Advocate Testimony from 2019 in PG&E's 2020 rate case; and
- The CPUC Safety Policy Division's 2020 RAMP Report.[202]

TURN asserts that these documents reveal that the primary concern with this pipe is with the low ductile inner wall (LDIW) Aldyl-A pipeline manufactured from 1965 to 1972. This includes Aldyl 5040 manufactured through 1971, and 30 to 40% of the Aldyl 5043 manufactured through 1972. According to TURN, so-called "Standard 5043" Aldyl-A pipe manufactured in 1971- 1983 did not have the low ductile inner wall problems and was ten times better in resisting slow crack growth.[203]

Based on its interpretation of this evidence TURN argues that only the older plastic pipe manufactured through 1973, and thus installed "pre-1976," presents a relatively high risk of failing and leaking gas. TURN contends that the pipe installed in 1976-1984 (manufactured through 1983) is more resistant to slow-crack growth, and presents a risk of failure only if impacted by external forces such as rock impingement, tree roots, or differential settlement. According to TURN, PG&E asserts its DIMP risk-model provides the actual evidence of the

[202] TURN Opening Brief at 129.

[203] TURN Opening Brief at 118-119.

riskiest pipelines, and the model identifies only 286 miles (out of a total of about 4,460 installed miles) of the 1976-1984 plastic pipe as having high risk.[204]

The parties emphasize different aspects of the information in these reports.[205] The Commission further considers these views in determining the reasonable cost forecast below.

3.3.4.4. Rate of Plastic Pipe Replacement

The necessary funds for this program are based on (1) the rate of replacement, and (2) the cost per mile of replacement. The Commission finds the reasonable rate of replacement to be 139 miles per year as explained below.

PG&E summarizes the evidence about failure risk and modeling by stating that "the choice before the Commission boils down to whether the principle of steady state replacement should be followed to replace assets within their expected service life, or whether they should be simply run to failure, accepting the public safety and reliability risks that this entails."[206] By steady-state replacement rate, PG&E refers to the goal of replacing an asset before it reaches an estimate for the end of its useful life.[207] PG&E urges the Commission to approve PG&E's proposed plastic pipe replacement rate and funding for the plastic pipe replacement program by contending that this choice is clear.[208]

The choice is not clear, however, to the other parties and the Commission. In the Commission's Safety Policy Division 2020 RAMP report, for example, the

[204] TURN Opening Brief at 120.

[205] PG&E Reply Brief at 121. For example, PG&E emphasizes that the Commission's 2014 Staff Report and other studies say the pre-1985 plastic pipe has a much shorter expected time to failure if stressed compared to later vintages of pipe that will last much longer.

[206] PG&E Reply Brief at 110.

[207] PG&E Reply Brief at 101.

[208] PG&E Reply Brief at 110.

Safety Policy Division found that different vintages of pre-1985 plastic pipe carry varying levels of risk and advised utilities to base their risk mitigation plans on the specific years of installation and plastic material composition. The Safety Policy Division recommended that a better approach to mitigate pre-1985 plastic pipe risk would be to determine the specific vintage and plastic composition of the pipe before committing to an expensive excavation and replacement of pipe that may present no particular risk. The Safety Policy Division made this recommendation because proposed vintage pipeline replacement mitigation programs approved in previous rate cases have very low risk-spend efficiencies and a high cost to ratepayers compared to the existing controls. These risk-spend efficiency factors now present the Commission with the opportunity to consider the merits of pipe replacement programs in comparison to a range of proposals across the entire PG&E risk portfolio.

TURN, Cal Advocates, and AARP oppose PG&E's proposed increased plastic pipe replacement rate for similar reasons, including that the cost-effectiveness of this program is far less than mitigations for other risks. For instance, AARP claims that "undergrounding overhead electric lines reduces risk at a rate per dollar which is 843 times better than Aldyl-A plastic pipe replacement."[209] TURN recommends reducing the replacement rate to a rate consistent with replacing only the oldest tranche of pipe. Unlike TURN, however, AARP and Cal Advocates do not advocate for substantially reducing the rate of replacing this plastic pipe compared to previous years but, nonetheless, oppose the increase proposed by PG&E.

[209] AARP Opening Brief at 18-19.

The Commission finds that, as recommended by Cal Advocates and AARP, continuing the replacement rate of previous years is a balanced approach. The risk posed by Aldyl-A plastic pipe does not merit reducing the rate of replacement previously adopted. On the other hand, the risks posed by Aldyl-A pipe relative to the other risks to PG&E infrastructure do not merit increasing the replacement rate for such plastic pipe at this time. Additionally, it is not clear that PG&E could accomplish its proposed increased rate of work given that PG&E has only completed 51% of the existing approved pipeline replacement. Moreover, it would be particularly inappropriate to increase replacement rates at a time when the Commission is elsewhere considering how to moderate gas infrastructure investment and support non-pipeline alternatives (in proceeding R.20-01-007).

Accordingly, the Commission finds the reasonable rate of replacing this pre-1985 plastic pipe to be 139 miles per year, which was the average annual level that was approved in the 2020 GRC. As before, PG&E should continue to prioritize the highest-risk plastic pipeline segments for the earliest replacement. This estimate should enable PG&E to replace all 286 miles of 'high risk' pre-1985 Aldyl-A main pipelines before PG&E's next GRC.

3.3.4.5. Pipe Replacement Program Costs (MAT 14D)

The second element of determining the cost for this program is the cost per mile. The Commission finds the cost per mile based on 2021 recorded costs to be reasonable as explained below.

PG&E forecasts $2.27 billion to replace 714 miles over the four years of 2023-2026. This is an average per year of $567.5 million for 178.5 miles ($3.279 million per mile). PG&E's request is based on a three-year average over

2017-2019 with escalation. TURN recommends $171.6 million in 2023[210] to replace approximately 59 miles per year[211] ($2.908 million per mile). Cal Advocates bases its estimate on 2021 recorded costs and proposes $396.4 million in 2023 to replace 139 miles per year ($2.852 million per mile).[212]

The Commission finds Cal Advocates' proposal to be more convincing than that of PG&E's request or TURN 's recommendation. Cal Advocates' proposal is consistent with our above adopted estimate for the replacement rate of 139 miles per year. We also find Cal Advocates' estimate for 2023 based on 2021 recorded costs more compelling than PG&E's use of a three-year average based on more distant years (2017-2019) with escalation. Moreover, the Commission finds Cal Advocates' recommendation to be consistent with the ratemaking principles discussed in Section 1.5, above, consistent with Commission precedent,[213] and appropriate for rate modeling purposes. Accordingly, for the Plastic Pipe Replacement Program (MAT 14D), the Commission adopts $396.395 million for 2023 based on the above adopted pipe replacement rate of 139 miles per year.

3.3.5. Reliability Service Replacement Program (Capital MAT 50B)

The Reliability Service Replacement Program proactively replaces gas services to improve system safety in accordance with pipeline regulations. As part of this program, PG&E replaces services that are too shallow, services with corroded or bent risers, and meters in unsafe locations. Service replacements that

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[210] TURN Opening Brief at 155.

[211] TURN Opening Brief at 152.

[212] PG&E Opening Brief at 109.

[213] D.21-03-031 at 67.

are performed in conjunction with main replacements are not funded in this program.[214] PG&E also has a separate program (MAT 50M) to replace services identified during routine maintenance and inspection activities.

PG&E requests $22.036 million for 2023. The Commission adopts $11.7 million as explained below.

3.3.5.1. PG&E Position

PG&E requests authorization from the Commission to fund the replacement of 800 service lines per year at a cost of $22.036 million in 2023, and $91.3 million total for the 2023-2026 period.[215] PG&E establishes the rate of 800 per year by starting from the three-year historical average (2017-2019) of 427 service replacements, and rounding the number up to 500 (not including unidentified services). PG&E then added 300 services per year based on PG&E's estimate of "vintage services," for the total estimated replacement of 800 per year.

PG&E characterizes the additional 300 services as "vintage services" based on lack of records, age, and other characteristics. PG&E has found 6,257 services without identifying records and assumes that half of these services are pre-1985 vintage. PG&E proposes replacing 300 of these services per year, so that it would replace half of the vintage services within 10 years.[216]

PG&E's estimates an approximate average cost of $27,435 per service based on a three-year average (2017-2019) of recorded costs with escalation.[217]

[214] PG&E Ex-03 at 4-34; PG&E Opening Brief at 124-125.

[215] PG&E Ex-03.

[216] PG&E Ex-03 at 4-34; TURN Opening Brief at 166 to 167.

[217] PG&E Opening Brief at 124.

3.3.5.2. Party Positions

TURN and Cal Advocates oppose PG&E's request for an additional $34.3 million for the 2023-2026 period to replace unidentified services. They oppose replacing 300 unidentified services a year because (1) PG&E has not demonstrated a loss of containment risk for replacing this number of services, and (2) customers should not fund the replacement of services that should have been maintained with the proper records.[218] In addition, Cal Advocates argues that PG&E failed to comply with its legal obligation to maintain proper records. Also, TURN asserts that PG&E has only replaced two vintage services due to leaks.[219] The parties do not dispute the replacement of the other 427 services per year.

3.3.5.3. Discussion

PG&E contends that it is prudent to replace 300 services per year that lack records because: (1) PG&E assumes that the services lacking records were installed prior to 1985 and assumes that they pose a loss of containment risk due to the possibility that they were constructed of materials with time-dependent risk, and (2) there is no evidence that the lack of records for these services was due in any way to non-compliance by PG&E with any previous record keeping requirements.[220]

The Commission disagrees. PG&E does not convincingly demonstrate that the vintage services pose a loss of containment risk that warrants replacing half of the services lacking records over 10 years. In essence, PG&E requests approximately $34 million to replace pre-1985 services for which it has

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[218] PG&E Opening Brief at 125.

[219] TURN Ex-06 at 27.

[220] PG&E Opening Brief at 125-126.

inadequate records and argues that PG&E should be allowed to replace this pipe because it was not required to keep records. To the contrary, PG&E in fact was not required to keep records. For example, in D.15-04-021, the Commission found that PG&E's failure to keep adequate pipe records was in violation of Pub. Util. Code Section 451 (which requires PG&E to maintain its equipment as necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public).[221]

PG&E's request to replace unidentified services is denied. Moreover, the Commission does not find that PG&E has supported rounding up the number of services to be replaced by 73 per year.

For these reasons, for the Reliability Service Replacement Program (MAT 50B) Commission adopts as reasonable a replacement rate of 427 services per year at a cost of $27,435 per service[222] resulting in a Reliability Service Replacement Program cost of $11.715 million for 2023.

3.3.6. Long-Term Gas System Planning Proceeding

The Commission finds that, in relation to the Long-Term Gas Planning Proceeding (R.20-01-007), the funds for replacement of gas services and equipment should not be authorized if those funds can be repurposed to support electrification, thereby eliminating the need for gas main replacements or the costs associated with closing those mains. A two-way balancing account will be used as explained below.

Regarding gas pipeline replacements, TURN asserts that drastically reducing spending on gas pipeline replacement programs is justified because

[221] Cal Advocates Opening Brief at 59.

[222] PG&E Ex-03, WP at 4-30 (Table 4-19).

replacing pipes that will be abandoned due to future reductions in the use of gas could strand assets.[223] The ratemaking principle of stranded assets refers to the potential financial burden on ratepayers for the cost of utility assets not fully utilized. PG&E believes that reducing gas pipeline replacements to avoid stranding assets is not warranted, however, because: (1) a Commission adopted transition framework for the long-term future of natural gas utilities has not been finalized; (2) PG&E has an obligation to continue providing safe, reliable, and affordable service to its customers by the ongoing investment in the gas system despite any potential decline in throughput; and (3) PG&E's gas distribution mains would be deactivated in an electrification scenario only once all downstream services on that main were converted to an alternative energy source. The parties also made these arguments in relation to the rate of replacement of plastic pipe in Section 3.3.4, above.[224]

The arguments regarding stranded investment and costs raise valid concerns. These concerns are most relevant to sections of pipe and equipment closest to consumers where pruning can begin. PG&E says it foresees a long-term future for its gas mains despite some pruning due to a continued need to serve customers downstream of areas that may have been converted to an alternative energy source.[225] However, how long gas infrastructure will be needed will partly depend on how soon customers fully transition from using gas to solely using electricity. This transition will depend in part on the extent to which utilities and the Commission establish processes for facilitating this transition.

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[223] TURN Opening Brief at 153.

[224] PG&E Reply Brief at 123.

[225] PG&E Reply Brief at 123.

The sooner all customers on a given section of a gas main pipeline electrify, and that section is not the only main serving other areas, the sooner sections of a gas main may be retired. How this can be facilitated and incentivized is a complex question to be addressed in the Long-Term Gas Planning Proceeding (R.20-01-007). The questions to be considered may include, for example, whether the repurposed funds were from capital or expense accounts.

In the instant proceeding, the Commission finds that the replacement of gas services and equipment should not be authorized if such funds can be repurposed to support electrification that obviates the need for those gas mains, or costs associated with closing those mains. Funds forecasted for distribution main or service line replacement may instead, if authorized by the Commission, be used to incentivize customers to partially or completely convert their homes from gas to electricity. Through another proceeding, such funds might be used to purchase electric stoves and other appliances, such as water heaters and heat pumps, for example. Funds may also be needed to inform the public of this option.

The process of using funds forecasted for replacing gas main lines, service lines, and other equipment that may be diverted to the Alternate Energy Program is discussed in Section 3.12. This way, the Commission can provide an incentive that will avoid incurring stranded assets by pruning gas lines at the customer end of the system. To begin this process, the cost of the gas capital assets not replaced in MAT 50B but used to incentivize electrification shall be added to a two-way balancing account to track additional capital investments in the Alternative Energy Program (MAT AB#) addressed in Section 3.12., below through a Tier 1 Advice Letter.

3.4. Gas Transmission Pipe

PG&E's states that its transmission pipe assets includes approximately 6,600 miles of natural gas pipelines and associated major components, including valves. These facilities transport gas from receipt points in PG&E's transmission pipeline system to distribution centers, storage facilities, or large customers. The average age of PG&E's transmission pipe system is approximately 50 years and ranges in size from four inches to 3.5 feet in diameter. Schedules for assessing and maintaining this pipe are regulated by the and the federal Pipeline and Hazardous Materials Safety Administration (PHMSA).

The transmission pipe assets consist of 29 categories of expenses, of which parties dispute cost estimates in 14. It also includes 20 categories of capital Maintenance Activity Types (MATs), of which parties dispute cost estimates in nine.[226] PG&E also recommends changes to seven existing memorandum and balancing accounts related to its transmission system, of which parties dispute proposed changes in five. We find reasonable and adopt the undisputed expense and capital forecasts, plus the undisputed recommendations to modify two of the existing accounts.

In this Section we address and resolve the disputes regarding the 14 expense categories, nine capital categories, and the five memorandum and balancing account issues. We identify and address these in the following order:

Table 3-A:
Summary Of Disputed Expense, Capital And Account Issues

Decision Section	Disputed Program	Impacted MATs	Category [1]
3.3.1	In-Line Inspection (ILI)	75P, 98C, HPB, HPI, HPR	E and C

[226] PG&E Opening Brief at 127, 161, and 162; PG&E Ex-03 at 216-217.

Decision Section	Disputed Program	Impacted MATs	Category [1]
3.3.2	Direct Assessment	HPC, HPJ, HPK, HPN, HPO, HPP, HPU	E
3.3.3	Strength Testing	75Q, 75R, 75U, HPF, HPM, JT6	E and C
3.3.4	Vintage Pipe Replacements	75E	C
3.3.5	Shallow and Exposed Pipe (Including Water and Levee Crossings)	75K, 75M, 75T	C
3.3.6	Public Awareness	JT0	E
3.3.7	Transmission Integrity Management Program (TIMP) Balancing and Memorandum Accounts	N/A	BA and MA
3.3.8	In-Line Inspection (ILI) Program Balancing and Memorandum Accounts	N/A	BA and MA
3.3.9	Internal Corrosion Direct Assessment Memorandum Account	N/A	MA

[1] Categories: C is Capital; E is Expense; BA is Balancing Account; MA is Memorandum Account

3.4.1. In-Line Inspections (Capital & Expense Major Work Categories 75, 98, and HP)

To comply with federal regulations, PG&E must perform an initial (i.e., baseline) assessment of transmission pipelines and perform re-assessments every seven years using one of several allowable methods, including both in-line inspections (ILIs) and direct assessments.[227] We address ILI in this Section, and direct assessments later.

ILIs are those using technologically advanced inspection tools called "smart pigs" that travel inside the pipeline. California law requires that intrastate gas transmission line segments shall be capable of accommodating in-line

[227] PG&E Opening Brief at 163.

inspection devices where warranted.[228] In 2011, the Commission required gas pipeline operators to develop implementation plans that consider retrofitting pipelines to allow for in-line inspection tools.[229] In 2016, the Commission concluded that the reasonableness of PG&E's revenue requirement for gas transmission must consider customer affordability along with new safety requirements.[230] The balance between cost and safety requires utilities to consider the cost-effectiveness of its risk management programs. This balance has continued to evolve. In 2021, the Commission adopted safety performance metrics in D.21-11-009, including the miles and percentage of transmission pipelines inspected annually by inline inspection.[231]

PG&E's ILI program consists of three phases. First, a pipeline typically must be upgraded to allow it to receive ILI tools to perform the actual assessment. Second, PG&E conducts baseline assessments and re-assessments of the gas transmission pipeline.[232] Third, PG&E may be required to schedule excavations to repair and/or replace certain portions of a pipeline based on the data gathered during the assessment.

PG&E's forecast for ILI in 2023 is $363.965 million.[233] The following areas of this forecast are disputed: Capital & Expense Major Work Categories (MWCs)

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[228] Pub. Util. Code § 958(c)(3).

[229] D.11-06-017, OP 8 at 32.

[230] D.16-06-056, Conclusion of Law 8 at 450.

[231] D.21-11-009, Appendix B at 3 and 5; TURN Opening Brief at 221; PG&E-16-E at 5-13.

[232] PG&E Opening Brief at 163.

[233] PG&E Ex-3-ES at iii and v.

75 (Gas Transmission Pipeline Reliability), 98 (Gas Transmission Integrity Management), and HP (Direct Assessment).[234]

3.4.1.1. ILI Upgrades (Capital MAT 98C)

An ILI Upgrade performs capital work on a gas transmission pipeline segment so that the pipeline segment can subsequently be inspected and assessed by ILI tools. Without an ILI Upgrade, an ILI assessment cannot be performed.[235] ILI Upgrades involve the installation of smart pig inspection tool launchers and receivers as well as replacing certain segments of pipe, valves, fittings or other appurtenances that may obstruct the movement of the smart pigs.[236] Parties dispute the number and cost of these ILI assessments and inspections.

3.4.1.1.1. Number of ILI Upgrades

PG&E started upgrading gas transmission to be ILI capable in 2000. PG&E states that by the end of 2020, PG&E had upgraded 43% of its system, and by 2022, 56% of the system will be upgraded.

The Commission established the current rate of ILI upgrades in the last gas transmission and storage GRC at 12 per year, adopting a reduced rate from PG&E's proposal of 18 ILI upgrades per year. PG&E requests authorization here to maintain the rate of upgrading 12 sections of its transmission pipelines per year during this rate case cycle. At that rate, PG&E states that 69% of PG&E's system will be ILI capable by 2036,[237] which will be on par with other utilities.[238]

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[234] PG&E Opening Brief (Glossary) at 883.

[235] PG&E Reply Brief at 129.

[236] TURN Opening Brief at 216; PG&E Ex-03 at 5-22.

[237] PG&E Ex-03 at 235.

[238] PG&E Ex-03 at 234-235.

TURN recommends reducing the number of ILI upgrades during the rate case period from 12 to four per year. TURN bases this recommendation on: (1) ILI upgrades and assessments not being required by federal regulations, state law, or Commission precedent; (2) ILI upgrades are not cost-effective as demonstrated by their low RSE score; (3) PG&E has already prioritized its ILI Upgrades Program to upgrade the highest risk gas transmission pipelines first, with those highest priority segments now ILI enabled[239], and (4) ILI upgrades are unnecessary because the Commission is considering the termination of natural gas pipelines in the future. TURN acknowledges that PG&E must continue to provide safe and reliable gas service for the foreseeable future, and must do so no matter how quickly there is a decrease in the use of natural gas (with the decrease depending upon upcoming Commission decisions regarding the long term natural gas strategy).[240] However, TURN argues that the Commission must increase its scrutiny of the cost effectiveness of ILI upgrades as gas use declines to reduce the risks associated with (a) stranding assets, (b) increasing PG&E's gas transmission rate base, and (c) eroding the affordability of this essential utility service. In response, PG&E contends the current rate of ILI upgrading is appropriate because ILI capability is the standard in the industry for safety and reliability, and PG&E's ability to inspect its entire pipeline system lags behind the industry.

Parties do not dispute that additional ILI capability will allow PG&E to evaluate and manage its pipelines' current and future health more effectively.[241]

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[239] TURN Ex-04 at 9-12; PG&E Reply Brief at 165-166.

[240] TURN Reply Brief at 53-55.

[241] PG&E Ex-03 at 234-235.

The issue is whether the number and cost per upgrade requested by PG&E is reasonable and affordable considering the other needs on PG&E's entire system.

We are persuaded by TURN. PG&E has not convincingly demonstrated that performing ILI upgrades at the rate of four segments per year would fail to meet the requirements of federal and state law and regulations, nor would it conflict with prior Commission decisions. Moreover, the lack of cost-effectiveness of ILI upgrades disfavors performing them at the pace requested by PG&E. TURN shows, for example, that the RSE for PG&E's proposal is 0.08, ranking the ILI Program 171st out of 247 programs for which PG&E calculated an RSE. This translates to a benefit-cost ratio of only 0.0159, or a benefit of 1.6 cents of risk reduction for every dollar spent.[242] Compared to the costs and benefits of the combined external corrosion direct assessment and stress corrosion direct assessment costs every seven years (discussed below), it is unreasonable for ratepayers to pay for more than four ILI upgrades per year.[243] As a result, the Commission authorizes funding for PG&E to perform ILI upgrades at the rate of four segments of transmission gas pipeline per year. In addition, the Commission encourages parties to consider further development in the next GRC proceeding of the analysis regarding risk reduction, operational benefits, and costs of ILI inspections.

3.4.1.1.2. Cost of ILI Upgrades

PG&E's forecasts the base cost per ILI upgrade to be $16.058 million in 2020 or $17.2 million in 2023. PG&E states that this unit cost is higher than the 2020 unit cost because PG&E had not previously included the full cost of each

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242 TURN Reply Brief at 50.

243 TURN Opening Brief at 193-194.

project, such as costs for engineering, permitting, and carry-over costs associated with closing out a project. Carryover costs are costs that are incurred after a project becomes operational to close out the project, such as street paving where a project required a street to be excavated or site remediation. These costs may occur a year or more after a project is finished.[244]

To develop its ILI upgrade unit cost forecast, PG&E used actual ILI upgrade costs from 2016-2019. Carryover cost information for projects completed in some of these years was not available when PG&E submitted its application in June 2021. As a result, PG&E used actual carry-over costs from pre-2016 projects as a proxy for the carry-over costs associated with 2016-2019 projects.[245]

TURN recommends a unit cost of $13.533 million in 2023. In support, TURN contends that PG&E's method produces inflated unit costs and forecasts by combining carryover costs from (1) some number of projects that became operational before 2016, (2) costs associated with some number of future projects that will come online after 2019, and (3) costs associated with projects coming online from 2016-2019.[246] As a result, TURN recommends using an alternate method based on percentages to estimate average carryover costs. According to TURN, this ensures that carryover costs are attributed to the correct project despite occurring in a later year.[247]

The Commission finds TURN's methodology to be the most accurate because it uses more recent data and more reasonably aligns carryover costs to the correct project despite occurring in a later year. Accordingly, we adopt a unit

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[244] PG&E Opening Brief at 175.

[245] PG&E Opening Brief at 176.

[246] TURN Opening Brief at 226.

[247] TURN Opening Brief at 228.

cost for 2023 of $13.533 million per ILI upgrade project. Based on the rate of four ILI upgrades per year, the Commission adopts a forecast for traditional ILI upgrades tracked in MAT 98C in 2023 of $54.132 million.

3.4.1.2. Traditional and Non-Traditional ILI Assessments (Expense MAT HPB and Expense HPR)

PGE's traditional ILI assessments involve moving an inspection tool through a pipeline driven by pressure differentials generated by gas flows to assess threats to the integrity of the pipeline.[248] PG&E performs non-traditional ILI assessments by moving an ILI tool through the interior of a pipeline by means other than gas pressure differentials, such as robotic and tractor tools or winching with a cable.[249] Parties dispute the number and cost of these inspections.

PG&E requests authorization to perform 108 traditional and 48 non-traditional ILI inspections assessments during 2023-2026 rate case period at a forecasted total cost of $57.230 million and $13.442 million respectively.[250] PG&E states that in this GRC it used an improved forecast calculator, resulting in the 2023 forecast being $10.9 million lower than 2020 recorded costs. PG&E's asserts that its forecast is driven by: (1) a pace necessary to complete first time ILI inspections by 2037, and (2) completion of ILI reassessments within seven years in accordance with federal regulations and PG&E's procedures.[251] According to

[248] PG&E Ex-16 (Rebuttal) at 5-23.

[249] PG&E Opening Brief at 181.

[250] PG&E Opening Brief at 143.

[251] PG&E Ex-03 at 5-31.

PG&E, its 2023 ILI inspections are based on its analysis of cost and other characteristics of ILI Inspections completed during the years 2017-2019.[252]

TURN recommends reducing both the cost per inspection and the number of traditional inspections. In support of a lower cost, TURN states that its analysis is based on updated data and uses the best regressions for the data. TURN testifies that its result is a forecast of $48.660 million for traditional ILI inspections ($8.570 million less than PG&E) and $11.396 million for non-traditional ILI inspections ($1.787 million less than PG&E).

TURN does not disagree with PG&E's number of 48 non-traditional inspections. With regard to the number of traditional ILI assessments, TURN focuses on two categories of assessments: (1) eliminating 28 traditional ILI Inspections associated with pipelines that are not yet ILI enabled, and (2) deferring 23 projects that have compliance dates in 2027.[253] We agree with regard to eliminating the 28 traditional ILI assessments. This is consistent with Section 3.3.1 above wherein we only approve a forecast for ILI upgrades of four transmission pipeline segments per year.

TURN also argues that 23 ILI inspections can be reduced by deferring them to the next rate case cycle because these inspections do not have federal compliance deadlines until 2027.[254] We agree. PG&E states that it is prudent to perform these inspections before 2027 to allow PG&E to take into consideration impacts of outages for an ILI assessment on system reliability.[255] PG&E, however, has not reasonably explained why ILI inspections impact system reliability when

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[252] TURN Opening Brief at 230.

[253] PG&E Reply Brief at 174-175.

[254] TURN Reply Brief at 235.

[255] PG&E Opening Brief at 145.

ILI inspections are not intrusive and do not require a pipeline to be shut down while they are being conducted.[256] In addition, PG&E has not met its burden to explain why it cannot prioritize completing ILI inspections of 23 pipeline segments with compliance deadlines in 2027 all within 2027. Accordingly, the Commission finds the recommendation to defer 23 ILI inspections to the next GRC cycle to be reasonable.

With regard to the unit cost of traditional and non-traditional ILI assessments, PG&E contends that TURN's regression analysis is flawed because it omitted four projects out of 25 total projects (i.e., TURN failed to use 16% of the project data) and inappropriately removed outliers from the same analysis.[257] TURN states that it used updated data and has systematically analyzed the best regression form for the data in each category.[258] However, TURN does not completely address the questions raised by PG&E. For this reason, the Commission finds PG&E's unit cost for this forecast persuasive. By eliminating 28 ILI inspections and deferring 23 of PG&E's forecast 108 inspections, the Commission adopts a forecast that includes performing 57 traditional ILI inspections during the 2023-2026 rate case period. We also adopt the undisputed number of 48 non-traditional inspections. The Commission adopts PG&E's estimated unit cost for traditional and non-traditional ILI inspections for the reasons discussed above. As a result, the Commission adopts a forecasted total cost of $7.551 million in 2023 for traditional ILI inspections (HPB) and $3.360 million in 2023 for non-traditional ILI inspections (HPR).

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[256] TURN Opening Brief at 195.

[257] PG&E Opening Brief at 142.

[258] TURN Amended Opening Brief at 191.

3.4.1.3. Direct Examination & Repair Following ILI Assessments (Capital MAT 75P and Expense MAT HPI)

If specific anomalies in a pipe are identified following an ILI assessment, PG&E will conduct further evaluation and repairs, as required by federal regulations. This is referred to as direct examination and repair (DE&R). DE&R includes work forecasted and accounted for as both expense and capital costs.[259]

3.4.1.3.1. Direct Examination & Repair Capital (MAT 75P)

For capital costs, PG&E requests $15.004 million in DE&R costs (MAT 75P) for 2023.[260] PG&E states that its estimate is calculated based on the average historical sub-program cost from 2017-2019 with an escalation factor to arrive at the 2023 forecast. PG&E states that the capital repair is driven by the requirements under 49 CFR Part 192 and PG&E's procedures to repair anomalous findings from both traditional and non-traditional ILI inspections the year before.[261]

TURN proposes a reduction for MAT 75P based on the average capital repair costs from 2016-2020 (rather than PG&E's use of capital repair costs from 2017-2019). TURN states that this makes the methodology for estimating DE&R capital consistent with TURN's basis for its estimate of the DE&R expense calculation (discussed below). TURN estimates the average capital cost for 2016-2020 to be $12.034 million in 2020 dollars and $12.868 million in 2023 dollars.[262] In further support of its number being lower than PG&E's, TURN

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[259] PG&E Opening Brief at 146-147.

[260] PG&E Opening Brief at 147.

[261] PG&E Ex-03 at 5-35.

[262] TURN-04 at 34.

argues that this data series shows that PG&E's costs have dropped significantly since 2016.[263]

The Commission adopts TURN's recommendation of $12.868 million in 2023 for the DE&R capital costs (MAT 75P). We do this because it is based on the longer data series (2016-2020). PG&E objects to the use of 2016 data because, according to PG&E, the recorded capital costs for 2016 were abnormally low compared to later years. PG&E attributes this to using more technologically advanced (and costly) inspection tools after 2016.[264] We are not persuaded. Even if the cost was lower in 2016, the trend is downward. Our adopted result recognizes that trend.

3.4.1.3.2. Direct Examination & Repair Expense (MAT HPI)

For expense costs, PG&E requests $71.464 million in DE&R expenses (MAT HPI) for 2023.[265] To derive this estimate, PG&E states that it first calculated a DE&R cost of $129,738 per mile for both traditional and non-traditional ILI inspections completed in 2020. PG&E then applies its calculated DE&R cost per mile to its forecast of traditional and non-traditional ILI Inspections during the 2023-2026 period, with one quarter of those costs being escalated to 2023.[266] PG&E asserts that its forecast reflects an increase in the number of DE&R digs attributed to an increase in miles of ILI assessments performed.[267]

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[263] TURN Reply Brief at 46.

[264] PG&E Opening Brief at 147.

[265] PG&E Opening Brief at 148.

[266] PG&E Ex-03 at 5-32.

[267] PG&E Opening Brief at 148.

Cal Advocates recommends that the Commission authorize funding for 2023 at the 2020 recorded amount of $32.048 million. According to Cal Advocates, PG&E fails to support its substantial increase in forecasted costs (from $32.048 million in 2020 to $71.464 million in 2023).[268] Cal Advocates states that PG&E's DE&R work activities are dependent on (1) Traditional ILI inspections (tracked under MAT HPB), (2) Non-traditional ILI inspections (tracked under MAT HPR), and (3) Traditional ILI upgrades (tracked under MAT 98C). PG&E's forecasts for all three ILI programs are lower than the base year level, according to Cal Advocates, and do not support an increase in the DE&R work activities and expenses.[269]

TURN accepts PG&E's methodology for calculating the DE&R expense cost but recommends that the unit cost be based on 2016-2020 data, consistent with TURN's approach for DE&R capital costs. According to TURN, the resulting average is based on considerably more projects. In further support, TURN reports that this approach noticeably reduces the standard deviation of the sample. The result is a TURN recommended unit cost of $113,258 per ILI mile.[270] TURN also proposes elimination of 51 projects (757.55 miles) from PG&E's proposed traditional ILI inspections, resulting in an average annual mileage of 397.35.[271] Based on these adjustments, TURN 's recommendations produce a forecast of $45.003 million for 2023.

The Commission finds TURN's proposal of $113,258 per ILI mile for 397.35 miles to be the most persuasive because it is based on the same longer

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[268] Cal Advocates Opening Brief at 61.

[269] Cal Advocates Ex-02 at 19-20.

[270] TURN Opening Brief at 197, based on a correction by TURN to earlier arithmetic error.

[271] TURN Opening Brief at 197.

data series (2016-2020) that we use for DE&R capital costs. The longer data series includes more projects and reduces the standard deviation of the sample. Further, it is consistent with the reduction of 51 projects in ILI Assessments (Expense MAT HPB and Expense HPR) we adopt above for the 2023-2026 rate period. Therefore, we adopt a forecast for Direct Examination & Repair expenses (MAT HPI) for 2023 of $45.003 million.

3.4.2. Direct Assessment (MWC HP)

Besides in-line inspection, direct assessment is another method for assessing pipeline integrity. Direct assessment includes four types: External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA), Stress Corrosion Cracking Direct Assessment (SCCDA), and Direct Examination. Of the numerous forecasts for maintenance activities related to Direct Assessment, the following seven are disputed: (1) ECDA indirect inspections; (2) ECDA direct examination; (3) ICDA engineering; (4) ICDA digs, including the relationship to Cal Advocates' suggestion of the continued use of the ICDA Memorandum Account (ICDAMA); (5) SCCDA engineering and surveys; (6) SCCDA digs; and (7) direct examinations pertaining to the TIMP.

3.4.2.1. External Corrosion Direct Assessment Indirect Inspections (Expense MAT HPC)

ECDA indirect inspections involve diagnostic testing surveys to assess the threat of external corrosion on a pipeline. PG&E expects to complete ECDA indirect inspections on 268 miles of transmission pipelines in high consequence areas (HCAs) during the rate case period.[272] PG&E's 2023 forecast for ECDA

[272] PG&E Ex-03 (November 2021) at 5-42.

indirect inspections is $8.106 million[273] based on using 2017-2019 data. PG&E states that its 2023 forecast is higher than 2020 recorded data because of an increased number of digs forecasted in 2023.[274]

TURN proposes a reduced forecast of $6.895 million. TURN's proposed reduction is based on a reduced unit cost of $94,069 per survey mile using a longer period of historical recorded cost data (2014-2019) and application of an inflation factor for recorded costs from 2014 through 2016.[275] PG&E disagrees with TURN's lower unit cost per ECDA survey mile because the years added by TURN (2014-2016) represent a period when PG&E's ECDA procedures were going through a number of changes that impact the amount and types of ECDA surveys.

We are persuaded by TURN's evidence based on a longer period of data, and do not find PG&E's explanation compelling since there is a lack of evidence in the record detailing PG&E's new procedures.[276] Therefore, the Commission finds TURN's forecast to more accurately reflect the ECDA program costs. Accordingly, the Commission adopts a forecast of $6.895 million to complete ECDA indirect inspections (under expense MAT HPC) on 268 miles of transmission pipelines in high consequence areas during the rate case period.

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[273] PG&E Ex-3-ES at iii.

[274] PG&E Ex-03 (November 2021) at 5-43.

[275] TURN Ex-04 Workpaper: TURN ECDA workpapers—TURN's Revision of PG&E Workpaper Table 5-12 Errata.

[276] Hearing Transcript, Vol. 5 at 906; Cal Advocates Ex-29 which excerpts from Ch. 5 of the GT&S rate case.

3.4.2.2. External Corrosion Direct Assessment Direct Examination (Expense MAT HPN)

After an ECDA indirect inspection survey, PG&E may perform an ECDA Direct Examination to further assess and evaluate external corrosion pipeline threats. PG&E's 2023 forecast for ECDA direct examinations is $34.393 million for 168 digs per year[277] at a certain unit cost.[278]

Cal Advocates argues that PG&E's number of digs per year is arbitrary because PG&E has not applied a consistent standard or methodology for its calculation. They recommend a simpler methodology based on PG&E's most recent ECDA work data completed in 2021 to estimate the 2023 level.[279] As a result, Cal Advocates recommends a 2023 forecast of $14.675 million for the ECDA direct examination program based on a lower forecast of digs of 75 per year.

With regarding work to be completed per year, we are persuaded by PG&E to adopt 168 digs per year given that PG&E developed its forecast of the number of digs based on a project-by-project review of ECDA inspections that will occur during the rate case period and by applying a series of factors to each of these inspections to determine the estimated number of digs.[280] PG&E also explained that its forecast considers the conditions of the actual projects to be assessed during this rate case period.[281]

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[277] PG&E Reply Brief at 150; PG&E-3-ES at iii.

[278] TURN's recommendation for MAT HPN was $34.712 million which is higher than PG&E's current forecast included in Exhibit PG&E 3-ES (as of August 19, 2022), eliminating TURN's proposed reduction rather than an increase to PG&E's proposed forecast. PG&E Opening Brief at 151, Table 3-17, note b.

[279] Cal Advocates Opening Brief at 85.

[280] PG&E Reply Brief at 150 to 152.

[281] PG&E Ex-16 (Rebuttal) at 145.

Therefore, based on PG&E's number of digs, the Commission adopts PG&E's forecast of $34.393 million for 2023 for 168 ECDA direct examination digs per year (under ECDA Direct Examination Expense MAT HPN).[282]

3.4.2.3. ICDA Engineering (Expense MAT HPJ)

ICDA engineering analyzes several factors to determine the feasibility of conducting ICDA on a pipe. Those factors include construction records, operating and maintenance histories, pipeline features, gas and liquid analysis reports, inspection reports from prior integrity evaluations or maintenance actions, and flow modeling to inform dig selection.[283] For 2023, PG&E forecasts $0.812 million for ICDA engineering. Cal Advocates agrees with PG&E's ICDA engineering forecast.[284]

TURN proposed reducing 2023 ICDA engineering expenses by $0.175 million to a recommended level of $0.671 million.[285] TURN asserts that PG&E's sample data for developing unit costs over 2017-2019 is too narrow given the recorded variation in project costs.[286] TURN recommends using a combination of the 2017-2019 data plus the 2014-2016 recorded data that PG&E produced in the 2019 Gas Transmission and Storage rate case.[287] TURN states that its approach uses 49 projects to measure the cost per dig and survey cost per mile instead of the sample of 15 projects that PG&E proposes to use. TURN's estimate results in an estimate of $57,126 per project for engineering costs in

[282] TURN Ex-04, Attachment B: Revision of PG&E WP Table 5-12 Errata.

[283] PG&E Ex-16-E (Rebuttal) at 5-42 and 5-43.

[284] Cal Advocates Opening Brief at 139.

[285] TURN Opening Brief at 199-200.

[286] TURN Opening Brief at 200.

[287] A.17-10-007; TURN Opening Brief at 199.

2020 dollars, which TURN applies to pipeline projects that PG&E identifies as being required to meet compliance during 2023-2026.

The Commission finds that TURN's lower unit cost per dig is more convincing because it uses a longer period of historical recorded cost data (2014-2019) with more projects. We adopt TURN's forecast of $0.671 million for ICDA engineering in 2023 (Expense MAT HPJ).

3.4.2.4. ICDA Digs (Expense MAT HPO)

ICDA digs include excavations and direct examinations of pipelines to determine whether the pipe has lost metal due to internal corrosion. This activity also includes evaluating the remaining pipeline strength and performing remediation, if required.[288] PG&E's forecast for ICDA digs (MAT HPO) is $12.9 million for 2023.[289]

Parties raise two issues. First, Cal Advocates recommends that the Commission not authorize any funding for ICDA digs in this GRC but require PG&E to continue to track expenses for ICDA digs in a memorandum account. In support, Cal Advocates cites to PG&E's record of underperforming this activity since 2019.[290] For example, in 2021 PG&E only spent $2.655 million in 2021 ($17.872 million less than the forecast).[291] In addition, Cal Advocates contends that new requirements issued by the federal Pipeline Hazardous Materials and Safety Administration (PHMSA)[292] create further uncertainty regarding the forecast for this program. Cal Advocates asserts that PG&E's testimony does not

[288] PG&E Ex-16-E (Rebuttal) at 5-44.

[289] PG&E Reply Brief at 147.

[290] Cal Advocates Opening Brief at 71-72 and 454-456.

[291] Cal Advocates Opening Brief at 120.

[292] 49 CFR Subpart O, Section 192.939 Gas Transmission Pipeline Integrity Management.

support eliminating the ICDMA and concludes that no money should be authorized for this item and the ICDMA should be continued.[293]

We are not persuaded by Cal Advocates. PG&E acknowledges the wide variability in spending for this program. For example, PG&E states even if it spent less than forecast in 2021, it spent $1.1 million more than the 2020 forecast of $5.9 million. Further, PG&E says it incorporated the recent PHMSA interpretation into PG&E's 2023 forecast and that "it is entirely reasonable to expect that PG&E's costs will substantially increase."[294] We find PG&E's explanation reasonable and conclude that there is no need to continue the ICDAMA due to cost uncertainty. In a later Section, we adopt PG&E's recommendation to discontinue the ICDAMA. For this rate period we adopt an estimated cost for ICA digs, explained below. Cost variability, if any, can be tracked in the TIMPBA.

The second disputed issue is cost. TURN recommends $11.829 million for ICDA digs in 2023 based on a reduced per project forecast using the same approach it used for the forecast for ICDA Engineering (HPJ) above. That is, TURN combined 2017-2019 data with 2014-2016 data to calculate a unit cost of $251,953 per project rather than PG&E's $285,503 per dig.[295]

The Commission adopts TURN's forecast for ICDA digs (Expense MAT HPO) of $11.829 million for 2023. We do this for the same reason we did so above for ICDA Engineering (MAT HPJ), because we conclude that a longer period of historical recorded cost data (2014-2019) is likely to be more accurate.[296]

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[293] Cal Advocates Opening Brief at 120 to 121, *citing to* PG&E Ex-16 (Rebuttal) at 5-45.

[294] Cal Advocates Opening Brief at 120-121.

[295] PG&E Ex-16-E (Rebuttal) at 5-44; TURN Opening Brief at 198.

[296] TURN Opening Brief at 200.

3.4.2.5. SCCDA Engineering and Surveys (Expense MAT HPK)

Stress Corrosion Cracking Direct Assessment (SCCDA) engineering and surveys are used to proactively address axial stress corrosion cracking on gas pipelines where the likelihood of stress corrosion cracking has been determined to be low to moderate.[297] PG&E's 2023 forecast for SCCDA engineering and survey expense is $1.971 million.[298] This is for direct assessments on approximately 62 miles of transmission pipeline to address the threat of stress corrosion cracking in high consequence areas during the rate case period.[299] PG&E states that the forecast for SCCDA engineering and surveys is higher for this rate case period because of upcoming regulatory compliance deadlines which did not exist in 2021.[300]

TURN recommends a SCCDA engineering and survey expense forecast of $1.630 million. This is based on the same longer 2014-2019 data series that TURN used for its ECDA and ICDA unit cost estimates, asserting that the shorter period with less projects used by PG&E is less accurate. [301]

Cal Advocates recommends reducing SCCDA Engineering and Surveys – Expense (MAT HPK) by 97% to $0.050 million using an 11-month average of 2021 recorded costs. Cal Advocates explained that, as of late 2021, PG&E had only addressed two stress corrosion cracking threats at a cost of $0.8 million, which is significantly lower than PG&E's $2.5 million forecast for that year.

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[297] PG&E Opening Brief at 156.

[298] PG&E Reply Brief at 152.

[299] PG&E Ex-03 at 5-44.

[300] PG&E Reply Brief at 154.

[301] TURN Amended Opening Brief at 202; PG&E1 Ex-6-E at 5-48.

Further, Cal Advocate argues that PG&E provided an inadequate response to Cal Advocates for all calculations and workpapers to support PG&E's estimate for performing SCCDA engineering and surveys.[302] Cal Advocates also indicated that PG&E failed to supply the record with new information beyond PG&E's workpapers to satisfy Cal Advocates' data requests on the 77 compliance projects in their forecast. Cal Advocates concludes that PG&E's request is unsupported.[303] In response, PG&E states that its estimates are based on the cumulative mileage of specific projects identified in its exhibit and workpapers.

Based on the evidence, the Commission finds PG&E's underperformance in this area is not adequately explained by PG&E's responses to party requests for information, and a reduction to PG&E's request is warranted. We decline to adopt an estimate based 2021 data, however, but believe the longer period recommended by TURN is reasonable. Therefore, the Commission adopts TURN's forecast of $1.63 million for 2023 for SCCDA Engineering and Surveys (Expense MAT HPK) for the same reasons we did so for ECDA, and ICDA above.

3.4.2.6. SCCDA Digs (Expense MAT HPP)

SCCDA Digs involve excavating and exposing pipe segments at selected susceptible locations in covered segments. The exposed segments are evaluated for the severity of stress corrosion cracking.[304] PG&E's 2023 forecast for SCCDA digs is $16.208 million.[305] These projects have federal compliance deadlines within the 2023-2026 period.

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[302] Cal Advocate Opening Brief 67 to 68; PG&E Ex-03 at 5-22.

[303] Cal Advocates Opening Brief at 68.

[304] PG&E Ex-16 (Rebuttal) at 5-50.

[305] PG&E Reply Brief at 154.

TURN recommends a lower forecast of $15.910 million for SCCDA Digs based on arguments similar to those that TURN made regarding SCCDA engineering and surveys (MAT HPK) above.[306] PG&E made the same arguments in response.[307] Just as before, Cal Advocates proposes reducing the SCCDA digs forecast by 94% to $0.898 million based on arguments Cal Advocates made similar to those it did for SCCDA engineering and surveys above. This includes Cal Advocates' argument that PG&E failed to provide sufficient evidence to support its request.[308]

In response, PG&E explains how it identified each project proposed to be addressed in the rate case period, citing specifics regarding the number of proposed digs, project locations, mileage, type of SCC threat, and the compliance due date.[309]

Just as we did above regarding SCCDA Engineering and Surveys, we find that PG&E's underperformance in this area is not adequately explained by their responses to party requests for information and a reduction in PG&E's request is warranted. The Commission adopts TURN's forecast of $15.910 million for 2023 for SCCDA digs (Expense MAT HPP) for the same reasons we did so for ECDA, and ICDA above.

3.4.2.7. TIMP Direct Examination (Expense MAT HPU)

The TIMP direct examination program is a direct assessment sub-program that involves excavating all of a section of pipe, removing the coating, and

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306 TURN Opening Brief at 202.

307 PG&E Reply Brief at 154.

308 Cal Advocates Opening Brief at 67; PG&E Reply Brief at 155.

309 PG&E Reply Brief at 155.

inspecting all pipe surfaces. Due to the full excavation involved, however, it is only suitable for short sections of pipe or where performing above-ground surveys is not feasible.[310] PG&E's 2023 forecast for this program is $23.965 million.[311]

Cal Advocates recommends $10.405 million for TIMP Direct Examination, contending that PG&E's request is excessive and inadequately supported. Moreover, Cal Advocates argues that PG&E's 2023 forecast is inflated because PG&E lists projects with compliance due dates outside the 2023-2026 period.[312]

The Commission finds that PG&E's forecast for the TIMP direct examination program is reasonably based on meeting the accelerated compliance dates driven by the new PHMSA interpretation.[313] Further, while a few projects have compliance deadlines outside the rate case period, we are persuaded by PG&E that their inclusion plausibly ensures their completion by the compliance date and optimizes the use of resources.[314] Thus, the Commission adopts PG&E's 2023 forecast for the TIMP Direct Examination (Expense MAT HPU) program of $23.965 million.

3.4.3. Strength Testing (MWCs HP and 75)

PG&E proposes 749 pipeline strength testing and replacement projects over 175.75 miles during 2023-2026.[315] TURN disputes six strength testing programs based on three issues it applies to all six programs. These three issues

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[310] PG&E-16 at 5-45.

[311] PG&E Reply Brief at 155.

[312] Cal Advocates Opening Brief at 67; PG&E Reply Brief at 155.

[313] PG&E Opening Brief at 155, 160, 209, and 210.

[314] PG&E Reply Brief at 158-156.

[315] TURN Opening Brief at 203.

are: (1) the appropriate disallowance percentage to apply to costs for pipelines installed after December 31, 1955, when those pipelines lack a traceable, verifiable, and complete (TVC) or accurate record of a strength test; (2) the correct cost model based on each party's regression analysis; and (3) including or excluding projects from PG&E's forecast based on compliance deadlines.[316]

We first summarize the purpose and approach for strength testing. We then address the three common issues raised by TURN. We conclude by adopting forecasts for each of the disputed strength testing programs.

First, the purpose and approach for strength testing is as follows. PG&E reports that it conducts hydrostatic strength tests on gas transmission pipelines to assess their integrity and to determine or verify the appropriate maximum allowable operating pressure (MAOP) of liquified and compressed natural gas.[317] PG&E states that it uses an operational risk modeling tool called the TIMP to assess threats on every segment of transmission pipe, evaluate the associated risks, and act to prevent or mitigate these threats. According to PG&E, the TIMP approach for assessing risk is consistent with professional standards and is used to satisfy additional requirements of federal regulations.[318]

PG&E contends that it satisfies the requirements of California and federal regulations by grouping its tests into two types:[319] (1) strength testing for TIMP purposes, and (2) strength testing for non-TIMP purposes (including the less stringent requirement of Pub. Util. Code § 958 of testing as "soon as practicable"). Pipeline sections falling into one of these categories that are too

[316] TURN Opening Brief at 204-208.

[317] PG&E Ex-03 at 5-50 and 5-51.

[318] 49 CFR Part 192 Subpart O; PG&E Ex-03 at 3-6.

[319] PG&E Ex-03 at 5-52 and 5-53.

short to be strength-tested cost-effectively are replaced.[320] When pipelines are out of service to accommodate a hydrostatic test, PG&E provides portable liquified natural gas/compressed natural gas service to customers' equipment.[321] PG&E bases its strength testing and replacement forecast on its analysis of cost and other characteristics of strength testing and replacement projects that were completed during the years 2016-2019.

We now look at the three issues in dispute.

3.4.3.1. Disallowance Percentage

The first disputed issue is the disallowance percentage. PG&E states that it is not seeking to recover costs associated with pipe installed after December 31, 1955, when that pipe lacks an accurate record of a pressure test, consistent with directions in D.12-12-030 and D.16-06-056.[322] Where no such documentation exists for pipeline lengths constructed after December 31, 1955, PG&E's forecasts exclude the cost of pressure testing those pipeline lengths regardless of whether they are pressure tested or whether they are replaced. To determine the percentage of disallowance, PG&E calculates the pipeline mileage lacking documentation as a percentage of total project mileage. Using this methodology, PG&E proposes to disallow 9.22%of the total project costs due to missing pipeline pressure test records.[323]

TURN disputes PG&E's disallowance factor for two reasons. First, TURN argues that PG&E should have excluded 13.84 miles of TIMP strength tests from

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[320] PG&E Ex-03 at 5-51 and 5-53.

[321] When pipelines are out of service to accommodate a hydrostatic test, PG&E provides portable liquified natural gas/compressed natural gas service to customers equipment. PG&E Ex-03 at 5-64.

[322] PG&E Ex-03 at 5-56.

[323] TURN Opening Brief at 203 *citing to* PG&E Ex-03 at 5-54.

PG&E's disallowance calculation because, according to TURN, the disallowance applies to non-TIMP strength tests, not TIMP tests. PG&E agrees that PG&E's original calculation included certain miles that should have been excluded. Adjusting the forecast for this increases PG&E's disallowance factor from 9.22% to 10.01%.[324]

Second, TURN disputes PG&E's methodology to calculate the disallowance factor. Prior to excluding miles of TIMP tests, PG&E estimated the disallowance percentage based on a fixed percentage of total pipeline miles. According to TURN, PG&E's estimate assumes that the relationship between the pipe lacking accurate tests and total pipeline miles is fixed or linear. TURN calculates disallowance percentages on a project-by-project basis and finds that the percentage varies from 0 to 68. According to TURN, this demonstrates that the relationship between disallowed cost and disallowed pipeline mileage is not linear.[325]

Moreover, PG&E argues that TURN's analysis falsely assumes that the strength testing projects for the rate case period are static. PG&E explains that strength testing projects are not static because they may be replaced during the rate case period for a variety of reasons, such as changing risks and system constraints. As a result, PG&E claims that its approach, which relies on mileage estimates rather than specific projects, is more reasonable and likely to be representative of the actual work performed.[326] We are not convinced.

We are persuaded by TURN. PG&E acknowledges that TURN's evidence makes clear that the length of pipe without an accurate record varies

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[324] TURN Opening Brief at 204.

[325] TURN Opening Brief at 205.

[326] PG&E Reply Brief at 161

substantially from pipe to pipe.[327] Given this substantial variability, the Commission adopts TURN's methodology for estimating the disallowance percentage in this rate case.[328]

3.4.3.2. Cost Model for TIMP and Non-TIMP Strength Testing Programs

The second disputed issue is over the cost model. PG&E and TURN both estimate the unit costs for various TIMP and Non-TIMP strength testing programs using cost models based on regression analysis. PG&E's regression analysis results in an R-squared value of 0.735, whereas TURN's regression analysis results in an R-squared value of 0.726.[329] R-squared values measure statistical accuracy.[330]

TURN states that its regression analysis is consistent with PG&E's cost calculator, is based on updated and corrected data, and is based on its project-by-project analysis. PG&E argues for its approach saying TURN's analysis is less accurate because its R-squared value is lower.[331] TURN points out that although its R-square value is lower, it is more accurate because it uses more recent data.[332]

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[327] PG&E Reply Brief at 161.

[328] TURN Opening Brief at 204-207; PG&E Opening Brief at 162-163; PG&E Reply Brief at 160-162.

[329] PG&E Opening Brief at 162.

[330] An "R-Squared value" is the coefficient of determination in statistics. It provides a measure of how well observed outcomes are replicated by the model and ranges from 0 to 1. Generally, the curve fit of a linear regression model is considered to be better as it gets closer to 1. PG&E Ex-03 at 5-71.

[331] PG&E Reply Brief at 162.

[332] TURN Opening Brief at 207.

The parties' R-squared values are substantially similar, and both are over 0.725. This indicates a high confidence in both parties' R-squared values. In fact, this confidence is demonstrated by PG&E arguing for the elimination of its Hydrostatic Testing Balancing Account given that the unit cost R-squared values in this GRC are seven times better than the R-squared value in the last GT&S GRC.[333]

Given better R-squared values here than before, and the substantially similar results between PG&E and TURN, the Commission adopts TURN's cost model for TIMP and Non-TIMP strength testing programs. We do this because TURN's analysis is based on updated and corrected data.

3.4.3.3. Compliance Deadlines

The third disputed issue regards compliance deadlines. PG&E proposes to complete 749 strength testing or replacement projects during this rate case cycle in order to comply with safety regulations. Most of these pipeline projects have deadlines for completion by the end of 2026; however, 91 pipelines have compliance deadlines that are later than December 31, 2026, or are not identifiable because the primary requirement to pressure test is imposed by Pub. Util. Code § 958 with a "soon as practicable deadline."[334] Net of these 91 projects, some of the remaining 658 strength testing or replacement projects proposed during the 2023- 2026 rate case cycle also either have no deadline or a deadline beyond December 31, 2026. There are 84 of those projects.

Of these 84 projects, TURN recommends delaying completion of 65 projects until the next rate case cycle.[335] In support, TURN states that several

[333] PG&E Ex-03 at 5-71 to 5-72.

[334] TURN Opening Brief at 208-209.

[335] TURN Opening Brief at 210-211.

of these projects are for pipelines operating at or above 20% of specific minimum yield strength.[336] TURN contends that the RSE risk score for the non-TIMP strength testing program is 0.1423, which ranks the non-TIMP strength testing program at 207th out of the 247 PG&E programs with risk scores and an extremely low cost-benefit ratio. Due to their extremely low cost-effectiveness and the absence of specific compliance deadlines, TURN recommends delaying the completion of 65 projects. TURN accepts completion of the other 684 projects in this rate case cycle.

In response, PG&E questions whether it can move 65 strength testing projects into the next rate case cycle without compromising its ability to comply with regulatory requirements.[337] For example, PG&E states that federal regulations require re-confirmation of 50% of maximum allowable operating pressure by July 3, 2028.[338] PG&E states it is concerned that moving 65 projects to the next rate case cycle might make it unable to comply with its safety responsibilities because it "would not be able to garner the resources for that much work."[339]

Based on this record, we find that PG&E has not met its burden to demonstrate the necessity and cost-effectiveness for its forecasted 749 strength testing projects. For example, as noted by TURN, PG&E does not state with

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[336] TURN Opening Brief at 210-212.

[337] PG&E Reply Brief at 162-164.

[338] PG&E Reply Brief at 163; 49 CFR 192.624. In particular, 49 CFR 192.624(b)(1) requires utilities "to complete all actions required by this section [192.624] on at least 50% of the pipeline mileage by July 3, 2028."

[339] TURN Opening Brief at 213-214.

sufficient specificity which pipelines meet the conditions for testing by July 3, 2028 (as required by federal regulation), such as the consequence[340] or risk level.

Moreover, we also agree with TURN when TURN points out that PG&E's stated difficulty performing these 65 projects in the next rate case cycle does not support performing these projects now. Rather, there is no evidence that the resources in the next cycle will be inadequate. Accordingly, the Commission finds that it is reasonable for PG&E to perform the undisputed amount of 684 projects (749 minus 65) during this GRC cycle.

We now turn to the six sub-programs disputed by TURN: (1) non-TIMP strength testing capital expenditures; (2) non-TIMP pipeline replacement in lieu of strength testing capital; (3) non-TIMP pipeline replacement in lieu of strength testing expense; (4) TIMP strength testing expense; (5) TIMP replacement in lieu of strength testing expense; and (6) TIMP replacement in lieu of strength testing capital.

3.4.3.4. Non-TIMP Strength Testing (Capital MAT 75U)

In accordance with federal and state regulations, the non-TIMP strength testing sub-program validates the integrity of gas pipelines by strength testing pipelines, including pipelines either (a) lacking a traceable, verifiable, and complete record or (b) needing MAOP reconfirmation.[341] PG&E forecasts $73.325 million for Non-TIMP Strength Testing in 2023.[342]

TURN forecasts a lower amount for non-TIMP strength testing of $59.915 million (2020 dollars) based on the three issues disputed above:

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[340] TURN Opening Brief at 215.

[341] PG&E Opening Brief at 160-161.

[342] PG&E Opening Brief at 161; PG&E Reply Brief at 159.

(1) disallowance percent, (2) use of a different unit cost model, and (3) removal of certain projects based on relevant compliance deadlines.

In the discussion above, the Commission adopted TURN's disallowance factor, cost model, and removal of 65 projects based on compliance deadlines. Consistent with these decisions, the Commission adopts TURN's forecast in 2023 for non-TIMP testing of $59.915 million in 2020 dollars[343] or $61.956 million in 2023 dollars.[344]

3.4.3.5. Non-TIMP Pipeline Replacement in Lieu of Strength Testing (Capital MAT 75R)

When a pipeline replacement is more cost-effective than performing a non-TIMP strength test, PG&E states that it replaces the pipeline under its non-TIMP pipeline replacement program. Pipeline replacement is not an "alternative" assessment methodology, according to PG&E, but rather the wholesale replacement of a pipe instead of performing strength testing.[345] There are two components: capital and expense. The program addressed in this Section is with regard to capital. PG&E forecasts $66.653 million for non-TIMP pipeline replacement in lieu of strength testing capital costs in 2023.[346]

TURN forecasts a lower amount for the non-TIMP pipeline replacement program of $33.741 million (2020 dollars)[347] based on the three issues disputed above: (1) disallowance percent, (2) use of a different unit cost model, and (3) removal of certain projects based on relevant compliance deadlines.

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343 TURN Opening Brief at 212 (Table 23).

344 PG&E Opening Brief at 161 (Table 3-23).

345 PG&E Opening Brief at 165.

346 PG&E Opening Brief at 164.

347 TURN Opening Brief at 212 (Table 23).

In the discussion above, the Commission adopted TURN's disallowance factor, cost model, and removal of 65 projects based on compliance deadlines. Consistent with these decisions, the Commission adopts TURN's forecast for non-TIMP pipeline replacement in lieu of strength testing in 2023 of $33.741 million in 2020 dollars[348] or $36.080 million 2023 dollars.[349]

3.4.3.6. Non-TIMP Pipeline Replacement in Lieu of Strength Testing (Expense MAT JT6)

In addition to capital costs for non-TIMP replacement, PG&E incurs expenses related to these projects.[350] PG&E forecasts $35.443 million in expenses for non-TIMP pipeline replacement in lieu of strength testing in 2023.[351]

TURN forecasts a lower amount for non-TIMP strength testing of $9.728 million (2020 dollars)[352] based on the three issues debated above: (1) disallowance percent, (2) use of a different unit cost model, and (3) removal of certain projects based on relevant compliance deadlines.

Consistent with prior discussion, the Commission adopts TURN's forecast for non-TIMP pipeline replacement in lieu of strength testing in 2023 of $9.728 million in 2020 dollars[353] or $10.622 million in 2023 dollars.[354]

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348 TURN Opening Brief at 212 (Table 23).

349 PG&E Opening Brief at 164 (Table 3-24).

350 PG&E Opening Brief at 165.

351 PG&E Opening Brief at 164.

352 TURN Opening Brief at 212 (Table 23).

353 TURN Opening Brief, at 212 (Table 23).

354 PG&E Opening Brief at 165 (Table 3-25).

3.4.3.7. TIMP Strength Testing (Expense MAT HPF)

In accordance with federal law, TIMP strength tests validate the integrity of pipe that is located in high consequence areas (HCAs), Class 3 and 4 non-HCAs, and potentially in moderate consequence areas (MCAs).[355] PG&E forecasts $19.917 million for TIMP Strength Testing expenses in 2023.[356] While TURN uses a different model, neither TURN nor any other party recommends an estimate lower than PG&E's forecast. Accordingly, the Commission adopts a forecast of $19.917 million for TIMP strength testing (expense MAT HPF)[357] in 2023.

3.4.3.8. TIMP Replacement in Lieu of Strength Testing (Expense MAT HPM)

TIMP replacements are used when a replacement is a more cost-effective option instead of strength testing. There are two components: expense and capital. The program addressed here represents the expense portion of pipe replacements in lieu of TIMP strength testing.[358] PG&E forecasts $4.153 million for TIMP pipeline replacement in lieu of strength testing in 2023.[359]

TURN forecasts a slightly different amount for pipe replacement in lieu of TIMP strength testing based on the use of a different unit cost model. While the Commission adopted TURN's cost model above for the strength testing unit cost, TURN's recommendation for this program is unclear and not sufficiently detailed to be supported. Accordingly, the Commission adopts PG&E's forecast

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[355] PG&E Opening Brief at 166.

[356] PG&E Ex-16-E (Rebuttal) at 5-89; PG&E Opening Brief at 167.

[357] TURN Opening Brief at 212 (Table 23).

[358] PG&E Opening Brief at 167.

[359] PG&E Opening Brief at 168.

of $4.153 million for TIMP pipe replacement in lieu of strength testing expenses (MAT HPM) in 2023.

3.4.3.9. TIMP Replacement in Lieu of Strength Testing (Capital MAT 75Q)

PG&E forecasts $17.899 million for TIMP pipeline replacement in lieu of strength testing in 2023.[360]

TURN forecasts a slightly different amount for pipe replacement in lieu of TIMP strength testing based on the use of a different unit cost model. While the Commission adopted TURN's cost model above for the strength testing unit cost, TURN's recommendation for this program is unclear and not specific. Accordingly, the Commission adopts a forecast of $17.899 million for capital pipe replacement in lieu of TIMP strength testing (Capital MAT 75Q) in 2023.

3.4.4. Vintage Pipe Replacement (Capital MWC 75E)

Approximately 47% of PG&E's GT pipelines were designed, manufactured, constructed, and installed before the advent of California pipeline safety laws in 1961. While age alone does not pose a threat to pipeline integrity, age does play a role because of the type of manufacturing and construction practices that were acceptable at that time – that is, the "vintage" of the pipe.[361]

PG&E proposes to replace 0.72 miles of pipeline in 17 projects in which the pipelines are threatened by a combination of construction defects and outside forces such as land movement.[362] PG&E recommends replacing this pipe because

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[360] PG&E Opening Brief at 169.

[361] PG&E Ex-03 at 5-72.

[362] PG&E Ex-03 at 5-78. The program scope has been revised from the 2019 GT&S Rate Case to only consider for replacement of vintage fabrication and construction threats where they interact with high land movement threats, where bending strain from ILI data is identified, or where we have both landslide and liquefaction threats.

(1) other similar pipelines have failed because of this type of phenomenon, including a recent incident outside of California; (2) the federal Pipeline and Hazardous Materials Safety Administration (PHMSA) has urged gas pipeline operators to evaluate this threat; and (3) industry groups developing best practices have highlighted the importance of addressing the risks created by land movement. PG&E says that the 17 proposed projects include Tier 1 pipelines containing high consequence areas (HCA) and Tier 2 pipelines not in HCA areas. PG&E requests that the Commission authorize capital expenditures for MAT 75E of $10.835 million for 2023.[363] This 2023 forecast is $12.053 million less than the cost recorded for this program in 2020 of $22.888 million.[364]

TURN recommends either (1) eliminating the program, or (2) eliminating all proposed projects which have an associated impacted occupancy count (IOC) of ten or less[365] and exclude carry-over costs. According to TURN, its second recommendation would result in authorizing $3.7 million for 2023.

TURN's primary recommendation is that no money be authorized for this program. TURN bases this on the following: (1) the Tier 1 projects will continue to be assessed every seven-year cycle as required to meet TIMP regulations because they contain HCA mileage, (2) the program is not cost-effective according to its low RSE scores, and (3) PG&E's unit cost includes $1.7 million each year in unrecovered 2021-2022 "closeout costs" from Vintage Pipeline Replacement projects that were authorized in D.19-09-025.

In support, TURN states that if any pipeline shows deterioration in its assessment, it can be repaired at that time. In addition, the Tier 2 projects contain

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[363] PG&E Ex-03-ES at v.

[364] PG&E Ex-03 at 5-80.

[365] TURN Opening Brief at 223.

no HCA mileage and have impacted occupancy counts (IOCs) that are below 10. These pipelines are clearly in rural areas and there are no dwelling units or even recreational facilities nearby. Thus, even in a worst-case scenario, such as a pipeline rupture, the expected loss of life or property damage is reduced.[366] Further, TURN adds that carryover costs are not actual costs associated with the new batch of Vintage Pipeline Replacement projects that PG&E proposes in this rate case cycle. Instead, they are costs that PG&E will incur and pay after the projects from the previous GT&S case are actually brought into service.[367]

In response, PG&E argues that the unit cost forecast for vintage pipeline replacement was based on projects completed between 2015-2019 that met relevant criteria. PG&E states that its forecast includes closeout costs for projects that are expected to come on-line in 2021- 2022. Because these close-out costs will be incurred after the end of the 2019 GT&S rate case period (2019-2022), PG&E argues that it is appropriate to include them in the rates for this GRC because otherwise these costs will not be recovered.

Considering all the parties' arguments, the Commission finds that the scope of the Vintage Pipeline Replacement program continues to address valid potential threats not addressed by PG&E's other pipeline assessment and replacement programs, including those that are the subject of PHMSA advisories.[368] Thus, we reject TURN's recommendation for program elimination.

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366 TURN Opening Brief at 220.

367 TURN Opening Brief at 220 -221.

368 PHMSA Advisory ADB 2019-02: The advisory points out that when an operator discovers a condition covered under the integrity management requirements of 49 CFR 195.452 or if a segment of pipeline is determined to be in unsatisfactory condition per 49 CFR 192.613 [b] (in the context of this advisory, a landslide), that 49 CFR 192.935 and 49 CFR 195.452 (i) require, "…an operator to take additional preventative and mitigative measures to prevent a pipeline

Footnote continued on next page.

In deciding the right size for the program, we note that PG&E has already limited the scope of the program to approximately half of what the Commission approved for 2020. Even within the reduced request, the Commission must continue to consider program cost-effectiveness. TURN's evidence shows the program has low RSEs. The Commission finds that TURN's alternative proposal achieves a reasonable balance between retaining the program to address valid potential threats while considering cost-effectiveness. We exclude carry-over costs because these are not costs related to the authorized projects. Consequently, the Commission adopts TURN's forecast of $3.7 million for MWC 75E in 2023.[369]

3.4.5. Shallow and Exposed Pipe Capital Cost (MAT 75K, 75M, 75T)

PG&E's Shallow and Exposed Pipe Program identifies locations where a pipeline has insufficient ground cover, is vulnerable to damage from third parties, or becomes exposed due to natural forces. Given the safety risks presented by exposed natural gas transmission pipelines, PG&E seeks to prioritize and mitigate these risks. The Shallow and Exposed Pipe Program also addresses risks at water and levee crossings.[370]

PG&E requests that the Commission authorize capital expenditures for this program of $27.808 million for 2023.[371] PG&E developed its forecast by multiplying the number of forecast mitigation locations by the historical average

failure and to mitigate the consequences of a pipeline failure that could affect a high consequence area…if an operator determines there is a threat to the pipeline, such as outside force damage (e.g. earth movement, floods), the operator must take steps to prevent a failure and to minimize the consequences of a failure under these regulations." PG&E Ex-16 (Rebuttal) at 5-69.

[369] PG&E Reply Brief at 165.

[370] PG&E Opening Brief at 172.

[371] PG&E Opening Brief at 173.

cost per project from 2017-2019, plus escalation. This amounts to an increase of $9.397 million over the recorded 2020 level of $18.411 million.[372]

TURN recommends either (1) eliminating this program, or (2) reducing it to $20.485 million. TURN recommends program elimination because (1) it has low RSE scores and is not cost-effective, and (2) PG&E has underspent its authorized funding by an average of 30%.[373] In support, TURN states the low RSEs and benefit/cost ratios reflect the minimal risk reduction benefits that PG&E calculated for this program compared to the program's total cost. For example, according to TURN, the total value of the risk reduction benefit is only $2.05 million, compared to the total cost of $131.52 million, which equates to a program level benefit cost ratio of 0.0156, or less than two cents of benefits per dollar of spending.[374]

In further support, TURN states that PG&E underspent its authorized budget in four of the past five years. TURN asserts that PG&E underspent an average of 30% during the 2016-2020 period, for a total underspend of $34 million. According to TURN, PG&E's request of $27.808 million for 2023 is almost double PG&E's average annual spending over the past five years and is inconsistent with PG&E's practice of underspending.[375]

In response, PG&E's describes how the selection of its mitigation locations using its project or site specific methodology is informed by industry best practices, including those of Pipeline and Hazardous Materials Safety Administration, the California State Lands Commission, and direction from the

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[372] TURN Opening Brief at 233.

[373] TURN Opening Brief at 226.

[374] TURN Opening Brief at 228.

[375] TURN Opening Brief at 233 to 234.

Central Valley Flood Protection Board.[376] PG&E states that such practices requires mitigation of risks based on continual surveillance.[377] PG&E also notes that it has no metrics in its safety performance metrics report for this program to measure its progress. Further, while PG&E acknowledges its underspending, PG&E contends that its underspending is justified by "the fact that these capital costs were spent on higher risk mitigations/controls within PG&E's Pipe Replacement program."[378]

Spending on the Shallow and Exposed Pipe Program is discretionary because it is not required by regulations.[379] Further, we find PG&E has not met its burden to demonstrate that its full request for this program is necessary to provide safe, reliable, and affordable utility service. We find this based on the evidence showing low RSEs, consistent underspending, no metrics in its safety performance metrics report to measure progress, and incomplete support to show that redirecting the authorized capital costs to other projects was justified. Nonetheless, spending on this program is still warranted when conditions needing mitigation are found. The Commission determines the appropriate level of funding for this program by considering the relative cost-effectiveness of the program. As a result, the Commission finds that TURN's alternate proposal of $20.485 million[380] strikes a reasonable balance and adopts a forecast in that amount for MATs 75K, 75M, 75T for 2023.

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[376] PG&E Ex-03 at 5-119 to 5-127.

[377] *See, e.g.,* 49 CFR § 192.613 requires the mitigation of findings from continuing surveillance. PG&E Ex-03 at 5-126.

[378] PG&E Ex-16-E (Rebuttal) at 5-76.

[379] PG&E Reply Brief at 170.

[380] TURN Opening Brief at 226-227.

3.4.6. Public Awareness Program (Expense MAT JT0)

Federal regulations require PG&E to develop and implement public education programs that comply with the American Petroleum Institute's recommended practices.[381] In compliance with these regulations, PG&E has developed a public awareness program with three objectives: (1) increase awareness about the presence of natural gas pipelines; (2) reduce third-party damage to pipelines through education outreach; and (3) promote emergency response readiness.[382]

PG&E's forecast includes funding for a new Global Positioning System (GPS) program that will start in 2023. The GPS Program uses real-time data and motion sensors placed on excavation equipment to monitor an excavator's location and activities. The GPS program includes an automated alert system that notifies utility personnel and the excavator if there is a risk of hitting or digging into a gas pipeline, thereby having the potential to significantly reduce construction site dig-ins.[383]

PG&E forecasts $4.386 million for MAT JT0 in 2023. PG&E's forecast for the Public Awareness Program is an increase of $1.956 million over 2020 recorded costs. PG&E developed this forecast by starting with the 2017-2019 three-year average of recorded data and adding $1.9 million annually for the GPS-based excavation equipment motion sensing device program.[384] PG&E

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[381] 49 CFR § 192.616 requires utilities to develop and implement public education programs that comply with American Petroleum Institute's (API) Recommended Practice 1162, 1st Edition (RP 1162).

[382] PG&E Opening Brief at 174.

[383] PG&E Opening Brief at 175.

[384] PG&E Ex-03 at 5-106 to 5-107.

anticipates that the new GPS-based program will ramp up over the 2023-2026 period (from $0.845 million in 2023 to $2.465 million in 2026) and uses the projected four-year annual average in its forecast for 2023.[385]

TURN recommends a reduction of 35%, to an authorized level $2.932 million in 2023. In support, TURN's evidence summarizes PG&E's authorized and annual spending on the public awareness program and shows that PG&E underspent its authorized funding for Public Awareness in every year from 2016- 2020 by an annual average of 35%. Based on this data, TURN states that its recommended $2.932 million in 2023 is 21% higher than 2020 recorded of $2.430 million, and 32 higher than the 2017-2019 recorded average of $2.218 million.[386] TURN claims its recommendation accounts for the new GPS-based program that PG&E intends to rollout from 2023-2026.

Based on this evidence, the Commission adopts a forecast for MAT JT0 of $3.063 million total for 2023, which we derive as follows. We take underspending into account by using the three year average of $2.218 million (which PG&E acknowledges recognizes its underspending).[387] We are unable to use PG&E's estimate of an additional $1.9 million per year for the GPS-based program, however, because PG&E does not provide sufficiently detailed and compelling information to support either its estimate of an average of $1.9 million per year or how the new program will ramp up over four years. The GPS component is reasonable, however, and we include $0.845 million in 2023 (the estimated funding for 2023), thereby totaling $3.063 million in 2023 for MAT JT0.

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[385] TURN Opening Brief at 223.

[386] TURN Opening Brief at 223-226, and 224 (fn. 664).

[387] PG&E Opening Brief at 175, Reply Brief at 167 -168.

3.4.7. Balancing and Memorandum Accounts

There are seven Balancing and Memorandum Accounts discussed in PG&E's application, of which the proposed changes for two are uncontested – the Hydrostatic Testing Balancing Account (HT BA) and the Root Cause Analysis Memorandum Account (RCA MA). We adopt the uncontested changes. Changes to the five disputed accounts are discussed below.

3.4.7.1. ILI Accounts (ILIBA and ILIMA)

The In-line Inspection Balancing Account (ILIBA) and the ILI Memorandum Account (ILIMA) were established by the Commission in the 2019 GT&S rate case.[388] The ILIBA is a one-way balancing account that records capital costs for the 48 Traditional ILI Upgrade projects adopted for the rate case period. The ILIMA tracks both Traditional ILI Upgrade capital costs and ILI expense costs related to work for Traditional ILI Upgrade projects and Traditional ILI inspection in excess of the 48 ILI upgrade projects authorized in the GT&S rate case as well as ILI reassessment costs.[389]

These accounts were adopted in the 2019 GT&S Rate Case primarily to address concerns that PG&E would not be able to complete more than its forecast of 18 ILI Upgrade projects per year. The Commission set the authorized number of ILI Upgrades at 12 but provided PG&E with the opportunity to do more and record these costs in the ILIMA.

PG&E proposes to eliminate the ILIBA and ILIMA because it proposes to perform 12 ILI Upgrades per year, consistent with the Commission's direction. Therefore, PG&E contends that the ILIBA and ILIMA are no longer needed.

[388] D.19-09-025 at 330

[389] D.19-09-025 at 331, OP 63.

Along with eliminating both accounts, PG&E recommends that costs associated with initial runs, re-assessments and any associated repairs would be accounted for in the TIMPBA because these costs relate to a TIMP program.[390] PG&E states that the accounts are redundant[391] and that the TIMPBA is the better place to address all ILI related expenses.[392]

Cal Advocates opposes PG&E's plan to eliminate either the ILIBA or ILIMA because they return underspending to ratepayers and allow for tracking.[393] TURN agrees with Cal Advocates' opposition to eliminating the ILIBA. TURN states that this is based on evidence that PG&E continues to complete fewer ILI Upgrade projects than authorized, averaging only nine projects per year for 2016-2021.[394]

TURN, however, agrees to the elimination of the ILIMA because, in TURN's view, traditional ILI Upgrade projects are not cost-effective.[395] In addition, TURN recommends that PG&E demonstrate project reasonableness, including the RSE and benefit-cost ratio associated with the individual transmission pipelines that PG&E proposes to upgrade.[396]

The Commission finds that PG&E's history of completing fewer ILI Upgrades than forecast continues to support retaining the ILIBA as a one-way balancing account so that underspending is returned to ratepayers. Accordingly,

[390] PG&E Opening Brief at 179-182.

[391] PG&E Ex-16 (Rebuttal) at 5-84.

[392] PG&E Ex-16 (Rebuttal) at 5-85.

[393] Cal Advocates Ex-02 at 37, lines 12 to 17.

[394] TURN Reply Brief at 87 to 88; TURN Ex-04 at 5-6.

[395] TURN Ex-04 at 22.

[396] TURN Reply Brief at 88 to 89.

PG&E's request to eliminate the ILIBA is denied. The Commission is persuaded, however, that it is reasonable to eliminate the ILIMA because the number of ILI upgrades is determined in this GRC to be four. In addition, we decline to adopt TURN's recommendation to require a post-decision compliance obligation when recording costs into the ILIBA because a reasonableness review is always available at the time of reconciling the balance in the ILIBA.

3.4.7.2. TIMP Accounts (TIMPBA and TIMPMA)

The Transmission Integrity Management Program Balancing Account (TIMPBA) was established in the 2019 GT&S rate case to track TIMP related costs in a one-way balancing account. The TIMP Memorandum Account (TIMPMA) was established in the 2015 GT&S rate case to track any TIMP costs not included in PG&E's forecast that are "associated with any new transmission integrity management statutes or rules, or new or changed interpretation by a regulatory body of transmission or integrity management statutes or rules."[397]

In this proceeding, PG&E proposes converting the TIMPBA to a two-way balancing account and eliminating the TIMPMA. Alternatively, if the TIMPBA remains a one-way balancing account, PG&E proposes keeping the TIMPMA and modifying it so that it tracks all costs above adopted amounts related to existing TIMP regulations as well as costs associated with new TIMP regulations. PG&E proposes structuring the two-way TIMPBA so that all costs above or below the authorized amount would be trued up annually through a Tier 2 Advice Letter. However, for costs greater than 135% of the adopted amount, PG&E proposes recording these costs in a separate subaccount and filing a separate application for recovery of these costs.

[397] PG&E Opening Brief at 176; PG&E Ex-16 (Rebuttal) at 5-79.

In support of its proposals, PG&E contends that eliminating the TIMPMA and converting the TIMPBA into a two-way balancing account would reduce the current administrative complexity involved in maintaining a balancing account and a memorandum account along with the necessary and required reviews.[398] If PG&E's proposal to convert the TIMPBA to a two-way balancing account is not adopted, however, PG&E proposes that the Commission approve an alternative proposal of expand the TIMPMA to include TIMP costs above the adopted amounts.[399]

In further support, PG&E claims that circumstances have changed since the last two rate cases were decided. PG&E states that the Commission should consider the following reasons for changing the structure of these accounts: "1) TIMP costs are mandatory compliance costs that are uncertain and difficult to forecast; (2) recent adoption of two-way balancing account treatment for other areas of gas with uncertain costs such as storage and for difficult-to-forecast electric system hardening costs support a two-way balancing account; (3) consistency with the TIMPBA accounts adopted for Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E); and (4) administrative efficiency and regulatory review."[400]

TURN and Cal Advocates oppose both proposals as the Commission has rejected similar requests in the last two rate cases.[401] Cal Advocates contends that none of PG&E's arguments support changing the current structure of PG&E's

[398] PG&E Opening Brief at 176.

[399] PG&E Opening Brief at 179.

[400] Cal Advocates Opening Brief at 117 *citing to* PG&E Ex-03, Gas Operations Chapters 1-5S at 5-15:25 to 5-16:2.

[401] PG&E Opening Brief at 176 to 177.

TIMPBA and TIMPMA for the following reasons: (1) the Commission already recognized the need for PG&E to address any uncertainty resulting from evolving regulatory developments by allowing PG&E to establish the TIMPMA, (2) the current structure for tracking TIMP-related expenditures is appropriate even when considering recent adoption of two-way balancing account treatment for other areas, and (3) the Commission found unpersuasive the previously raised arguments by PG&E that a two-way balancing account for TIMPBA is consistent with SoCalGas's and SDG&E's approaches and facilitates administrative efficiency and regulatory review.[402]

Upon review of the current structure and the parties' arguments, we do not find that circumstances have changed sufficiently to alter the structure of either account. Rather, the Commission finds that the current structure continues to be a reasonable method for ensuring the PG&E can continue to recover just and reasonable costs incurred to comply with unidentified potential regulation changes that impact the scope of TIMP work. Accordingly, the Commission denies PG&E's proposals for changing the TIMPBA and the TIMPMA.

3.4.7.3. ICDA Memorandum Account

The Internal Corrosion Direct Assessment Memorandum Account (ICDAMA) was adopted by the Commission in the 2019 GT&S Rate Case to track recorded ICDA expenses for the 2019-2022 rate case period. It was adopted in 2019 primarily to address concerns that PG&E had not completed ICDA work authorized in the 2015 GT&S rate case period but had diverted the money to instead fund more TIMP strength tests. According to PG&E, however, it has now completed the units of ICDA work authorized in the 2019 GT&S Rate Case, thus

[402] Cal Advocates Opening Brief at 116-119, *citing to* D.19-09-025 at 159.

eliminating the need for the ICDAMA. Since the basis for establishing and maintaining this memorandum account is no longer applicable, PG&E proposes eliminating the ICDAMA. PG&E's proposal includes allowing the ICDA recorded costs to flow through the TIMPBA as originally intended, given that these costs are Subpart O TIMP-related expenses.[403]

Cal Advocates supports the continued use of the ICDA memorandum account. In support, Cal Advocates points to the continued significant uncertainty associated with the new PHMSA interpretation, as well as PG&E's history of "underperforming."[404]

Cal Advocates' arguments, however, do not take into account the practicality of allowing ICDA recorded costs to flow through the TIMPBA. The Commission finds that review of ICDA recorded costs through a separate memorandum account is no longer necessary. Accordingly, the Commission discontinues the ICDAMA.

3.5. Gas Facilities

This Section addresses PG&E's forecasts related to three Gas Transmission and Distribution (GT&D) aspects of PG&E's business, (also referred to as Facilities): compression and processing, measurement and control, and Compressed Natural Gas (CNG). These assets include compression and processing facilities, gas regulation stations, and CNG stations.[405]

Of the nine gas distribution and GT&D expense categories related to these facilities, only three are disputed. Similarly, for the 17 gas distribution and GT&D

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[403] PG&E Opening Brief at 182.

[404] Cal Advocates Opening Brief at 121; D.19-09-025, Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service, at 137 to 139.

[405] PG&E Opening Brief at 183.

capital categories, only five are disputed. The eight disputed categories are discussed in three subject areas below followed by documentation of the scope of undisputed programs.[406] The three subject areas are: (1) GT Routine C&P Program, (2) Brentwood Terminal Rebuild, and (3) GT and GD M&C Station OPP Enhancements Program.

3.5.1. GT Routine C&P Program (Expense MAT JTY)

We adopt $8.263 million in 2023 for the Gas Transmission (GT) Routine Compression & Processing (C&P) Expense Program (MAT JTY) for the reasons explained below.

This program includes projects that arise during normal operation of C&P facilities that must be performed to maintain current levels of service and reliability. PG&E states typical projects include repair of malfunctioning equipment and instrumentation, compressor unit overhauls, inspection and testing of asset components, and modifications to address equipment safety or performance issues.[407]

PG&E forecasts $10.013 million[408] for this program in 2023, which is an increase of $2.192 million over 2020 recorded costs of $7.821 million. PG&E based its forecast on the three-year average of 2018-2020 recorded costs with escalation after making one adjustment to remove historical costs for the Pleasant Creek Storage Facility because of planned decommissioning in 2022.[409]

[406] PG&E Opening Brief at 184.

[407] PG&E Opening Brief at 185.

[408] PG&E Opening Brief at 185.

[409] TURN Opening Brief at 235.

TURN recommends a forecast for MAT JTY of $8.263 million, which is $1.750 million less than PG&E's request. TURN's proposal is based on using the last recorded year of 2020. In support, TURN asserts (1) PG&E's recorded costs for MAT JTY declined each year over the period PG&E averaged, and (2) in D.04-07-022, the Commission determined that if recorded expenses in an account have shown a trend in a certain direction over three or more years, the most recent point in the trend, which is 2020 in this case, is an appropriate base estimate for the test year.[410]

In response, PG&E argues that (1) 2020 is not a representative year due to COVID-19 related delays from pausing non-essential work, (2) there is some variation in costs expected year-over-year depending on the type of repair, replacement projects, and the facility where work is performed, (3) PG&E's use of a historical average for forecasting programmatic work accounts for year-over-year fluctuations and provides a predictable trend of the expected future level of work, and (4) D.04-07-022 states that an average of recorded expenses over a period of time is reasonable as the base expense where there are significant fluctuations in recorded expenses or where there are external forces beyond the control of the utility.[411]

We are not persuaded by PG&E. After careful review, the Commission finds that fluctuations in the 2018-2020 recorded expenses do not justify using the average instead of the last year. Rather, the expenses over these three years consistently declined. The Commission finds the 2020 recorded cost to be the most known and measurable amount consistent with D.04-07-022 and a

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[410] D.04-07-022, *Opinion on Base Rate Revenue Requirement and Other Phase 1 Issues* (July 16, 2004) at 15 to 16, *quoting from* D.89-12-057; TURN Opening Brief at 235-238.

[411] PG&E Reply Brief at 174-175.

reasonable basis for the 2023 forecast. Accordingly, the Commission adopts a forecast for 2023 of $8.263 million.

3.5.2. Brentwood Terminal Rebuild (Capital MAT 765)

We adopt $8.711 million in 2023 capital expenditures for the Brentwood Terminal Rebuild project and require that PG&E file a Tier 2 Advice Letter as described below if PG&E seeks Commission consideration of additional funding.

The Brentwood Terminal Rebuild project will perform work to upgrade and rebuild aging and obsolete equipment at three gas terminals in Milpitas, Antioch, and Brentwood.[412] The GT measurement and control terminal upgrades program includes two types of work: (1) routine terminal upgrades at all three terminal stations including regular upgrades and maintenance to maintain reliability of the GT system, and (2) a phased approach for rebuilding the Brentwood Terminal.[413]

PG&E forecasts $17.422 million[414] in 2023 capital expenditures for the Brentwood Terminal Rebuild. PG&E derived the 2023 test year forecast by dividing the total forecasted cost for the terminal rebuild by the four years of the GRC cycle.[415] According to PG&E, the work includes four phases that will be operative in sequence before construction starts on the subsequent phase.[416]

TURN opposes inclusion of the Brentwood Terminal Rebuild in this GRC because (1) PG&E has not provided used and useful dates for any of the four

[412] PG&E Ex-16 at 6-11.

[413] PG&E Ex-16 at 6-11.

[414] PG&E Ex-03, WP at 6-32 (Table 6-23).

[415] PG&E Opening Brief at 187; TURN Opening Brief at 239.

[416] PG&E Ex-16-E at 6-13.

project phases, and (2) PG&E failed to spend the authorized amounts in prior years.[417]

In response, PG&E states that this complex project consists of phased construction that is scoped and sequenced so that one phase is completed before starting construction on the subsequent phase. Based on this, PG&E asserts that it made a reasonable assumption that the total project capital spending forecast be allocated equally over four years (2023-2026) for purposes of modeling the operative date.[418] PG&E also states that its spending less than authorized amounts in 2019 and 2020 was due in part to COVID-19 related delays and work requirements. PG&E asserts that it ramped up the work on the Brentwood Terminal Rebuild project in 2021 to forecast completion of the work by 2022.[419]

TURN does not disagree with the necessity of the work forecasted for the Brentwood Terminal Rebuild. The Brentwood terminal is a critical pressure control facility that, if not rebuilt timely, will create safety risks to the public and impact the reliability of gas service.[420] Nonetheless, TURN recommends not including funding for this rebuild in this GRC to protect ratepayers from delays and underspending.[421]

We agree with TURN. Previously authorized amounts have been underspent and project timing has been uneven. The Commission finds it reasonable to protect ratepayers from underspending and timing issues by approving 50% of the requested $17.422 million for the initial phase of the

[417] TURN Opening Brief at 239.

[418] PG&E Reply Brief at 176.

[419] PG&E Reply Brief at 176-177.

[420] PG&E Reply Brief at 175-176.

[421] TURN Reply Brief at 52-53.

project. PG&E may request funding for the remaining phase through one or more Tier 2 advice letters based on PG&E (1) verifying the work has been completed, and (2) providing a detailed scope of work with timelines for completing the remaining phases. Accordingly, the Commission adopts a forecast of $8.711 million in 2023 capital expenditures for the Brentwood Terminal Rebuild and requires PG&E file a Tier 2 advice letter as described above for the Commission to consider additional funding.

3.5.3. GT and GD M&C Station OPP Enhancements Program

This decision first briefly summarizes the OPP Enhancements Program. This provides necessary background information to address the four disputed issues.

PG&E states it designed the gas transmission and distribution Measurement and Control (M&C) Station Overpressure Protection (OPP) Enhancements program to mitigate large overpressure (OP) events due to equipment-related failure at regulator stations. According to PG&E, the industry has found that certain automatic regulator stations, referred to as pilot-operated, have a higher likelihood of overpressure events compared to other M&C station types. These pilot-operated stations can fail when affected by contaminants in the system.

PG&E asserts that the initiatives it is pursuing under its M&C Station OPP program address certain failure modes of GT and GD stations. The initiatives include: (1) installing filters for pilot-operated regulator stations; (2) performing system planning studies, pilot studies, and program management; (3) including evaluation and test modifications to the existing regulation devices on the low pressure (LP) regulator stations to isolate the station during over– and under-pressure scenarios; (4) retrofitting pilot-operated stations with automatic shut-off valves or, if required, other technologies and relief valves; and (5) including reconstruction of Large Volume Customer Meter (LVCM) facilities that are inconsistent with current design standards and operating conditions.[422]

TURN recommends eliminating this program.[423] Before addressing the details of the four specific forecasts in dispute, two topics at the center of these disputes are discussed first: (1) operational benefits, and (2) risk.

Regarding operational benefits, PG&E claims its GT and GD M&C Station OPP Enhancements Program is designed to prevent overpressure events due to equipment failure at pilot-operated gas regulator stations. Overpressure events that occur if the primary OPP regulator fails can result in loss of containment and, with ignition, result in significant injuries, fatalities, loss of service, and/or equipment damage. PG&E claims that four factors drive its forecast for this program.[424]

First, PG&E performed investigations of large overpressure events PG&E experienced from 2011 to the present to determine the cause and to examine mitigations. Second, PG&E collaborated with the industry to review overpressure events in other areas of the country, such as the Merrimack Valley, Massachusetts overpressure event in 2018. Third, PG&E reports that its practice of installing secondary overpressure protection devices is recognized as one of the leading practices in reducing the possibility of a gas overpressure event. For example, PG&E states that it successfully installed devices on other stations called slam shut devices (i.e., valves that automatically shut off gas if pressure

[422] PG&E Opening Brief at 190-191.

[423] TURN Opening Brief at 258.

[424] PG&E Opening Brief at 193-194.

rises above a certain threshold). Fourth, a federal act was passed in 2020 to protect and enhance the safety of pipeline infrastructure, resulting in a Pipeline and Hazardous Materials Safety Administration (PHMSA) rulemaking that would require operators to prevent and mitigate overpressure events using appropriate secondary OPP devices. PG&E contends that its OPP program is consistent with this pending rulemaking.

Regarding risk, PG&E states that its proposed overpressure protection enhancement program is needed to address a significant portion of remaining pilot-operated facilities that carry a risk of Large Overpressure Event Downstream of Gas M&C Facility (LRGOP).[425] PG&E ranks the relative cost-effectiveness of this LRGOP risk as the second lowest baseline risk score of all the RAMP risks. The Commission's Safety Policy Division explained that the baseline risk is low because "the system is designed to prevent overpressure of the pipelines."[426]

TURN argues that, since PG&E began this program in 2017 and has addressed 50% of the targeted assets by the end of 2022, PG&E should have been prioritizing the highest-risk locations first. As a result, TURN contends that there is relatively little LRGOP risk in lower-risk locations left to mitigate in this rate case period.[427]

In response, PG&E states that it considered RSE scores as part of its prioritization process,[428] but the station OPP program is not based on RSEs. Instead, it is based on quantitative and qualitative analysis of large OP events,

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[425] PG&E Opening Brief at 86 and 195.

[426] TURN Opening Brief at 252 to 253.

[427] TURN Opening Brief at 252-253.

[428] PG&E Reply Brief at 182.

causal evaluations, corrective actions, and industry best practices,[429] discussed above. However, industry best practices and pending rulemakings do not determine the pace at which the OPP enhancements program should be completed, according to PG&E.

With this background we now turn to the four specific disputed components of the OPP Enhancements Program. These four are: (1) expense and capital costs, (2) high-pressure regulator program, (3) Tionesta compressor replacement, and (4) Los Medanos compressor replacement.

3.5.3.1. Expense and Capital Costs

The Commission adopts neither expense nor capital funds for the OPP Enhancements Program for the reasons explained below.

The GT and GD M&C Station OPP Enhancements Program involves both expense and capital programs. The expense program (MATs FHQ and JTX) includes installing pilot filters to reduce the likelihood of pilot-operated regulator or monitor- failure due to sulfur; and performing system planning studies, pilot studies, and program management. The capital program (MATs 50N and 76G) includes retrofitting pilot-operated type stations with slam shuts or, if required, alternate technologies and relief valves. For GD, PG&E's 2023 forecasts are $1.807 million for expense (MAT FHQ), and $19.576 million for capital (MAT 50N). For GT, PG&E's 2023 forecasts are $1.073 million for expense (MAT JTX), and $41.372 million for capital (MAT 76G).[430]

As mentioned above, TURN recommends eliminating this program due to the very low cost-effectiveness of the program related to its low-risk reduction

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[429] PG&E Reply Brief at 183.

[430] PG&E Reply Brief at 177.

benefits. PG&E maintains, however, that the program is justified by its operational benefits, which PG&E claims TURN failed to recognize.[431]

Considering both the operational benefits and the cost-effectiveness of the risk reduction benefits, the Commission finds that the operational benefits and risk reduction benefits do not support continued funding of this program in this GRC. Given that the riskier assets were addressed in the first phase of this program, continued funding, if any, can be addressed in a future GRC. Accordingly, the Commission adopts zero funding for MATs FHQ, JTX, 50N and 76G for this rate case period.

3.5.3.2. High-Pressure Regulator (HPR) Program (Capital MWC 2K)

PG&E requests $17.853 million for this program in 2023. For the reasons explained below, however, the Commission does not authorize funding for this program but authorizes $17.853 million to be devoted to the Alternate Energy Program.

PG&E reports that it uses high-pressure, spring-operated regulators (HPRs) in district regulator stations that serve areas of low demand, including individual customers, mostly in rural areas. According to PG&E, the HPR program addresses gas leaks and the condition of HPR facilities. PG&E explains that the scope of the program includes all HPR-type facilities, including Farm Tap HPR sets and HPR-type district regulator stations.

PG&E states that HPRs are addressed by this program through several different options. Where possible and cost-effective, HPR units will be removed and eliminated from the system in lieu of replacement so subsequent maintenance will not be required. Alternatively, HPR units may be rebuilt or

[431] PG&E Reply Brief at 178-181.

updated to an acceptable design configuration or converted to a different district regulator station where appropriate. An additional option, according to PG&E, is to convert the HPR customer to a non-natural gas alternative source and then remove the HPR and associated facilities.[432]

PG&E reports that the HPR program has existed for a decade and is now approaching completion. There are still about 400 HPRs that need to be replaced, according to PG&E. PG&E's forecast of $17.853 million in 2023 is based on replacing 100 HPR units each year for the 2023-2026 period. PG&E states that its 2023 forecast for the HPR replacement program is less than half the amount recorded in 2020 because PG&E is ramping down this program. At the pace of replacing 100 HPRs per year, the program will be effectively completed in 2026.

The Commission is not convinced that PG&E has met its burden of proof to justify funding this program. The Commission first approved replacing HPRs when a 2011 report documented that the majority of leaks on the transmission system were on HPR facilities. The Commission authorized this program, however, without the benefit of RSE analysis. TURN recommends discontinuing funds for the HPR program based on its lack of cost-effectiveness. The Commission agrees with TURN that the forecast cost for completing overpressure protection enhancements at all pilot-operated regulator stations in the next four years is not supported by a cost-effective mitigation benefit.

TURN also asserts that PG&E should now address relatively lower-risk HPR assets compared to the relatively higher-risk assets it targeted in the early years of the program. PG&E responds that the HPR mitigation program was established to address all HPRs that have age and other risks, not just a subset of

[432] PG&E Opening Brief at 196-198.

high-risk assets. The record, however, shows that PG&E failed to provide evidence regarding age or useful life of the approximately 400 remaining HPRs. Thus, the Commission is unable to judge the merits of the program based on asset age or useful life. Further, the Commission is persuaded by TURN that PG&E would have reasonably addressed higher-risk assets first, and the program is now targeted at relatively lower-risk assets.

Gas rates are now higher than in 2011 when the HPR program was first authorized, and there is growing interest in transitioning customers from gas to electric service where reasonable. As PG&E stated, an additional option for the HPR program is to convert the HPR customer to a non-natural gas alternative source and then remove the HPR and associated service facilities.[433]

Accordingly, in light of the affordability challenges posed by PG&E's overall GRC proposal and the arguments regarding long-term gas planning discussed above, the Commission does not authorize funds for replacing the remaining HPRs at this time. We do, however, authorize diversion of funds forecasted for the HPR Program to the Alternate Energy Program consistent with the process established for using such funds discussed in Section 3.12.14. Thus, the Commission adopts zero funding for the MAT 2K HPR Program for 2023-2026 and allocates $17.853 million to the Alternative Energy Program.

3.5.3.3. GT C&P Compressor Replacements and Retirements: Tionesta Compressor Replacement (MAT 76X)

PG&E requests $23.318 million to replace the Tionesta compressor station. The Commission denies this request for the reasons explained below.

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433 PG&E Opening Brief at 196-198.

As background to this issue, PG&E describes its gas transmission (GT) compression and processing (C&P) Compressor Replacements and Retirements Program as focusing on the management of PG&E's fleet of 41 compressor units installed at stations located in its GT pipeline system and underground gas storage facilities. The program includes both compressor replacements and retirements. Approximately 65% of the units in PG&E's compressor fleet are at or over 40 years old, according to PG&E. Compressor replacements focus on facilities typically in response to a specific driver (such as age, obsolescence, change in regulatory requirements, or lack of service or spare parts from manufacturers). Compressor retirements focus on the removal of facilities that are no longer required for system operation and that results in a more efficient operation of the gas system. Together, compressor replacement and retirement initiatives mitigate equipment-related threats and risks that can adversely impact gas system operations through the loss of service, loss of operating flexibility and reliability, and inability to meet evolving industry and environmental regulations.[434]

PG&E's 2023 GRC forecast for MAT 76X includes two projects: (1) the Tionesta Compressor Station Retirement, and (2) the Los Medanos K-1 Compressor Replacement. This Section addresses the Tionesta Compressor Station Retirement.

In the 2019 GT&D rate case, PG&E proposed replacing the Tionesta K-1 compressor unit. However, the results of the system planning studies conducted in 2020 changed PG&E's long-term strategy. In this GRC, PG&E now does not seek to replace but recommends retirement of the Tionesta facility in 2025. PG&E

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[434] PG&E Opening Brief at 199-200.

describes the retirement of the Tionesta facility as including two major activities: (1) removal of the Tionesta equipment, structures, and piping; and (2) conversion of the site to an M&C Complex station facility with remote controlled, main Line valves.[435]

PG&E forecasts a total capital expense of $23.318 million for the Tionesta Compressor Station Retirement project for the 2023 GRCs period. The cost of retirement is forecast over a three-year period and includes $9.184 million, $9.413 million, and $4.720 million in 2023, 2024, and 2025, respectively.[436]

TURN recommends disallowing PG&E's forecast for retiring the Tionesta Compressor Station because TURN believes PG&E's request is comparable to a second request for funding for "deferred work" that triggers the requirements of the Deferred Work Settlement (DWS).[437] According to the DWS, PG&E must demonstrate additional facts to justify funds for deferred work, when the following conditions arise.

1. The work was requested and authorized based on representations that it was needed to provide safe or reliable service.
2. PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and
3. PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.[438]

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[435] PG&E Opening Brief at 205.

[436] PG&E Ex-03-ES at WP 6-38, line 2.

[437] TURN Opening Brief at 206.

[438] TURN Opening Brief at 93; PG&E Opening Brief at 57 to 58; D.20-12-005, *Decision Addressing the Test Year 2020 General Rate Case of Pacific Gas and Electric Company* (December 3, 2020) at 37.

TURN argues that PG&E's request for funds to retire the Tionesta compressor meets these conditions. PG&E responds by asserting that application of the DWS requirements is inappropriate because the third condition is not met (i.e., PG&E no longer claims "that the curtailed work [replacement] is necessary"). Rather, PG&E claims that replacement is not the same as retirement, and the funding authorized for replacement was reasonably allocated to other necessary projects.[439]

The Commission is not convinced. The evidence shows that PG&E is in this GRC proposing the same or similar removal of the Tionesta equipment, structures, and piping that it did in the 2019 GRC. Given that the Commission already approved funds to remove the Tionesta compressor and PG&E is requesting funds for the same work again, further application of the DWS principles described above is required to demonstrate the reasonableness of this request.

The DWS requires PG&E to describe how the specific funding request is consistent with the three principles identified above.[440] After initially denying that a deferred work showing is required, PG&E stated that the adopted funding in the 2020 proceeding was not spent on Tionesta compressor replacement and that it was reallocated to other work in the gas operations portfolio.[441] This explanation does not demonstrate the reasonableness of any alternate work PG&E performed using the already authorized $38.7 million for replacing the

[439] PG&E Reply Brief at 195-198.

[440] D.20-12-005, *Decision Addressing the Test Year 2020 General Rate Case of Pacific Gas and Electric Company* (December 3, 2020) at 324-326; TURN Ex-19-Attachment 1, Settlement Agreement, Section 5.2 at 36-37.

[441] PG&E Reply Brief at 198.

Tionesta compressor. The amount of $23.318 million requested to remove and convert the Tionesta compressor facility in this GRC cycle is more than covered by the $38.7 million PG&E already received to remove and replace it. Accordingly, PG&E's forecast for a total capital expenditure of $23.318 million for the Tionesta Compressor Station Retirement project for the 2023 GRC period is denied.

3.5.3.4. GT C&P Compressor Replacements and Retirements: Los Medanos Compressor Replacement (MAT 76X)

The Commission authorizes PG&E's request of $50.980 million in the 2023 GRC period for one compressor replacement project at the Los Medanos Storage Facility. That project is identified as Los Medanos K-1. To explain this result, this decision first describes the facility. The decision must then briefly trace the project's history and Commission treatment over the last few rate proceedings in order to put the decision in context.

Los Medanos K-1, a Cooper Bessemer GMVM V-12 (Quad) unit installed in 1981, is considered by PG&E to be obsolete. According to PG&E, there were few installations of this model compressor, technical support from the original equipment manufacturer (OEM) is declining, and there has been a notable cost increase in OEM replacement parts. PG&E forecasts a total capital expenditure of $50.980 million for the Los Medanos K-1 compressor replacement project for the 2023 GRC period, including costs to replace an obsolete compressor, replace associated equipment, install a compressor building, and modify any ancillary systems that must be upgraded to accommodate the new unit.[442]

[442] PG&E Ex-03-ES at WP 6-38, line 3.

The relevant Commission treatment starts in 2016, when the Commission authorized PG&E to recover $57.032 million for the Los Medanos compressor station upgrade project and $54.1 million for the Burney compressor upgrade project.[443] The Los Medanos compressor ultimately was not upgraded due to PG&E's decision to pursue the Natural Gas Storage Strategy (NGSS), so PG&E did not spend funds on the Los Medanos project at that time.[444]

In the 2019 proceeding,[445] TURN challenged the reasonableness of a $16.1 million cost overrun on the Burney project. But the Commission found that PG&E had justified the increased costs. It also found that $4.95 million of the cost overruns should have been attributed to PG&E's Physical Security program instead. In effect then, the Commission approved a net cost overrun of $11.15 million for the Burney project ($16.1 million minus the $4.95 million reclassified as Physical Security).[446] There was no deferred work issue raised in that case with respect to the Los Medanos compressor upgrade because, at that point, PG&E stated it was intending to cease operations and requested no funds for that project.

In this rate case, PG&E is proposing to retain the Los Medanos field, while requesting $50.980 million of capital over this rate case period for upgrading the

443 D.16-06-056, Decision Authorizing Pacific Gas and Electric Company's 2015-2018 Revenue Requirement for Gas Transmission and Storage Services and Adopting Interim Rates (June 23, 2016).

444 TURN Opening Brief at 247-248.

445 D.19-09-025 Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service (September 12, 2019) at 99–102.

446 D.19-09-025 Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service (September 12, 2019) at 99–102.

compressor. This upgrade, however, was arguably already funded at $57.032 million in D.16-06-056.

TURN recommends that PG&E's request be disallowed because: (1) PG&E has not provided the required showing consistent with DWS, and (2) $11.2 million was used to cover the cost overruns on the Burney compressor station project, leaving $45.9 million of the amount adopted for the Los Medanos compressor replacement unaccounted for (the originally authorized $57.0 million minus $11.2 million).[447] PG&E replies that the Los Medanos Compressor project is not deferred work and that the funds previously authorized were properly reprioritized.

In reaching our decision, the Commission first finds that the Los Medanos 2023 compressor replacement project meets all three criteria of the Deferred Work Settlement (DWS).[448] The work was requested and authorized in D.16-06-056; PG&E clearly did not perform the work; and PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.

PG&E argues that the DWS does not apply because in the 2019 rate proceeding no party raised the issue of a ratemaking adjustment for PG&E's decision not to replace the Los Medanos compressor, and the Commission did not on its own address the issue as deferred work. The Commission disagrees. The DWS does not specify timelines for the criteria, and the Commission does not find that the timing of this issue being before the Commission now

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[447] PG&E Opening Brief at 201, *citing to* TURN Ex-07 at 40.

[448] Adopted in D.17-05-013, Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2017-2019 (May 11, 2017) and extended in D.20-12-005, Decision Addressing the Test Year 2020 General Rate Case of Pacific Gas and Electric Company (December 3, 2020).

invalidates the DWS. That is, there is no implied waiver for not contesting deferred work in the 2020 proceeding.

Second, in applying the DWS, the DWS does not specify in what manner PG&E must demonstrate the reasonableness of alternative work. After the 2015 rate case, PG&E testified, and the evidence shows, that funding from the Los Medanos project was used to cover $36.5 million of spending over adopted funding on the Physical Security and Upgrade Station Controls programs, and an additional $11.2 million was used to cover the cost overruns due to incremental scope for the Burney Compressor replacement. Moreover, the Los Medanos compressor replacement project was reasonably deferred due to changes in the status of Los Medanos decided by the Commission in D.19-09-025.

Based on these circumstances and prior Commission decisions, the Commission is persuaded by PG&E's explanation regarding its use of the funds originally intended for the Los Medanos replacement project but reprioritized to other necessary work. Accordingly, the Commission adopts PG&E's capital forecast for the Los Medanos compressor replacement project (MAT 76X) of $50.980 million for the Los Medanos K-1 compressor replacement project for the 2023 GRC period, including the following for each year: $9.970 million, $10.219 million, $15.373 million, and $15.418 million in 2023, 2024, 2025, and 2026, respectively.[449]

3.6. Gas Storage

PG&E's Gas Storage includes several asset types: (1) wells and reservoirs for underground gas storage facilities; (2) surface facilities; and (3) gas pipelines

[449] PG&E Ex-03-ES at WP 6-38, line 3.

at the underground storage facilities.[450] PG&E states that it currently operates three storage facilities: McDonald Island, Los Medanos, and Pleasant Creek. In total, PG&E describes its facilities as including 109 injection and withdrawal wells equipped with over 200 miles of casing and tubing that extend approximately one mile into the earth to the storage reservoirs.[451] Additionally, PG&E states that Gas Storage includes approximately 14 miles of transmission pipe and ancillary equipment (of which four miles are designated in high consequence areas); 271 surface and downhole safety valves; and 178 well measurement meters, wellhead separators, and flow controls. PG&E also maintains a 25% interest in the Gill Ranch Storage Facility.[452]

3.6.1. Natural Gas Storage Strategy

This Section provides information regarding how gas supply, demand, storage, and withdrawal are interrelated and analyzed or calculated.[453] In the 1960s and 1970s, when the demand for natural gas was growing and supply from in-state fields was declining, PG&E commissioned three storage facilities at McDonald Island, Los Medanos, and Pleasant Creek. PG&E's states that its storage fields were funded by its bundled customers and, at that time, were the only storage facilities connected to its transmission system. Initially, PG&E explains that the sole purpose for its storage fields was to provide reliability services. Eventually, as price competition was introduced, PG&E states that storage fields were also used to provide commodity price management services

[450] PG&E Opening Brief at 207.

[451] PG&E Opening Brief at 207-208.

[452] PG&E Opening Brief at 207-208.

[453] *See also*, D.19-09-025, Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service (September 12, 2019) for background and history of the components of PG&E's gas storage system.

to noncore customers, which allows lower-priced gas to be stored and used when gas prices are higher.[454]

By the end of the 20th century, PG&E's storage capacity exceeded its reliability needs. In addition, Independent Storage Providers (ISP) were permitted to connect to, and operate on, PG&E's transmission system. The ISPs newer storage fields had a lower cost structure and were constructed with more modern technology.[455]

In 2018, the California Department of Conservation's Division of Oil, Gas and Geothermal Resources (DOGGR) implemented new rules for storage service providers.[456] Compliance with the new rules required PG&E to retrofit its wells and perform additional inspections, both of which have increased costs and reduced the overall withdrawal capacity of PG&E's storage facilities. Given these changes, PG&E weighed the costs and benefits of maintaining the price commodity services for its ratepayers. PG&E concluded that it would cede the business of firm storage-based price management services to the independent storage providers and revise its existing gas storage services to focus on reliability.[457]

PG&E proposed to implement this direction in the last GRC by leaving the commercial storage market and reducing its storage holdings to only the amount

[454] D.19-09-025, Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service (September 12, 2019) at 20.

[455] D.19-09-025, Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service (September 12, 2019) at 20.

[456] On January 1, 2020, the name of DOGGR changed to the California Geologic Energy Management Division (CalGEM).

[457] D.19-09-025, Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service (September 12, 2019) at 21.

necessary to provide reliability services (e.g., managing unplanned outages and inventory fluctuations). To that end, PG&E sought to size its storage assets using a reliability supply standard and a supply strategy outlined in a Memorandum of Understanding, executed between PG&E, several independent storage providers, and TURN.[458]

The above reforms have been collectively referred to as PG&E's Natural Gas Storage Strategy (NGSS).[459] The 2019 Natural Gas Storage Strategy included switching to a reliability-focused storage service strategy by (1) implementing a new reliability supply standard, (2) modifying its storage services, and (3) restructuring its asset holdings. In this way, PG&E states it intends to save money over the next 20 years by not offering a price commodity service.[460]

3.6.2. Peak Day Supply Standard

A key component of the 2019 Natural Gas Storage Strategy is an analysis of the demand and available supply on a peak day to determine the necessary amount of gas storage capacity. In this proceeding, PG&E provided a modified and updated supply standard,[461] reflecting current information and forecasts, as well as events which have occurred since the 2019 GT&S proceeding.[462] PG&E's calculations are presented in Table 3-B, below.[463]

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[458] TURN Opening Brief at 266.

[459] TURN Opening Brief at 266.

[460] D.19-09-025 at 21-23.

[461] TURN Opening Brief at 267. In D.19-09-025 (2019 GT&S decision), peak day analysis was referred to by the Commission as the Reliability Supply Standard. It is referred to in this case as the Peak Day Supply Standard analysis. *See also*, PG&E Opening Brief at 211.

[462] PG&E Ex-03 at 7-43 and 7-46.

[463] PG&E Ex-16 at 7B-13 (Table 7B-1).

Table 3-B
Updated Peak Day Supply Standard Analysis (MMcfd)

		2019	Winter	Winter	Winter
Demand		**NGSS Design**	**2021-2022**	**2022-2023**	**2023-2024**
1. Core		2,493	2445	2572	2575
2. Industrial Demand		522	578	458	460
3. Electric Generation		928	457	897	908
4. Off-System and Shrinkage		123	123	123	123
5. Total Demand	Sum Line 1-4	4,066	3,603	4,050	4,066
6. Total Combined Northern and Southern Supply		3,760	3,723	3,723	3,723
7. Withdrawal needed to meet demand only	Line 5 minus 6	306	-120	327	343
8. Inventory Management and Reserve Capacity		550	550	550	550
9. Total withdrawal needed from PG&E Storage	Line 7 plus 8	856	430	877	893
10. Forecast Withdrawal Capacities at McDonald Island and PG&E Gill Ranch before any capacity investments			808	750	662
11. Capacity Shortfall	Line 10 minus 9		378	-127	-231
Capacity Investments					
12. Retaining Los Medanos			191	180	168
13. Cross Compression				94	93
14. Additional Wells at McDonald Island					
15. Restore PG&E Gill Ranch to 100 MMcfd			22	30	38
16. Total Capacity Additions	Sum Lines 12-15		213	304	299
17. Forecast PG&E Storage capacities after investments	Sum line 10 plus 16		1,021	1,054	961
18. Surplus or shortfall after identified investments	Line 17 minus 9		591	177	68

In Table 3-B, the column entitled "2019 NGSS Design" represents the forecasts that were included in the 2019 NGSS. The columns to the right of the NGSS Design column reflect gas demand if a peak day occurred during a forecast winter (e.g., 2021-2022, 2022-2023, 2023-2024). The rows reflect the demand for gas by PG&E customers, the supply of gas, and the capacity of PG&E facilities to store and withdraw gas to meet the demand. This data illustrates the elements of the NGSS that determine whether PG&E's facilities have sufficient storage and withdrawal capacity to meet demand.

The Peak Day Supply Standard is critical for advance planning to ensure that PG&E has sufficient gas transmission and storage resources on peak day events.[464] In this GRC, the updated Peak Day Supply Standard in Table 3-B helps to determine the amount storage capacity that is included in PG&E's forecasts. PG&E's evidence in this GRC shows the potential for gas storage capacity shortfalls through the 2026-2027 winter. These shortfalls could require shutoffs.[465] Consequently, a decision on a peak day forecast must be made in order to determine the amount of storage withdrawal capacity that PG&E needs during this GRC cycle. The forecasts for core and electric generation demand and the capacity investments proposed to meet that demand are disputed by parties and discussed below.

3.6.3. Core Peak Demand Forecast

The Core Demand is the forecast demand for core customers anticipated during the coldest day-in-10-years (also referred to as "1-in-10 peak day demand" or "peak day gas demand"). PG&E estimates that peak day gas

[464] PG&E Opening Brief at 211.

[465] PG&E Opening Brief at 211-212.

demand by core customers at 2,580 million cubic feet per day (MMcfd) in the winter of 2022-23 and increase to 2,622 MMcfd by the winter of 2026-2027.[466] PG&E's estimate includes the following factors: (1) an updated core customer peak day forecast model created by Marquette Energy Analytics , a firm with recognized expertise in gas demand modeling under contract to PG&E;[467] (2) data in the *2020 California Gas Report*;[468] (3) the retirement of Diablo Canyon Power Plant in 2024 and 2025;[469] and (4) and the connection of thousands of new customers since 2013.[470]

TURN, Wild Goose, LLC (Wild Goose), and Lodi Gas Storage, LLC (Lodi) recommend the Commission adopt a core peak day gas demand forecast of 2,384 MMcfd per year for the rate case period[471] based on the system recorded core peak demand in December 2013.[472] These parties assert that 2,384 MMcfd represents a conservative but reasonable forecast because core peak day gas demand has been in continual decline since that peak in 2013.[473] Furthermore, these parties contend the following: (1) since average daily demand is forecasted to decrease, peak day demand should decrease as well; (2) customers are making energy efficiency improvements and a serious effort to electrify buildings has begun; (3) PG&E's demand forecasts, including core demand, are only based on

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[466] PG&E Ex-16, Table 7B-1 and Table 7B-13.

[467] PG&E Opening Brief at 215-216; TURN Opening Brief at 272.

[468] TURN Opening Brief at 269.

[469] PG&E Ex-03 at 7-47.

[470] PG&E Reply Brief at 208. Wild Goose and Lodi are two ISPs and owned by Rockpoint Storage, LLC.

[471] TURN Opening Brief at 281.

[472] TURN Opening Brief at 273.

[473] TURN Opening Brief at 273.

two years of data, which is not sufficient for a forecast through 2027; (4) the peak day core demand that occurred in December 2013 (2,384 MMcfd) was lower than the core demand reflected in PG&E's updated Peak Day Supply Standard analysis; and (5) the core peak demand forecast from the 2019 GT&S rate case should continue to be used.[474]

The Commission recognizes that considerable uncertainty exists relative to trends in core customer gas use and the demand forecast. The average core demand appears to be declining based on the factors identified by TURN and others. PG&E correctly states, however, that it has connected several thousand new customers since the peak usage in 2013. Moreover, there are significant uncertainties around future demand as a result of climate change and the Commission recognizes the need to responsibly plan for extreme weather conditions. PG&E addressed the uncertainty by using an updated model with the most recent data that accounts for a range of uncertainties. As a result, the Commission is persuaded by PG&E's evidence and, accordingly, the Commission's determination of a reasonable cost forecast for this rate case period (2024-2026) is based on PG&E's core peak demand forecast based on the 2022 *California Gas Report* shown in Table 3-B, above.

3.6.4. Electric Generation Demand Forecast

The second largest component of peak day demand, shown in Table 3-B, is natural gas used by electric generation customers.[475] This is the gas needed for electric generators to support electric reliability on a peak winter day.[476] PG&E

[474] PG&E Opening Brief at 215 to 218; PG&E Reply Brief at 209; TURN Opening Brief at 269-273.

[475] PG&E Ex-16 at 7B-13 (Table 7B-1).

[476] PG&E Ex-03 at 7-49.

presents its forecast for this peak demand event in Table 3-B, above (line 3).[477] PG&E's forecast, shown in PG&E Exhibit-03,[478] is 740 MMcfd for the winter of 2022-23, which declines slightly and then increases to 892 MMcfd by the winter of 2026-2027. The increase starting in the winter of 2024-25 reflects the anticipated retirement of the Diablo Canyon nuclear units.[479]

TURN, Wild Goose, and Lodi disagree with PG&E's electric generation gas forecast for the following reasons: (1) it represents something more like total expected electric generation gas demand rather than the minimum electric generation demand to support electric reliability on a peak winter day; (2) it did not take into account the many new non-gas resources with an accelerated buildout approved in the Commission's Preferred System Plan adopted in D.22-02-004; (3) the core and electric generation demands will not peak on the same day; (4) PG&E should have used a "power flow analysis;" and (5) PG&E's forecast does not include or reflect data from the *2022 California Gas Report (CGR)*.

Based on these considerations, TURN recommends an electric generation gas demand forecast based on an average peak-to-average demand ratio of 1.40 applied to the average monthly peak electric generation (EG) gas demands from the 2020 CGR. This results in a TURN forecast of adjusted electric generation gas peak day demand of 606 MMcfd for winter 2022-23, 599 MMcfd for 2023-24, 601 MMcfd for 2024-25, and 615 MMcfd for 2025-2026.[480]

After careful consideration, the Commission is persuaded by PG&E and will rely on its electric generation gas forecast for determining a cost forecast. As

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477 PG&E Ex-03 at 7-48 (Table 7-15, line 3).

478 PG&E Ex-03 at 7-48 (Table 7-15).

479 TURN Opening Brief at 273-274.

480 TURN Opening Brief at 278.

explained below, however, the Commission increases the usage forecast for the following reasons, taking into consideration the *2022 California Gas Report*.

First, PG&E acknowledges that its forecast does not use the Preferred System Study (wherein the Preferred System Study reflects increased renewable generation that is not natural gas-fired). We adopt an updated peak day demand forecast from the *2022 California Gas Report* (which incorporates the Preferred System Plan from D.22-02-004). The effect of incorporating the Preferred System Study is to produce higher electric generation demand from 2022-2027 than PG&E's forecast.[481]

Second, the parties' forecasts assume early retirement of Diablo Canyon and do not take into account that Diablo Canyon is likely to remain in operation through 2026.[482] The Diablo Canyon power plant is likely to continue in operation due to the extension of the operation of Diablo Canyon for up to five years by Senate Bill 846 and the Nuclear Regulatory Commission's March 2023 letter allowing PG&E to update its previous license renewal application. PG&E's forecast reasonably considers other factors, however, which helps balance the uncertainty of Diablo Canyon's operation. These facts include the increase in electric demand to fuel electric cars, general economic growth, and the growth of

[481] PG&E Opening Brief at 218-219.

[482] Senate Bill 846 authorizes the extension of operating the Diablo Canyon Nuclear power plant beyond the current expiration dates (of 2024 for Unit 1 and 2025 for Unit 2), to up to five additional years (no later than 2029 and 2030, respectively), under specified conditions. SB 846 Floor Analyses, Chapter 239, September 1, 2022; Further, on June 30, 2023, Official Notice was taken of the March 2, 2023 Nuclear Regulatory Commission's letter allowing PG&E to update its previous license renewal application and submit a sufficient license renewal application for DCPP Units 1 and 2, by December 31, 2023, and, if it does so, receive timely renewal protection under 10 CFR 2.109(b). https://www.nrc.gov/docs/ML2302/ML23026A109.pdf.

all-electric homes, that will likely increase the peak day need for gas-fired generation.[483]

Third, the Commission must consider the impact of core customer and electric generation gas demand peaking on the same day. That is, both PG&E and TURN estimate that 23% of the time there is a correlation between core customer peak demand and electric generation peak demand. This correlation cannot be ignored and is reasonably considered in PG&E's forecast.

Fourth, PG&E acknowledges that its forecast was not developed using a power flow analysis. We use *the 2022 California Gas Report*, however, which did use a power flow analysis. The result is a higher electric generation peak day demand forecast than that of PG&E.[484]

Fifth, the Commission considers the relevance of both the *2020 and 2022 California Gas Reports* to the parties' forecasts. The electric generation numbers in the *2020 California Gas Report* are for average daily winter demand, not peak day demand. The demand forecast from the *2022 California Gas* Report is peak day and is the most recent data. The result is a higher forecast for electric generation than that of PG&E.[485]

Sixth, there are important new conditions due to CalGEM requirements for well re-inspection intervals. The result is a loss of storage withdrawal capacity due to increased well inspections required by CalGEM regulations.[486] PG&E's electric generation forecast is more conservative than that of the other parties by considering the new well re-inspection intervals.

[483] PG&E Opening Brief at 219.

[484] PG&E Opening Brief at 221.

[485] PG&E Opening Brief at 221-222.

[486] PG&E Opening Brief at 224.

Based on all these factors, Commission relies on the *2022 California Gas Report* for cost forecasting purposes in this this proceeding and the electric generation peak day demand as shown in the Table 3-B, above

3.6.5. Other Gas Supply Demand Components and Total Demand

Parties do not dispute industrial demand, off-system use, and shrinkage. The Commission relies on those forecasts as shown in Table 3-B, above, for purpose of determining cost forecast in this proceeding.

To those forecasts we add the results for core and industrial demand to produce the adopted total gas demand, as shown in Table 3.5.2. This demand forecast is (based on PG&E's Revised Table 7-15[487] and the 2020 and *2022 California Gas Reports*[488]) only approved for the winter of 2023 through 2024. This is because the parties have not provided forecasts for 2024 that include the continued operation of both Diablo Canyon units.

As a result, the Commission finds that the gas supply standard should be improved to resolve uncertainties presented by parties' disputes over the definition of the electric generation standard and data. Consequently, the Commission directs PG&E to include an update to its revised Peak Day Supply Standard in a new application discussed in Section 3.5.3 below. The purpose of requiring PG&E to resubmit its supply standard is to improve its methodology and include changed circumstances, such as changes in the operation of the Diablo Canyon Power Plants after 2025,[489] the Preferred System Study, the latest

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[487] PG&E-03 at 7-48 (Table 7-15).

[488] PG&E Ex-16 at 7B-13 (Table 7B-1).

[489] Senate Bill 846 authorizes the extension of operating the Diablo Canyon Nuclear power plant beyond the current expiration dates (of 2024 for Unit 1 and 2025 for Unit 2), to up to five additional years (no later than 2029 and 2030, respectively), under specified conditions. SB 846

Footnote continued on next page.

California Gas Report, and the impact of new well inspection regulations on gas storage capacity, among others.[490]

3.6.6. Curtailment Process

The parties contend that PG&E's curtailment process may substitute for reserve capacity.[491] To assess this, we first briefly describe PG&E's storage services.

PG&E provides two storage services in addition to core storage: inventory management and reserve capacity. Inventory management includes gas storage capacity needed to operate the system and to meet large intraday demand swings created by core and electric generation gas customers. Reserve capacity is intended to provide the system with an intraday supply of gas in case of significant unplanned equipment outages or other supply problems (e.g., forecasting errors, reduction of supply at an interconnect, demand forecast uncertainty, a pipeline outage). When an outage or other event occurs that is beyond the capability of the reserve capacity to serve, PG&E has a process for curtailing service to certain non-core customers.[492]

Floor Analyses, Chapter 239, September 1, 2022; Further, on June 30, 2023, Official Notice was taken of the March 2, 2023 Nuclear Regulatory Commission's letter allowing PG&E to update its previous license renewal application and submit a sufficient license renewal application for DCPP Units 1 and 2, by December 31, 2023, and, if it does so, receive timely renewal protection under 10 CFR 2.109(b). https://www.nrc.gov/docs/ML2302/ML23026A109.pdf.

[489] TURN Opening Brief at 284.

[490] Note: no aspect of this decision makes any assumptions regarding how costs should be allocated among the core and noncore customers in the GT&S Cost Allocation and Rate Design proceeding. TURN Opening Brief at 286.

[491] PG&E Opening Brief at 224-230.

[492] D.19-09-025, Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service at 36; PG&E Ex-03 at 7-54.

In D.19-09-025, the Commission directed PG&E to propose improvements in its curtailment process for consideration in this rate case. The Commission also ordered that PG&E's proposal evaluate whether PG&E can implement hourly curtailments.[493] PG&E's showing here, however, does not address how its curtailment process can be improved. Moreover, its evaluation of hourly curtailments is essentially limited to arguing they are not feasible.[494]

The result is that the Commission lacks sufficient evidence in this proceeding to consider modifying PG&E's curtailment process as a substitute for reserve capacity. As the parties have correctly noted,[495] the Commission has approved curtailment orders for other utilities.[496]

Accordingly, the Commission once again directs PG&E to address this issue and, within 180 days of the effective date of this decision, file an application for authority to revise its curtailment procedures similar to the curtailment procedures of other large energy utilities. PG&E's application should consider input from stakeholders consistent with past practice. The Commission expects PG&E and parties to provide sufficient evidence to allow us to consider improvements in PG&E's curtailment protocol

3.6.7. Los Medanos Storage Facility

The Los Medanos gas storage facility is located in Contra Costa County and was placed into service in 1980. It is the second largest of PG&E's storage

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[493] D.19-09-025, Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service at 34, 35, 40, and 322 (OP 10).

[494] PG&E Opening Brief at 224-232.

[495] TURN Opening Brief at 282-283.

[496] D.16-07-008, July 14, 2016, A15-06-020, Application of Southern California Gas Company and San Diego Gas & Electric Company for Authority to Revise their Curtailment Procedure https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M165/K051/165051361.pdf.

fields, with a design working capacity of approximately 17 billion cubic feet (BCF). This facility has 21 injection/withdrawal wells and one observation well for monitoring reservoir integrity.[497]

The Commission approved a process in the 2019 GT&S case for decommissioning the Los Medanos storage facility. The process involved PG&E addressing storage capacity uncertainties after the shutdown. In particular, PG&E was required to address: (1) whether PG&E would have the requisite storage capacity to operate without the Los Medanos storage field, and (2) other supply constraints that could be exacerbated by closing Los Medanos. Relatedly, the Commission also noted possible uncertainties in the estimates of the withdrawal and injection capacity at the McDonald Island facility after PG&E began complying with DOGGR (now CalGEM) regulations.[498]

PG&E now proposes retaining the Los Medanos gas storage facility. PG&E makes that recommendation based on the following: (1) a shortfall in gas withdrawal capacity identified by its gas supply forecasts and analysis; (2) the relative cost-effectiveness of operating Los Medanos compared to other alternatives; and (3) the claim that ISP capacity is not a reasonable substitute for Los Medanos.[499]

TURN recommends not retaining the Los Medanos storage field. TURN argues that its revised gas supply standard analysis shows no shortfall in gas storage. In support, TURN claims that its revised analysis exhibits a margin for

[497] PG&E Ex-03 at 7-7; D.19-09-025, Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service at 58.

[498] D.19-09-025, Decision Authorizing Pacific Gas and Electric Company's 2019-2022 Revenue Requirement for Gas Transmission and Storage Service at 71-72.

[499] PG&E Opening Brief at 233-243.

error of at least 134 MMcfd in each year of the forecast period.[500] Further, TURN describes three other factors that may increase the supply of gas compared to its demand. First, there is an increased possibility that the Diablo Canyon power plant will continue to operate for another five years, significantly reducing the need for gas-fired electric generation on peak days, as well as throughout the year.[501] Second, TURN contends that an additional 250 MMcfd of withdrawal capacity could be eliminated by PG&E adopting a gas curtailment system similar to that employed by Southern California Gas Company (SoCalGas). Third, TURN recommends investigating whether the installation of additional pipes to connect a Rockpoint gas storage field to the PG&E transmission system would eliminate constraints and supplement withdrawal capacity.[502]

The Commission finds substantial uncertainties remain, and the evidence fails to establish that PG&E has the requisite storage capacity to operate without Los Medanos. Therefore, the Commission finds that PG&E should maintain its operation of the Los Medanos Storage Facility.

Further, the evidence does not sufficiently show the impact new inspection regulations will have on gas storage capacity. Accordingly, the Commission requires PG&E to provide an update regarding this impact in its application to revise its supply standard discussed above.

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[500] TURN Opening Brief at 281-282.

[501] Senate Bill 846, Floor Analysis, Ch. 239, September 1, 2022; *see also* TURN Opening Brief at 282 regarding the Nuclear Regulatory Commission's March 2, 2023 decision to allow PG&E to update its previous license renewal application. Further, on June 30, 2023, Official Notice was taken of the March 2, 2023 Nuclear Regulatory Commission's letter allowing PG&E to update its previous license renewal application and submit a sufficient license renewal application for DCPP Units 1 and 2, by December 31, 2023, and, if it does so, receive timely renewal protection under 10 CFR 2.109(b). https://www.nrc.gov/docs/ML2302/ML23026A109.pdf.

[502] TURN Opening Brief at 284.

3.6.8. Gas Well Drilling (MAT 3L1)

PG&E proposes a forecast to support drilling 12 new wells at the McDonald Island facility during the rate case period. Three of these 12 new wells will address the capacity shortfall forecasted in PG&E's Peak Day Supply Standard analysis discussed above. The remaining nine wells will provide needed withdrawal and deliverability capacity given increased re-inspection frequency, reworks/retrofits, and CalGEM regulations.[503] PG&E forecasts the well drilling capital costs to be $18.886 million in 2023, $45.884 in 2024, and $32.973 in 2025.[504] TURN opposes PG&E's request, contending that the analysis of gas supply does not demonstrate the need for new wells.[505]

As discussed above, the ability of PG&E's well storage to meet the forecasted demand is uncertain for a number of reasons. First, the forecast for total demand is unclear, particularly given the need for gas during uncertain future extreme weather events. Second, the impact on well storage capacity due to mandated increases in well inspections has yet to be fully determined. Third, although the continued operation of Diablo Canyon in 2024-2026 appears likely, the margin of error for PG&E's storage capacity to meet demand is low, even with the retention of the Los Medanos. For example, even with retaining Los Medanos but without new wells, Revised Table 3.5.2 above shows a surplus in gas storage capacity next winter of only 68 MMcfd.

Based on these and other uncertainties, the evidence justify the forecast as it demonstrates a need for additional well drilling. Accordingly, the Commission

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[503] PG&E Ex-03 Vol. 2, WP at 47; PG&E Opening Brief at 243.

[504] PG&E Opening Brief at 244.

[505] TURN Opening Brief at 300.

adopts PG&E's request for capital costs for additional well drilling tracked in MAT 3L1 of $18.886 million in 2023, $45.884 in 2024, and $32.973 in 2025.

3.6.9. Well Reworks and Retrofits (Capital - MAT 3L3)

The Well Reworks and Retrofits activity (or "reworks") addressed in this Section is a capital program. (A subsequent Section will address the expense portion). This capital program involves converting wells from their existing condition to dual barrier construction consistent with CalGEM requirements and regulations. Reworks can also be required by other activities, such as pressure testing. The MAT 3L3 funding category includes the capital work associated with retrofit, repair, or assessment of the storage well to: (1) mitigate a single point of failure (i.e., installation of dual barrier); (2) assess the condition of a well; and/or (3) perform corrective work.[506]

PG&E forecasts 56 reworks over the rate case period. PG&E's 2023 capital expenditure forecast is $85.199 million. However, as reworks are completed, the capital expenditures decline to $18.553 million in 2026.[507] The parties dispute the number and cost of reworks. We address each in turn.

3.6.10. Number of Gas Well Reworks

PG&E forecasts 40 of the 56 gas well reworks will be associated with wells that are scheduled for conversion. The remaining 16 reworks are associated with emergent or unplanned work. PG&E states that emergent work is identified during the course of routine monitoring, surveillance, and/or testing as requiring a rig to be brought in for further investigation and/or mitigation.

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[506] PG&E Opening Brief at 246.

[507] PG&E Reply Brief at 229-230.

TURN recommends two emergent reworks per year for a total of eight through 2026, thereby reducing the 2023 capital expenditure forecast by $22.148 million to $63.051 million.[508] TURN's lower forecast is based on the number of reworks in PG&E's initial filing.

The Commission is persuaded by TURN. In its revised testimony, PG&E increased the number of emergent reworks in anticipation of an increase in the number of well pressure tests required by CalGEM and the need for a rig. The number, however, is essentially unknown.[509] Given this uncertainty, the Commission approves PG&E's initial estimate of reworking two emergent wells per year. If a higher number of well reworks is needed, PG&E may account for the difference by an adjustment in the Gas Storage Balancing Account.[510]

3.6.11. Cost of Gas Well Reworks

PG&E classifies well reworks into three types with differing costs: Types 1, 1a, and 2. Because the work for each type varies, the costs also vary. Typically, PG&E explains, Type 1 reworks are the least expensive and Type 2 the most expensive. PG&E used a cost calculator to estimate the cost for each type of rework and averaged the costs to arrive at an overall unit cost forecast of $3.298 million per well (in 2020 dollars). PG&E contends that its averaging approach captures the range of costs across each type of well and category.[511]

TURN recommends a lower cost of $3.031 million per well (in 2020 dollars). TURN's approach primarily uses a weighted average instead of a

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[508] PG&E Reply Brief at 230.

[509] TURN Opening Brief at 291.

[510] TURN Opening Brief at 292.

[511] PG&E Opening Brief at 249.

simple average.[512] The Commission finds TURN's forecast based on the weighted average to be reasonable and uses it to determine the 2023 Well Reworks and Retrofits activity forecast.

As a result of our use of TURN's evidence on the adopted number and cost of reworks, the Commission adopts a total well rework forecast (MAT 3L3) of $63.051 million for 2023, $56.891 million for 2024, $6.717 million for 2025, and $6.869 million for 2026 (subject to adjustment in the Gas Storage Balancing Account if a higher number of well reworks are needed).

3.6.12. Gas Controls and Monitoring (Capital MAT 3L5)

PG&E states that the Controls and Monitoring program includes installing safety-related equipment to monitor pressure and flow at PG&E's storage fields. Projects in this program include installation or replacement of equipment to: (1) monitor pressure at storage fields; (2) monitor injection flow at McDonald Island; (3) replace older monitoring equipment at McDonald Island. In addition, this program includes necessary control upgrades at the Los Medanos facility. These upgrades mitigate storage well control failures or an inability to monitor well performance that can result in a loss of gas isolation, uncontrolled flow, or lost production from a storage well.

TURN objects to the funding of control upgrades at the Los Medanos facility.[513] Since the Los Medanos facility is being retained as discussed above, the Commission adopts PG&E's forecast for Controls and Monitoring (MAT 3L5) of $1.365 million in 2023, $7.525 million in 2024, and zero funding for years 2025 and 2026.

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[512] TURN Reply Brief at 287 to 290-293.

[513] PG&E Opening Brief at 251-252.

3.6.13. Gas Well Reworks and Retrofits (Expense MAT AH2)

The Well Reworks and Retrofits activity addressed in this Section is an expense item. (A prior Section, herein, addressed the capital potion.) PG&E states that this activity involves the performance of well re-inspections following conversions required by CalGEM's regulations. In addition, it includes work to address emergent integrity issues that require rig mobilization (i.e., response to a failed pressure test). PG&E refers to the work in this program as "re-inspection" work.[514]

PG&E forecasts the cost of each re-inspection at $1.513 million in 2020 dollars.[515] Initially PG&E projected that this activity would not begin until 2026, when 11 re-inspections would be required. Later, PG&E added 10 additional emergent or unplanned re-inspections (two each in 2023 and 2024, and three each in 2025 and 2026) for a total of 14 in 2026.[516] The number of re-inspections can depend upon the frequency of those re-inspections. Regarding the frequency, PG&E's 2021 Revised Implementation Plan proposes a re-inspection frequency that generally occurs between eight and 15 years. In contrast, PG&E states that it bases its forecast here on the assumption that PHMSA guidance and regulations will require such inspections every seven years.[517] On the other hand, PG&E reports that CalGEM's regulations currently call for a two-year re-inspection interval but also allow CalGEM to review an alternate frequency should an operator contend that the corrosion growth rate would be negligible in two years.

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[514] PG&E Opening Brief at 253-254.

[515] TURN Opening Brief at 293.

[516] PG&E Opening Brief at 254.

[517] PG&E Opening Brief at 255.

PG&E states that it has petitioned for a risk-based inspection interval that would be other than every two years, and an answer from CalGEM is pending.[518] As a result, PG&E contends that CalGEM may require direct downhole casing re-inspections more frequently than every seven years. Based on its consideration of all factors, PG&E requests authorization to fund 11 direct casing re-inspection projects planned in 2026 that would require rig mobilization.

TURN recommends reducing the number of re-inspections to three.[519] TURN asserts that emergent re-inspection work should not be required on wells that have recently been reworked. Further, TURN shows that a PHMSA publication states that "there is no prescribed maximum interval for performing downhole integrity inspections" and that "an operator must develop and implement a process that incorporates risk analysis and integrity assessment results to schedule subsequent downhole integrity inspections."[520]

The Commission finds there is some degree of regulatory uncertainty. It is also clear, however, that regulators consider the risk assessment presented by an operator. As a result, the Commission directs PG&E to provide a better risk-assessment to support this request in the next GRC.

For this GRC, the Commission adopts an expense forecast for Well Reworks and Retrofits (MAT AH2) that authorizes six direct downhole casing re-inspections. Using PG&E's escalated unit cost forecast, the Commission adopts a forecast for MAT AH2 of $3.207 million for 2023.

[518] TURN Opening Brief at 295-297.

[519] TURN Opening Brief at 298.

[520] TURN Opening Brief at 294.

3.6.14. Well Integrity Assessments (Expense MAT AH1)

PG&E states that its Integrity Inspections and Surveys Program covers work performing integrity inspections and surveys on storage wells. This includes the following: (1) annual and periodic compliance surveys; (2) thru-tubing barrier inspection surveys; and (3) direct well integrity and production casing/barrier inspections and tests.[521]

PG&E's 2023 expense forecast for this program is $9.177 million. PG&E's expense forecast for 2024-2026 is not based on escalation but rather the amount of work forecast for each year. These forecasts are based on PG&E's estimate that 12 new wells will have to be drilled to meet the Peak Day Supply Standard (with each requiring scheduled testing) and that Los Medanos will be retained (requiring an additional 18 existing wells to be tested).[522] TURN's estimate differs from the company's only with respect to the number of wells that will have to be tested each year in order to comply with CalGEM's regulations.

As described above, the Commission adopts a forecast both allowing the drilling of 12 new wells at McDonald Island and retaining the Los Medanos facility. Consistent with those decisions, the Commission approves PG&E's proposed testing of 12 new wells and 18 existing wells. Accordingly, the Commission adopts of PG&E's Well Integrity Assessment Program (Expense MAT AH1) forecast[523] of $9.177 million in 2023.

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[521] PG&E Opening Brief at 252.

[522] TURN Opening Brief at 299-300.

[523] PG&E Opening Brief at 253.

3.6.15. Gas Storage Balancing Account

The Commission adopted the Gas Storage Balancing Account (GSBA) in the 2019 GT&S Rate Case.[524] The GSBA is a two-way balancing account that tracks the revenues it receives based on approved rates, as well as the actual expenditures it incurs. To the extent expenditures exceed revenues, PG&E is entitled to recover these costs after submitting an application to the Commission. To the extent expenditures are less than revenues, the amount collected over revenues is return to PG&E's customers.[525] It recognizes the significant regulatory uncertainty regarding gas storage regulations and requirements, and the resulting costs. In this rate case, PG&E proposes continuing the GSBA based on ongoing uncertainties regarding gas storage regulations and costs, as well as uncertainties inherent in storage well work. PG&E proposes one modification, described below.[526]

In the 2019 GT&S rate case, the Commission required that "[i]n the next rate case, PG&E shall submit an analysis comparing the total recorded costs with the authorized amount, and the Commission shall determine whether the transactions in the balancing account are reasonable."[527] Doing this determination in rate cases, however, creates a substantial delay in returning over-collected amounts to customers or recovering under-collected costs in rates. The delay occurs because rate cases are now based on a four-year cycle. Moreover, rate cases themselves typically take several years to reach resolution.

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[524] D.19-09-025.

[525] PG&E Opening Brief at 258.

[526] PG&E Opening Brief at 257.

[527] PG&E Opening Brief at 258, citing to D.19-09-025 at 95.

As a result, the return of excess amounts or recovery of under-collected amounts can take years.[528]

To address this problem, PG&E proposes changing how costs recorded in the GSBA are recovered. Specifically, PG&E proposes filing a Tier 2 Advice Letter each year after the GSBA recorded costs are final for that year, typically in April. The advice letter would provide details regarding the actual costs incurred compared to the adopted forecast amount, indicate whether there was an over- or under-collection, and create a vehicle for PG&E to either return the overcollection or to recover the under-collection. If a party protests the Tier 2 Advice Letter, PG&E notes that the Tier 2 advice letter can either be converted into a Tier 3 Advice Letter or PG&E can be required to file an Application.[529]

TURN urges the Commission to reject review of the GSBA via an advice letter. Rather, TURN contends that this approach would not allow interested parties enough time to investigate what may be complex issues of fact.[530]

The Commission finds that PG&E's proposal strikes a fair balance between reviewing recorded costs in a timely manner and providing parties an opportunity to request an alternative approach. Moreover, when the alternative approach is used, it involves formal Commission review and approval of disputed costs. Accordingly, the Commission adopts the modifications to the GSBA proposed by PG&E.

3.7. Gas Operations and Maintenance

PG&E's 2023 forecast in PG&E Ex-03 includes expense forecasts and capital expenditure requests for both Gas Distribution and GT&S assets. PG&E

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[528] PG&E Opening Brief at 258.

[529] PG&E Reply Brief at 314-315.

[530] TURN Reply Brief at 83-86.

presents its forecast subdivided into three programs: (1) O&M expense, (2) corrosion control programs, and (3) leak management programs. PG&E states that these programs support the maintenance of other assets, including distribution mains and services, transmission pipe, measurement and control, compression and processing, compressed natural gas, and storage.[531]

3.7.1. Locate and Mark (Expense MAT DFA)

PG&E states that the Locate and Mark Program activities are required to identify PG&E's distribution and transmission assets for third parties who plan to dig near those assets pursuant to federal regulations, 49 CFR, Part 192. Such assets include gas, electric, and fiber optic facilities.[532] In addition, PG&E states that Government Code Section 4216 requires PG&E to belong to and share the costs of operating the regional "one-call" notification system. The one-call notification system is commonly referred to as Underground Service Alert (USA). Prior to excavating, work crews must call 811 to obtain a USA ticket, which is transmitted electronically to PG&E. PG&E states that then it may locate and mark all subsurface installations identified within the area of proposed excavation, provide records of subsurface installation locations, or advise the excavator that PG&E operates no facilities within their proposed area of excavation.[533]

PG&E's 2023 expense forecast is based on the number of Locate and Mark USA Tickets worked on during 2019 split between Gas Distribution and Gas Transmission, with a 12% per year increase applied. PG&E states that the 12% rate of increase is based on the increase in ticket volume between 2018 and 2019.

[531] PG&E Opening Brief at 260.

[532] PG&E Ex-03 at 8-10 (fn. 5).

[533] PG&E Opening Brief at 262.

PG&E's unit cost forecast is based on a three-year average of recorded costs (2017-2019) and escalated to 2023. For the Gas Distribution cost forecast, PG&E states it considered the following additional factors: (1) ten minutes was added to the three-year average job time of 35 minutes to capture the additional time it takes to respond to tickets (new ticket management system as well as updates to the Locate and Mark Field Guide and Field Procedures), and (2) Fiber Optic costs which were previously recorded to IT. PG&E's expense forecasts for 2023 is $77.575 million for the Gas Distribution Locate and Mark Program based on a number of 904,808 tickets worked.[534] Although PG&E's forecast for this program is assigned to the gas line of business, 33% of the resulting revenue requirement is allocated to electric distribution as it was in PG&E's 2020 GRC.[535]

3.7.1.1. Rate of Locate and Mark Activity

TURN and Cal Advocates recommend reductions in PG&E's forecast based on their opinion that a decrease in the rate of locate and mark activity is appropriate. TURN recommends a reduction of 41,126 tickets worked to a total of 863,682 in 2023 based on the recorded average annual increase in tickets worked from 2016–2019. This data produces a growth rate of 10% instead of 12, which TURN applies beginning in 2020.[536]

Cal Advocates recommends a reduced forecast based on a lower number of worked Locate and Mark Tickets and suggests a total of 688,134 Locate and Mark Tickets is appropriate based on an average of 2016-2020 data and a 5% increase per year from 2021 to 2023. Cal Advocates recommends this outcome and methodology based on the following: (1) between 2019 and 2020, the number

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534 PG&E Opening Brief at 262-263.

535 PG&E Ex-03 at 8-80 to 8-81.

536 PG&E Opening Brief at 262.

of tickets PG&E processed declined by 8%; (2) PG&E processed only a 2.7% increase in tickets in 2021; (3) between 2016 and 2020, the average increase in tickets processed is approximately 5% per year.[537]

PG&E proposes using the 12% increase seen in ticket volume between 2018 and 2019, the most recent full year of tickets worked that was not impacted by work stoppages caused by the COVID-19 pandemic. In support of this methodology, PG&E states the following: (1) the 12% growth rate accounts for additional ticket volume expected in the future related to new regulations which established the California Underground Facilities Safe Excavation Board's (Excavation Board) excavation investigation and enforcement authority; (2) new regulations include implementing the use of Area of Continuous Excavation (ACE) tickets, and investigation and enforcement by the Excavation Board of all excavators, not just in ACE areas; (3) PG&E's forecast reflects the overall growth of tickets it expects when the Excavation Board fully implements its oversight program; (4) the California Dig Safe Board 2020 Results Report states that planned in-person events targeting outreach were hampered by the COVID-19 pandemic; (5) due to COVID-19 the Excavation Board had not fully implemented its enforcement program in 2020, so that growth in tickets in not reflected in 2020 data.[538]

After disputing the conditions impacting recent locate and mark activity, the parties debated what data best forecasts locate and mark activity during through 2026. Cal Advocates opined that the Commission should consider a broader range of historical data due to the variability in PG&E's ticket volume

[537] Cal Advocates Opening Brief at 72-74.

[538] PG&E Reply Brief at 239-240.

and the unknown impact of PG&E's outreach and education efforts.[539] PG&E used a three-year average escalated by the increase between 2018 and 2019, prior to the pandemic because PG&E believes best reflects the aggressive and escalating outreach to excavators being implemented by the Excavation Board. TURN opined that the use of a single year (e.g., last year recorded) of data is only valid if (1) there is no variability, and/or (2) there are changed circumstances that will persist. Furthermore, TURN argues that neither of the above factors is present, and the variability of historical data warrants the use of a multi-year average. In addition, the only changed factor is the new regulations related to ACE tickets, which were implemented in mid-2020,[540] for which growth in tickets has not materialized yet.[541]

Based on the totality of the above facts, the Commission finds TURN's recommendation, which is based on an average of the most recent pre-COVID recorded years (2016-2019), to be the most persuasive, which reflects a 10% growth rate since 2020 and 863,682 expected Locate and Mark Tickets in 2023.

3.7.1.2. Locate and Mark Unit Cost

PG&E recommends a unit cost of $86 per Locate and Mark Ticket[542] based on PG&E's unit cost forecast is based on a three-year average of recorded costs (2017-2019) with escalation.[543]

539 Cal Advocates Reply Brief at 33.

540 TURN Reply Brief at 75.

541 PG&E Reply Brief at 239.

542 PG&E Ex-03 at WP (Table 8-6), WP 8-11, and 8-12.

543 PG&E Opening Brief at 262.

Cal Advocates recommends a $49 unit cost based on the 2020 unit cost, escalated to $54 for the 2023 unit cost.[544] Cal Advocates asserts that the proposed job time increase in 2023 was already captured in 2020 because the new regulatory oversight and requirements were already implemented by July 1, 2020. PG&E responds that Cal Advocates' unit cost is too low because: (1) 2020 did not represent normal operating conditions as it was impacted by work stoppages caused by the COVID-19 pandemic; and (2) it excluded shareholder-funded costs from the unit cost calculation that will become part of base ratepayer expenses in 2023.[545]

The Commission finds PG&E's unit cost of $86 per Locate and Mark Ticket to be persuasive. Accordingly, the Commission adopts TURN's recommended 2023 expense forecast of $74.277 million for the Locate and Mark Program (MAT DFA) based on forecast work of 863,682 Locate and Mark tickets in 2023 at a unit cost of $86 per ticket.

3.7.2. Standby Governance (MAT DFB)

In the standby process, a PG&E field employee monitors excavation activity on both Gas Distribution and Gas Transmission (GT) assets in a watch and protect capacity to prevent damage to PG&E's critical facilities. Examples of activities where PG&E performs a standby include excavations that are within five feet of the nearest edge of a critical facility and boring activities that cross a critical facility within ten feet of its nearest edge. PG&E's 2023 expense forecast

544 PG&E Reply Brief at 241.

545 PG&E Opening Brief at 266-267.

for Gas Distribution Standby Governance is $0.451 million[546] and for Gas Transmission Standby Governance is $7.237 million.[547]

3.7.2.1. Gas Distribution Standby Governance

TURN recommends a lower 2023 expense forecast for Gas Distribution Standby Governance of $0.442 million based on a growth rate for standby tickets of 10% (as opposed to 12% proposed by PG&E) beginning in 2020 and annually thereafter.[548]

PG&E's states that its forecasted increase in Locate and Mark tickets is also expected to drive up the need to perform standbys due to the correlation between USA tickets worked in the Locate and Mark Program (MAT DFA) and the need for standby activities (MAT DFB). PG&E proposes that the 12% rate for DFA (Section 3.7.1.1, herein) should also apply to DFB work. As PG&E forecasts an increase in Locate and Mark tickets, it is expected that the need to perform standbys will also increase.

Since the Commission adopted a growth rate for Locate and Mark tickets in Section 3.7.1.1, herein, of 10% beginning in 2020, the Commission finds persuasive TURN's recommended 2023 expense forecast of $0.442 million for Gas Distribution standby governance for 2023, which is $9,000 less than PG&E's 2023 expense forecast of $0.451 million.

3.7.2.2. Gas Transmission Standby Governance

PG&E states that is bases its forecast for Gas Transmission Standby Governance on its expectation that the need for activities will continue to increase in direct correlation with PG&E's projected increase in Locate and Mark

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546 PG&E Opening Brief at 267-268.

547 PG&E Ex-03-ES at iii.

548 TURN Opening Brief at 303.

tickets of 12%. However, PG&E acknowledges that beginning in 2019, the standby governance team implemented new processes and procedures that reduced standbys and made the group more efficient and effective.[549]

In contrast, TURN recommends a 2023 expense forecast for Gas Transmission Standby Governance of $5.349 million, which is $1.889 million lower than PG&E's forecast of $7.237 million.[550] TURN contends that the continuing work of the Standby Governance Team justifies using the 2019 recorded units (5,221) as the basis for the 2023 forecast without escalation.[551]

Since the Commission adopted a growth rate for Locate and Mark tickets in Sections 3.7.1.1 and 3.7.1.2 of 10% beginning in 2020, the Commission finds persuasive TURN's forecast for Gas Transmission standby governance for 2023. Accordingly, the Commission adopts a 2023 expense forecast gas transmission standby governance of $5.349 million.

3.7.3. Meter Protection Program

The Meter Protection Program protects meters and risers that are vulnerable to vehicular damage and installs service valves where existing service valves are inaccessible. Federal regulations require utilities to protect meters, but do not provide a timeframe for remediation.[552] Meter protection is primarily accomplished through the installation of steel posts (bollards). If a meter is inadequately protected, PG&E field personnel document it as an abnormal operating condition (AOC) that may need remediation.[553] When PG&E installs

[549] PG&E Opening Brief at 270.

[550] TURN Opening Brief at 304.

[551] TURN Opening Brief at 307.

[552] 49 CFR § 192.35; TURN Opening Brief at 308.

[553] PG&E Opening Brief at 270.

bollards, the work is charged to expense MAT EXB. However, in cases where meter protection posts cannot be installed to protect the meter, PG&E relocates the meter and replaces the service. Such work is generally more expensive and is charged to capital account MAT 27A for Meter Relocation.[554]

PG&E classifies the work it performs at meter locations by the following types:

(1) Can't Get In (CGI) locations: CGI locations are sites where no access is available to perform meter protection work, which are more complex and costly to remediate. Based on work performed by PG&E's contractor in 2020, PG&E estimates that 8% or 3,410 meter locations are CGI locations.

(2) New Finds: PG&E expects to find 19,380 new abnormal operating condition (AOC) locations annually through leak surveys, atmospheric corrosion inspections, and other field activities. PG&E documented a find rate from leak surveys and atmospheric corrosion inspections in 2020. PG&E applied the number of 2020 new finds to the 2021 inspection plan to estimate the forecast of 19,380 new abnormal operating conditions to remediate in 2023 over two years.

(3) Existing Locations: PG&E has documented a backlog of 81,133 existing AOC locations it proposes to remediate by 2026 based on relative risk ranking. PG&E forecasts that it will remediate a quarter of the existing backlog each year through 2026 or 20,283 locations in 2023.

(4) Customer Call-ins: PG&E estimates that it will visit 120 meter locations in 2023 based on customer requests over the last five years.

[554] TURN Opening Brief at 308.

3.7.3.1. Meter Protection Program (Expense MAT EXB)

For The Meter Protection Program (MAT EXB), PG&E's 2023 expense forecast is $35.442 million based on 43,193 meter protection locations at a unit cost of $821 per location.[555] The 2023 forecast for MAT EXB consists of four separate projections:

(1) 3,410 CGI locations based on an 8% CGI rate seen from work performed by PG&E's contractor in 2020;

(2) 19,380 "New Finds" based on expected new AOC locations identified through routine Leak Survey and Atmospheric Corrosion (AC) inspection plans along with field services activities;

(3) 20,283 Existing AOC Locations based on total pending meter protection locations (81,133) divided by the four-year 2023 rate case period; and

(4) 120 Customer Call-ins.[556]

PG&E's total 2023 expense forecast is more than triple PG&E's 2020 recorded expense of $11.471 million. PG&E proposes an increase in the rate of remediating meter locations primarily to reduce the backlog of existing locations needing remediation.[557] PG&E explains that is 2023 unit cost forecast for the Meter Protection Program reflects a blend of Non-CGI and CGI remediation costs.[558]

For MAT EXB, Cal Advocates recommends a lower amount for the following reasons: (1) zero meter remediations for the CGI category because

[555] PG&E Opening Brief at 272.

[556] PG&E Reply Brief at 245.

[557] PG&E Reply Brief at 243-247.

[558] PG&E Opening Brief at 270-271.

CGIs are no longer a stand-alone source to identify meters for remediation;[559] (2) a forecast of 9,204 New Find meters for PG&E to remediate in 2023;[560] (3) that the Commission specifically authorize PG&E to remediate 6,217 existing AOC meters per year starting in 2023;[561] (4) zero-meter remediations from the Customer Call-Ins category because PG&E's estimates are inadequately supported.[562] Cal Advocates' suggests reducing PG&E's 2023 expense forecast for costs tracked in MAT EXB by approximately $22.783 million.

TURN recommends that new AOC finds be mitigated within PG&E's existing two-year policy, to avoid expanding the backlog of remediation needs. In the past, PG&E has allowed backlogs of unprotected sites to build up. TURN recommends that PG&E remediate existing AOC locations over a longer period of twenty years, rather than ten years based on vehicular damage to vulnerable meters having an extremely low risk of loss of containment, as reflected in a very low-risk spend efficiency score and benefit/cost ratio. TURN adds that the longer rate would minimize near-term rate impacts. This policy allows remediation of the existing AOC locations in two-thirds of the time it took PG&E to remediate the 1990 backlog under the Meter Protection Program.[563] TURN recommends reducing the number of annual existing meter remediations over twenty years from 20,283 units to 4,057 units, for a reduction of $12.510 million for costs tracked in MAT EXB, but it does not address the other types of meter remediations noted above.

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[559] Cal Advocates Opening Brief at 81-82.

[560] Cal Advocates Opening Brief at 79.

[561] Cal Advocates Opening Brief at 77-79.

[562] Cal Advocates Opening Brief at 81.

[563] TURN Opening Brief at 309-310; TURN Reply Brief at 75.

The Commission finds that PG&E does not fully address Cal Advocates' persuasive recommendations for the number of meter location remediations by category. In addition, such meter location remediation is not required by any regulation and is not ranked highly in terms of its cost-effectiveness or RSE score. Accordingly, for Meter Protection Program expenses tracked in MAT EXB, the Commission bases its forecast on a projected total of 15,421 meter locations based on the recommendation of Cal Advocates. Accordingly, based on a projected unit a unit cost of $821 per location, the Commission adopts $12.660 million for 2023 expense forecast for costs tracked in MAT EXB.[564]

3.7.3.2. Meter Protection Program (Capital MAT 27A)

The capital cost of relocating meters in the Meter Protection Program is tracked in the Relocation of Meter Sets Program (MAT 27A). PG&E states that the purpose of this program is two-fold: (1) meter protection through the re-location of the meter set; and (2) relocating the meter set due to an inaccessible service valve. PG&E forecasts 250 capital units to be completed in 2023. For 2023, PG&E's forecast for capital expenditures in Relocation of Meter Sets Program (MAT 27A) is $7.245 million.[565]

TURN recommends a reduced expense forecast of $2.066 million for MAT 27A based on a projected 184 units.[566] TURN states that its recommendation matches its recommendation for slowing the pace of the expense Meter Protection Program (MAT EXB).[567]

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[564] Cal Advocates Opening Brief at 76.

[565] PG&E Opening Brief at 278.

[566] TURN Opening Brief at 310.

[567] PG&E Opening Brief at 278-279; TURN Opening Brief at 308-311.

In the 2020 GRC, the Commission found similar claims by PG&E to be insufficient to support its forecast for reducing the backlog of meter remediation. As argued by the same parties in the 2020 GRC, the AOC backlog began being identified in 2014 but PG&E did not commence any remediation work to address that backlog until the 2020 rate case. PG&E has similarly not met its burden of justifying its meter remediation backlog in this case.[568] Slowing the pace and cost of this program is warranted due to the extremely low risk posed by existing gas meters needing protection from potential vehicular damage. Of the three forecasts, the Commission finds the slower pace of remediation adopted to be the most persuasive and supported because it will give the Commission and PG&E more time to consider how this effort fits into the gas long-term planning, before a large additional investment in meter protection is completed. Accordingly, the Commission adopts a 2023 expense forecast for the Meter Protection Program (MAT 27A) of $5.332 million based on 184 meter units at the same cost per meter for PG&E's 2023 forecast and number of units.[569]

3.8. Gas Operations Corrosion Control

PG&E states that is Corrosion Control Programs identify and mitigate the threats of corrosion to PG&E's Gas Transmission pipelines, Gas Distribution mains, storage, and other facilities. Corrosion is an electrochemical process where metal degrades due to its interaction with the environment. The loss of metal is caused by the presence of an electrolyte, such as water, and electrical current sources located near pipelines. PG&E explains that it mitigates internal corrosion by monitoring gas inputs to ensure that electrolytes are not introduced

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568 Cal Advocates Reply Brief at 34.

569 $7.245/250x184=$5.332 million.

into PG&E's pipeline system and by using gas treatment facilities to remove electrolytes from natural gas supplies. To mitigate the threat of external corrosion, PG&E states it uses coating systems to isolate the pipe from electrolytes that are present in the area surrounding the pipe. For pipeline segments that cannot be visually inspected because they are buried or submerged, PG&E explains that it also uses Cathodic Protection, a process that protects steel pipe against electrolysis by the attachment of sacrificial anodes.[570]

PG&E's Corrosion Control Program and its capital expenditure requests and expense forecasts are based on PG&E's assessment of these threats and PG&E's plans to reduce these risks.[571] Two of the 27 expense maintenance activity types related to corrosion control and four of the 11 capital types are disputed.

3.8.1. Atmospheric Corrosion Mitigation of Gas Distribution Mains (MAT FHL)

PG&E states that the Atmospheric Corrosion Mitigation of Gas Distribution Mains program mitigates deficient coating systems identified during atmospheric corrosion inspections of steel pipe distribution mains. Typical mitigation projects include coating repair replacement. PG&E request a 2023 expense forecasts of $3.184 million to mitigate 145 Gas Distribution main spans that were identified during 2020 inspections. The forecast represents an increase of approximately $2.7 million compared to 2020 recorded costs and an increase of 117 spans compared to 2020 recorded units. PG&E states that the increase in forecast units and dollars, as compared to 2020, is primarily due to the discovery of additional spans from the 2020 Atmospheric Corrosion Span

[570] D.19-09-025 at 183.

[571] PG&E Opening Brief at 279.

Inspection Project (MAT FHK).[572] PG&E states that it determined the 2023 unit cost for these inspections using the average unit cost from 2018-2020 and escalating it.

Cal Advocates recommends a forecast of $1.209 million based on a projected 108 mitigation projects in 2023 using the 2021 mitigation rate of 15% because, according to Cal Advocates, it accounts for the most recent mitigation repairs.[573]

PG&E states that Cal Advocates use of 108 mitigation projects in calculating an expense forecast for 2023 is too low because: (1) Cal Advocates' recommended 2023 main mitigation rate incorrectly assumes that atmospheric corrosion inspections and remediations are conducted in the same year, whereas the vast majority of PG&E's atmospheric corrosion remediation projects occur in the third year following the atmospheric corrosion inspections (i.e., 2023 span remediation projects were identified during 2020 span inspections);
(2) Cal Advocates acknowledges that PG&E identified an additional 532 spans following a records research project but does not consider the impact of this effort in its unit forecast; and (3) Cal Advocates relies on 2021 recorded data that was not available when PG&E submitted its 2023 GRC.[574] The Commission finds PG&E's explanation of the number of its mitigation projects reasonably supports its forecast.

With regard to unit costs, PG&E's 2023 unit cost forecast of $21,961 is based on the average unit cost for this workstream for the period 2018-2020,

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[572] PG&E Opening Brief at 281.

[573] Cal Advocates Opening Brief at 86-90.

[574] PG&E Reply Brief at 249-250.

escalated to 2023, while Cal Advocates recommends utilization of a calculated partial-year 2021 unit cost ($11,231) without escalation for 2023.

The Commission finds the use of a three-year average unit cost is the more appropriate methodology to calculate representative unit costs over time and considers year-to-year cost variations associated with projects completed across PG&E's service territory. Accordingly, the Commission adopts PG&E's expense forecast of $3.184 million in 2023 based on work to mitigate a projected 145 Gas Distribution main spans (MAT FHL).

3.8.2. Gas Distribution Atmospheric Corrosion Mitigation Services (MAT FHM)

PG&E states that its Gas Distribution Atmospheric Corrosion Mitigation Services mitigate deficient coating systems identified during atmospheric corrosion inspections of steel service spans and service risers. Typical mitigation projects include coating repair or coating replacement. In instances where significant corrosion is encountered, replacement of service risers may also be performed. PG&E requests a 2023 expense forecast of $1.6 million to mitigate 1,822 standard historic units (coating repair, coating replacement, and riser replacement) and an additional $10.7 million to mitigate 55,000 new units associated with expanded remediation requirements for service risers at the soil-to-air interface. PG&E's unit forecast for service riser coating remediation at the soil-to-air interface, 55,000 units, was based on an engineering estimate of a 5% find rate applied to PG&E's approximate 1.1 million annual service riser inspections.[575]

Cal Advocates recommends a lower forecast of $3.924 million for the work tracked in MAT FHM, which is $8.348 million less than PG&E's request, claiming

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[575] PG&E's total forecast is $12.272. PG&E Opening Brief at 284-285.

that PG&E has not met its burden to support its request for service riser units. Cal Advocates calculated its $3.924 million forecast by adjusting PG&E's November 30, 2021-recorded expense amount of $3.597 million[576] to include an estimate of December expenses for the repair of 24,366 units.[577]

PG&E states that it demonstrated that its forecast for MAT FHM is reasonable. First, since PG&E did not implement the expansion of service riser remediation requirements to include coating damage at the soil to air interface until March 2021, the 2021 recorded costs used by Cal Advocates do not represent a full year of service riser remediation at the soil to air interface. Second, PG&E used an engineering estimate that 5% of future inspections would result in service risers requiring remediation under the new requirements. PG&E maintains that this was appropriate since the 2021 data that Cal Advocates relies on was not available when PG&E prepared its forecast in 2021, and in any event 2021 data is not representative of the future rate of riser repair. Finally, PG&E states that Cal Advocates' recommendation to adopt the 2021 recorded adjusted expense amount of $3.9 million for 2023 does not provide for standard annual cost escalation.[578]

For all these reasons, the Commission finds that PG&E's projection for 55,000 service riser coating remediations at the soil-to-air interface is reasonable based on an engineering estimate of a 5% find rate applied to PG&E's approximate 1.1 million annual service riser inspections. Accordingly, the Commission adopts PG&E's forecast of $12.272 million: $1.6 million in 2023 to mitigate a project 1,822 standard historic units (coating repair, coating

[576] ($327,000 = 1/11th of $3.597 million).

[577] Cal Advocates Reply Brief at 84 to 86.

[578] PG&E Reply Brief at 251-253.

replacement, and riser replacement) and an additional $10.7 million to mitigate a projected 55,000 new units associated with expanded remediation requirements for service risers at the soil-to-air interface.

3.8.3. Corrosion Control (Capital MAT 50D and MAT 50Q)

PG&E explains that loss of electrical isolation between a gas pipe casing and gas piping can divert cathodic protection current and increase the risk of external corrosion. PG&E state that it monitors each cased distribution crossing annually and investigates anomalous conditions to determine whether remedial action is required to mitigate the risk of external corrosion created by the contact between the casing and gas piping. Such corrosion control work for Gas Distribution includes contacted casing remediation of casing spans over 100 feet. Historically, PG&E states that casings over 100 feet were mitigated by work tracked in MAT 50D. PG&E states that, effective, January 1, 2021, PG&E transitioned this work to MAT 50Q.

PG&E's forecast for Gas Distribution casing mitigation over 100 feet (MAT 50D and MAT 50Q) is $4.026 million in 2023.[579] Cal Advocates accepts PG&E's 2023 forecast.[580] Accordingly, the Commission adopts PG&E's 2023 expense forecast for Gas Distribution casing mitigation over 100 feet (MAT 50D and MAT 50Q) of $4.026 million.

Cal Advocates recommends that PG&E's 2021 data be reduced by $4.5 million to $10.9 million, and that the PG&E's 2022 data be reduced by $8.7 million to $10.9 million based on PG&E's 2021 recorded expenditures for a

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579 Cal Advocates Opening Brief at 90 *citing to* PG&E Ex-03 at WP 9-46.

580 Cal Advocates Opening Brief at 90-93; PG&E Opening Brief at 286-289.

number of reasons.[581] Recorded expenditures in 2016 for as the Capital Casing Mitigation Program (MAT 50D) did not exist until 2017, and during 2017-2019 this program transitioned from development in 2017 to full scale during 2020-2022.[582] However, Cal Advocates did not dispute that PG&E's full 2021 data provided on March 9, 2022, shows $12.288 million for MAT 50D/50Q. Accordingly, for modeling purposes, the Commission adopts $12.288 million for the 2021 cost for MAT 50D/50Q.

Cal Advocates recommends that PG&E's 50Q recorded data be reduced for 2022 because Cal Advocates contends that PG&E appears to be underperforming and that PG&E does not explain how it is possible for PG&E to complete forecasted backlog projects by 2022, especially since federal regulations do not indicate a deadline for compliance by then.[583] In response, PG&E claims that the data cited by Cal Advocates is not indicative of PG&E's ability to perform work, but due to COVID-19 impacts in the first half of the 2020-2022 rate case cycle.[584] Considering both parties' arguments and in the absence of 2022 recorded costs in the evidentiary record, the Commission finds insufficient evidence to revise PG&E's 2022 forecast for the Capital Mitigation Program now being tracked in MAT 50Q and adopts PG&E forecast for MAT 50Q of $19.530 million in 2022 for 2023.

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581 Cal Advocates Opening Brief at 91-92.

582 Cal Advocates Opening Brief at 91.

583 Cal Advocates Opening Brief at 92-93.

584 PG&E Opening Brief at 256.

3.8.4. Gas Transmission & Storage Corrosion Control (Capital MATs 3K1, 3K4, 3K9)

PG&E forecasts $12.026 million for its Internal Corrosion Program (Capital MAT 3K1), $11.721 million for its AC Interference Program (Capital MAT 3K4), and $10.441 million for its DC Interference Program (MAT 3K9) for 2021. No party disputed 2022 and 2023 forecasts for these programs.[585]

For GT&S Corrosion Control capital expenditures (Capital MAT 3K1, MAT 3K4, and MAT 3K9) in 2021, Cal Advocates initially recommended a reduction in the forecast for 2021.[586] PG&E responded that 2021 forecasts should be replaced with the more recently available recorded 2021 costs, at which point, Cal Advocates stated that it does not object to the Commission adopting PG&E's 2021 recorded expenditures for MATs 3K1, 3K4, and 3K9.[587]

The Commission finds reasonable the use of the 2021 recorded costs for expenditures for MATs 3K1, 3K4, and 3K9. Accordingly, the Commission adopts forecasts for PG&E's Internal Corrosion Program (Capital MAT 3K1) of $1.342 million, for PG&E's AC Interference Program (Capital MAT 3K4) of $3.310 million, and for PG&E's DC Interference Program (MAT 3K9) of $7.411 million for 2021

3.9. Gas Operations Leak Management

PG&E's Leak Management programs consist of gas leak surveys, grading, repairs, and gas service and main replacements when needed to remediate gas leaks. Its scope includes all engineering, materials, and labor for Leak Management work. PG&E's Leak Management programs mitigate safety and

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585 PG&E Opening Brief at 289.

586 PG&E Opening Brief at 289.

587 PG&E Reply Brief at 257; Cal Advocates Opening Brief at 93 and 95.

reliability risks on the Gas Distribution system, and the GT&S system, as well as reducing GHG emissions. In 2020, PG&E's Leak Management teams surveyed over 1.4 million Gas Distribution services and over 13,000 miles of Gas Transmission pipeline, identified 26,513 gradable distribution gas leaks and 4,012 gradable GT&S gas leaks, and repaired 21,251 gradable distribution gas leaks and 3,503 gradable GT&S gas leaks. Three of the 23 expense Maintenance Activity Types related to Leak Management and one of the capital types discussed below are disputed.[588]

3.9.1. Below Ground Distribution Main Leak Repair (MAT FIG)

PG&E's states that its Below Ground Distribution Main Leak Repair includes work repairing leaks on Gas Distribution mains in accordance with federal regulations.[589] Regarding the 2023 expense forecasts for this work, parties made adjustments to forecasts in their opening briefs. PG&E forecasts $33.715 million in expenses in 2023 for work tracked in MAT FIG, and Cal Advocates recommends an expense forecast of $27.99 million, a reduction of $5.725 million.[590] Cal Advocates' lower recommendation is based on a lower leak find rate and a lower unit cost per repair than PG&E's forecast.

3.9.1.1. Below Ground Distribution Main Leak Rate

PG&E determined a 2.04% leak find rate for below-ground leaks using the following analysis. PG&E's leak "find rate per 1 thousand services surveyed" for each leak grade is based on a blend of 2018-2020 June year-to-date (YTD) actuals

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588 PG&E Opening Brief at 290-291.

589 PG&E Opening Brief at 292.

590 Cal Advocates Reply Brief at 37-38.

broken down by division.[591] Using these find rates, PG&E projects the leak find volume in 2023 for each type of leak – above-ground grade 1, 2, and 3 leaks and below-ground grade 1, 2, and 3 leaks. PG&E then added the forecast call-in leaks found from customer odor complaints. Finally, PG&E summed up the leaks forecast from these calculations and obtained a total 2023 forecast leak volume of 27,739. This total, divided by the total leak survey volume of 1,361,716 units, yields PG&E's overall find rate of 2.04%.[592]

Cal Advocates recommends a leak-find rate of 0.84% based on PG&E's records of the number of services and mains surveyed annually from 2016 to 2021.[593] Cal Advocates claims that this data reflects a leak find rate that has declined from 4.3% in 2019 to 0.84% in 2021.[594]

In response, PG&E states that Cal Advocates' calculation is inaccurate because: (1) Cal Advocates relied on 2021 data not available to PG&E when it developed its forecast; (2) Cal Advocates' calculations used partial-2021 data even though PG&E provided full 2021 recorded data in March 2022, long before Cal Advocates' testimony was submitted; (3) by utilizing a single year for its forecast calculation, Cal Advocates' recommendation only provides leak rate information for one third of PG&E's Gas Distribution system because PG&E's leak survey covers the entire system every three years, and using a single year of data does not provide a true representation of the historical average find rate; and (4) Cal Advocates' leak find rate does not include a volume of leaks found

[591] PG&E Opening Brief at 292.

[592] PG&E Opening Brief at 293-294.

[593] PG&E Ex-03 at 10-16.

[594] Cal Advocates Opening Brief at 100-101.

due to call-ins from customer odor complaints.[595] The parties dispute whether the volume of leaks found includes customer complaints.

Considering all the evidence, the Commission finds that PG&E's data is more thorough and complete, and therefore, finds by a preponderance of the evidence that PG&E's leak rate of 2.04% is more persuasive and adopts it for purposes of establishing a reasonable forecast in this proceeding.

3.9.1.2. PG&E's 2023 Forecasted Leak Repair Unit Cost

PG&E's 2023 forecasted unit cost for leak repairs is based on 2020 recorded costs plus a 3.75% escalation due to annual Internal Brotherhood of Electrical Workers (IBEW) wage increases. PG&E proposes basing its forecast on 2020 recorded costs because it is the base year consistent with the Commission's Rate Case Plan described in Section 1.5, herein.[596] This produces a unit cost of $8,871.[597]

Cal Advocates' unit cost forecast is based on 2021 recorded costs divided by 2021 recorded leak repairs as of November 30, 2021. Cal Advocates recommends using the 2021-unit cost of $8,193 per unit as a basis for the 2023 forecast because it is based on more recent data and it produces a unit cost that is lower than PG&E's of $8,871.[598] Cal Advocates argues that its unit forecast should be adopted because it represents the 2021 average unit cost and compares closely with recent recorded average costs.

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[595] PG&E Reply Brief at 259-260.

[596] PG&E Opening Brief at 293-294.

[597] PG&E Reply Brief at 262-263.

[598] Cal Advocates accounted for the 3.75% escalation due to annual Internal Brotherhood of Electrical Workers (IBEW) wage increases in its opening brief; Cal Advocates Opening Brief at 100-101.

As described in Section 1.5, herein, the Commission's ratemaking principles seek to balance ratemaking goals designed to facilitate a thorough, effective and expeditious ratemaking process. As such the Commission balances its interest in using recent data with other broader ratemaking principles. For this forecast, Cal Advocates uses 2021 data which was not available at the time of filing and does not comprise a full year of data. Other than the 11 months of 2021 data being more recent, the Commission does not find a sufficient reason to depart from the use of the base year of 2020 recorded costs for this forecast. Accordingly, for the unit cost for leak repairs (MAT FIG) the Commission finds persuasive a unit cost forecast of $8,871 for purposes of establishing a forecast in this proceeding. As a result, for the Below Ground Distribution Main Leak Repair Program work (MAT FIG), the Commission adopts an expense forecast for 2023 of $33.715 million.

3.9.2. Distribution Meter Set Leak Repair (MAT FIS)

PG&E states that Meter Set Leak Repair is the work to repair non-hazardous leaks on gas meter sets. Repair of non-hazardous meter set leaks within 36 months is required pursuant to PG&E's internal work and compliance matrix. PG&E projects 139,749 meter repairs in 2023 at a total forecasted expense of $16.209 million.[599] Cal Advocates recommends a lower forecast of $7.536 million based on a lower number of repair units and a lower unit cost per repair compared to PG&E's proposal.[600]

[599] PG&E Opening Brief at 294-295.

[600] Cal Advocates Opening Brief at 101-104.

3.9.2.1. Annual Meter Set Leak Repairs for MAT FIS

PG&E's estimate of 139,749 meter repairs in 2023[601] represents a 110% increase in the number of repairs performed.[602] PG&E states that the increase represents the company's effort to reduce the pending backlog of approximately 70,000 pending non-hazardous meter set leaks repairs and preventing the backlog from continuing to grow.[603] PG&E characterizes this as backlog, but also stated that pending units represent the backlog of units left open at the end of a given year.[604] PG&E's find and repair rates are based on a three-year average (2018 to 2020 through June) that it claims is more accurate than Cal Advocates' methodology.

Both PG&E and Cal Advocates base their 2023 forecasts on the historical number of find and repairs per year. However, the estimation is complicated by the combination of sets of meter set leaks and riser thread leaks and PG&E's transfer of data from MAT FIH to MAT FIS.[605]

Cal Advocates proposes developing a forecast based on continuing meter repair at the historic level. Cal Advocates estimates this level based on a single year of data as a total repair rate of 68.46%, which includes a rate of 59.54% for meter set leaks and 8.65% for riser thread leaks. This equates to a total of 69,285 repairs — 60,645 meter set leak repairs and 8,641 riser thread repairs.[606]

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[601] PG&E Reply Brief at 263.

[602] Cal Advocates Opening Brief at 102.

[603] PG&E Reply Brief at 264-265.

[604] PG&E Opening Brief at 295.

[605] Cal Advocates Opening Brief at 102-103.

[606] Cal Advocates Opening Brief at 103.

In summary, PG&E states that Cal Advocates' unit forecast is similar to past repair rates but would allow the backlog of pending meter set leak volume to continue to grow year over year, which PG&E is trying to avoid by proposing an increased forecast. Cal Advocates claims year-to-year pending leaks are managed as part of PG&E's normal operation and do not warrant an escalated repair level in the test year.[607] In response, PG&E states that Cal Advocates' position only makes sense if adequate funding is granted.

The Commission finds that costs tracked in MAT FIS represent a routine maintenance program that needs additional funding to keep up with meter set leak repairs and avoid an unmanageable ballooning of the backlog of unaddressed leaks.[608] Considering affordability issues presented by PG&E's overall request in this proceeding, the Commission finds that 80,000 is a reasonable estimate for purposes of developing a forecast and balanced level of annual meter set leak repairs (MAT FIS) for 2023 through 2026.

3.9.2.2. Meter Set Leak Repair (MAT FIS) Unit Cost

PG&E's projected unit cost for meter set leak repairs used for purposes of developing its 2023 expense forecast represents a 133% increase above the base year and is based on a combination of costs to repair meter set leaks, and the cost to repair riser thread leaks, broken down by field services and maintenance and construction. Meter set leak repair costs are based on 2019, not 2020, recorded data due to the impacts on 2020 costs caused by job delays due to State-mandated COVID restrictions. Riser thread repair costs are calculated separately because cost per unit is higher due to some of the repairs requiring

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[607] Cal Advocates Reply Brief at 104.

[608] PG&E Reply Brief at 265.

maintenance and construction repair support and are based on a 2018-2020 year-to-date June historical average.

Cal Advocates recommends using the 2021 PG&E meter set repair unit cost and riser thread repair unit costs to forecast the two different cost elements because it reflects the most recent cost data. Cal Advocates states that this equates to a 2021-unit cost for meter set repair of $110.29 and a unit cost for riser thread repair of $98.08 and claims such costs are lower than PG&E's request of $115.98 for the 2023 unit cost.[609] But PG&E's forecasted unit cost is based on a combination of costs to repair meter set leaks, and the cost to repair riser thread leaks.[610]

In response, PG&E disputes Cal Advocates' approach because "it does not take into consideration a full years' work" and "uses 2021 data which was not available at the time PG&E filed on June 30, 2021."[611] Cal Advocates argues that PG&E had the opportunity to provide full 2021 data in its rebuttal testimony and should base its forecasts on the most up-to-date information.[612]

The Commission finds that, as with the unit cost for MAT FIG above, Cal Advocates does not provide a convincing rationale for updating the data to 2021. In addition, the Commission finds Cal Advocates' forecast unpersuasive because is not based on a full year of data. Accordingly, the Commission adopts PG&E's unit forecast for meter set leak repairs (MAT FIS) of $115.98 for purposes of establishing a forecast, resulting in an adopted expense forecast for meter set leak repairs (MAT FIS) for 2023 of $9.278 million.

[609] Cal Advocates Opening Brief at 104.

[610] PG&E Reply Brief at 266.

[611] PG&E Reply Brief at 266.

[612] Cal Advocates Opening Brief at 104.

3.9.3. Below Ground Distribution Service Replacement (MAT 50G)

PG&E's Below Ground Gas Distribution Service Replacement program works to replace or deactivate Gas Distribution services due to leaks in accordance with federal regulations.[613] For this work, PG&E now requests a total of $14.400 million in 2023 capital expenses tracked in MAT 50G, reflecting a post-February 28, 2022 forecast reduction of $7.3 million from its original request and $2.3 million lower than Cal Advocates' original recommendation of $16.7 million.[614] The reduction is due to correction of an error in the use of historical MAT code splits used to determine the leak repair forecast, resulting in a 2023 unit forecast of 978 rather than 1,476.[615]

Because Cal Advocates does not contest the updated forecast, the Commission finds PG&E's updated amount reasonable. Accordingly, the Commission adopts PG&E's updated forecast for PG&E's Below Ground Gas Distribution Service Replacement program for 2023 of $14.400 million.

3.9.4. Transmission Leak Repair (MAT JOP)

PG&E states that Transmission Leak Repair is the work to repair leaks on Gas Transmission facilities. PG&E's Transmission Leak Repair complies with the requirement from the Commission's Leak Abatement Rulemaking Best Practice 21, which requires PG&E to repair all leaks "as soon as reasonably possible after discovery, but in no event, more than three years after discovery."[616] The intent of Best Practice 21 is to exceed the requirements in the

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[613] PG&E Opening Brief at 298 *citing to* PG&E Ex-03 at 10-33.

[614] Cal Advocates Opening Brief at 106.

[615] PG&E Reply Brief at 267.

[616] D.17-06-015, Decision Approving Natural Gas Leak Abatement Program Consistent with Senate Bill 1371 at 89.

Commission's General Order (GO) 112-F, which does not have a repair deadline for above ground Grade 3 leaks.[617] The 2017 mandate to repair leaks more quickly has increased PG&E's repair forecast from 1,592 completed in 2017-2021 to 3,281 repairs. As a result, PG&E forecasts an increase in expense to $13.210 million for 2023.[618]

Cal Advocates disagrees with PG&E's above-ground Grade 3 leak unit forecast. TURN recommends adopting a five-year average (2016-2020) unit cost instead of PG&E's proposed two-year average (2019-2020) unit cost.[619] The disputed issues are addressed below.

3.9.4.1. Forecast of Grade 3 Transmission Leak Repairs

PG&E's 2023 above ground Grade 3 leak repair forecast is based on an estimate of active open leaks in 2020 that must be repaired within three years, i.e., in 2023. Cal Advocates recommends a "forecast that recognizes 1/3 of the open above ground Grade 3 leaks (159 out of 476 leaks) PG&E identified for 2020 to develop its 2023 forecast." Cal Advocates excluded 2018 and 2019 leaks arguing that PG&E should have already resolved them by 2023.

In response, PG&E stated that its 2023 forecast includes the known active open Grade 3 above ground leaks from 2020 multiplied by two to account for the second half of the year. At the time PG&E developed its rate case forecast, PG&E states that only data for 2020 YTD June was available and that PG&E is not including leaks from 2018 and 2019 in its 2023 forecast. As shown in PG&E's workpapers, the 2023 above ground Grade 3 forecast is based on active above

[617] Cal Advocates Reply Brief at 39.

[618] PG&E Opening Brief at 300.

[619] PG&E Opening Brief at 300.

ground Grade 3 leaks from 2020 and not 2019. Moreover, by using the 2020 year-to-date June above ground Grade 3 leak count, Cal Advocate's calculation does not take into consideration leaks found in the second half of 2020 that will require repair by 2023. Consequently, PG&E states that Cal Advocates significantly understates the above Ground Grade 3 leak count for 2020.[620]

Based on the evidence and argument above, the Commission finds that PG&E has met its burden to demonstrate that its forecast of Grade 3 Transmission Leak Repairs is reasonable and the Commission adopts PG&E's 2023 forecast of 1,902 above ground and below ground Grade 1 and 2 leaks and 903 Grade 3 above ground leaks (427 + 476) for a total of 2805 leak repairs for purposes of establishing a cost forecast for this proceeding.[621]

3.9.4.2. Transmission Pipe Leak Repair Unit Cost

PG&E states that its 2023 forecasted unit cost for Transmission Pipe Leak Repair is based on a two-year average, 2019-2020, plus a 3.75% escalation rate due to increases in IBEW annual wages. PG&E states that its two-year average aligns with the operational change that took place in 2019 where the leak survey work transitioned from Gas Pipeline Operations Maintenance to the Leak Survey team. Previously, Gas Pipeline Operations Maintenance leak repairs were captured as part of routine corrective maintenance under the work tracked in MWC JP.[622]

TURN proposes a reduction of $1.25 million in expenses by using a five-year weighted average (2016-2020) to calculate the unit cost, given the

[620] PG&E Reply Brief 268-269.

[621] Cal Advocates Reply Brief at 39 -40.

[622] PG&E Opening Brief at 301-302.

significant uncorrelated variability in historical unit costs. PG&E argues that a unit cost based on a shorter two-year average (2019-2020) is more appropriate because (1) the requirement to repair Grade 3 leaks within 36 months was not in effect until 2017, and (2) in 2019, leak repairs transitioned from the gas pipeline operations maintenance team to the leak survey team, thus "resulting in higher leak find rates."[623]

The Commission finds that the information provided by PG&E does not fully explain why the cost per Transmission Pipe Leak Repair changed from $6,785 in 2016, dropped to $2,115 in 2018, and increased to over $3,650 in 2019 and 2020 when the number of repairs increased.[624] As a result, the Commission finds TURN's recommendation persuasive and, for purposes of establishing a cost forecast in this proceeding, adopts TURN's unit cost forecast for Transmission Pipe Leak Repair based on the five-year average of the unit cost of $3,291.00, instead of a two-year average suggested by PG&R. Based on these findings, the Commission adopts a 2023 expense forecast of $9.231 million for Transmission Pipe Leak Repair.

3.10. Gas System Operations

PG&E states that its Gas System Operations function is responsible for maintaining sufficient design day capacity on the system, and for planning and operating the Gas Distribution and GT&S system. The Gas System Operations forecast also includes engineering for local Gas Distribution facilities and activities related to the manual operation of gas facilities in the field.[625] Four of

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[623] TURN Reply Brief at 76.

[624] TURN Reply Brief at 76-77.

[625] PG&E Opening Brief at 302-303.

the 11 expense maintenance activity types and three of the 10 capital types are disputed.

3.10.1. Gas Distribution Control Center Operations (MAT FGA)

PG&E states that its Gas Distribution Control Center Operations enables Gas System Operations to mitigate operational risk by integrating operations, capacity planning, integrity management, maintenance, and repairs into a highly coordinated effort that is monitored and supervised from a single location. It enables system operators, who staff the Gas Distribution Control Center Operations 24 hours a day, seven days a week, to remotely monitor the Gas Distribution system, including key equipment, and to respond quickly to mitigate events that could occur. Activities under Gas Distribution Control Center Operations also include control room management compliance, technology maintenance (including Supervisory Control and Data Acquisition (SCADA) and control console interfaces), and operations engineering.[626]

PG&E requests a 2023 expense forecast of $8.838 million for Gas Distribution Control Center Operations, which is work tracked in MAT FGA. Cal Advocates recommends a lower amount of $8.481 million. PG&E's request represents a $1.2 million increase over the 2020 recorded expenses due to costs of PG&E's proposed control room consolidation and SCADA Predictive Health Analytics project. Cal Advocates recommends $.357 million less than PG&E on the basis that PG&E fails to prove that certain costs remain necessary in this rate case period (2023-2026).[627]

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[626] PG&E Opening Brief at 304.

[627] Cal Advocates Opening Brief at 107.

3.10.1.1. Costs Associated With PG&E's Consolidation Plan

PG&E states that it allocated $0.078 million for consolidation activities to train Distribution and Transmission Control System employees to operate both systems. However, the proposed consolidation will no longer occur. Members of IBEW voted against adopting the consolidation plan, so PG&E "will continue to operate the gas system under the current distribution transmission structure." Nevertheless, PG&E claims that it needs to "backfill approximately six additional gas control operators and supervisors that were left vacant in preparation for implementation of the Gas Control Room Consolidation Plan." PG&E expects that backfilling these positions "will exceed the incremental cost forecast" originally presented to the Commission. Cal Advocates states that PG&E fails to provide a workload study, a breakdown of salaries, or additional evidentiary support for the need and cost of these employees. For this reason, Cal Advocates argues that PG&E's request of $0.078 million for consolidation activities should be denied.[628]

In response, PG&E states that its work papers contain information that allows the incremental cost of hiring the additional Gas Control employees to be estimated. PG&E states that the approximate annual cost of backfilling the six additional gas control operator and supervisor positions is $1.586 million and can be calculated by taking the fully-burdened cost for a Gas Control employee and by multiplying that cost by the six FTEs to be hired. In addition, PG&E claims that the $1.586 million annual cost of hiring six additional Gas Control

[628] Cal Advocates Opening Brief at 107-108.

employees is nearly three times the cost of the 2021 Gas Control Consolidation forecast of $559,556.[629]

The Commission finds that whether or not the full amount of the $1.586 million forecast is needed remains a reasonable question in light of the record. The Commission expects PG&E to justify its future increases in forecasts with sufficient detail. In this case a workload study and a breakdown of salaries would provide additional evidentiary support for the need and cost of these employees. Because PG&E has not supported its request by the preponderance of evidence, the Commission is persuaded by Cal Advocate' arguments and finds Cal Advocates' recommended disallowance of $0.078 million for consolidation activities that never occurred to be reasonable.

3.10.1.2. The SCADA Predictive Health Analytics Work

PG&E states that it allocates $0.279 for incorporation of SCADA Predictive Health Analytics in 2023. According to PG&E, "[t]his work has historically been adopted in prior rate cases and funded as part of ongoing Information Technology projects, since the tools and predictive health methodologies to mine the data were continuously being developed and modified."[630] In this rate case, however, PG&E presented its forecast for this work in different accounting codes — it was historically presented in MAT codes JVA and 2FA and is now presented in MAT codes FGA and CMA. Cal Advocates argues that PG&E fails to explain why it modified the accounting codes for this work activity. Such modification adds a level of complexity to already-complicated GRC applications and makes it more challenging for the Commission and parties to compare

629 PG&E Reply Brief at 272-273.

630 PG&E Ex-16-E (Rebuttal) at 11-14 to 11-15.

historic costs with future forecasts. Cal Advocates states that, because PG&E has failed to support its accounting cost transfer or explain why current funding for this project is insufficient, the Commission should deny PG&E's request.[631]

In response, PG&E states that Cal Advocates misunderstands the nature of the Supervisory Control and Data Acquisition (SCADA) Predictive Health Analytics program that is now part of Gas Distribution Control Center Operations arguing this is not new or additional work, but merely a shift to MAT FGA of existing work previously charged to other MAT codes. The SCADA Predictive Health Analytics was forecast as part of the 2019 GT&S rate case and the 2020 GRC in MAT JVA and MAT 2FA as a technology project. In preparing the 2023 rate case forecast, PG&E presented the forecast for SCADA Predictive Health Analytics in MAT FGA (GDCC) and MAT CMA (GTCC) instead of forecasting the costs in MAT JVA or MAT 2FA. The forecast presented in the 2023 rate case is simply an accounting cost transfer for continuing activities and is not a new program to the GRC. PG&E is not forecasting any incremental headcount additions to perform SCADA Predictive Health Analytics work during this rate case period.[632]

The Commission agrees with Cal Advocates that PG&E's modification of accounting codes for its forecasts adds complexity to PG&E's rate case applications that requires better explanation in its initial application rather than waiting to provide it in rebuttal testimony, answers to data requests, and reply briefs. The Commission requires greater transparency and more thorough documentation of forecasts in future applications. Nevertheless, the Commission

[631] Cal Advocates Opening Brief at 108.

[632] PG&E Reply Brief at 307-308.

finds PG&E's forecast for SCADA Predictive Health Analytics Work in MAT FGA to be supported. The forecast presented here is an accounting cost transfer for continuing activities and is not new work. For Distribution Control Center O&M expenses for 2023 tracked in MAT FGA, the Commission reduces PG&E's forecast by $0.078 million and adopts a 2023 expense forecast of $8.760 million.

3.10.2. Gas Distribution Manual Field Operations (Expense MAT FGB)

PG&E states that the Gas Distribution Manual Field Operations must be performed from time to time to connect and calibrate pressure test gauges and portable pressure recorders, to retrieve and replace paper charts from the recorders, to remove incidental pipeline liquids, and to perform similar activities. Furthermore, PG&E explains that when system demands are high, and to deal with other abnormal situations, personnel may be dispatched to operate certain field equipment manually.[633]

PG&E requests a 2023 expense forecast of $1.056 million for Gas Distribution Manual Field Operations, which is work tracked in MAT FGB. This is an increase of $0.1 million over 2020 recorded amounts. Cal Advocates recommends a $0.27 million reduction for the forecast associated with MAT FGB because PG&E's request does not account for the declining trend of expenses for manual field operations. Cal Advocates' recommendation is based on PG&E's recorded expenses of $0.829 million for MAT FGB in 2021. PG&E admits that its expenses have decreased from 2016 to 2021 "due to a decrease in the number of manual field operations that were required to calibrate portable pressure chart

[633] PG&E Opening Brief at 308.

recorders in the field."[634] In fact, PG&E has observed a declining trend of approximately 10% per year on average in MAT FGB recorded expenses during that time period. According to PG&E, as the company "installs more Supervisory Control and Data Acquisition (SCADA) devices that can monitor the gas distribution system remotely, such as Electronic Pressure Recorders (ERXs) and Remote Terminal Units (RTUs), fewer pressure chart calibrations are required."[635] In line with PG&E's SCADA criteria objectives, the company plans to complete 73% of the regulation station SCADA field installations by 2022. Despite acknowledging the declining trend for MAT FGB costs, PG&E argues that its forecast is still correct because "the frequency at which PG&E performs manual field operations is variable and is dependent upon system conditions that include the need to throttle values during peak demand days, to performing site visits after winter storms to ensure asset calibration."[636]

The Commission finds that an analysis of the six-year average (2016-2021) of MAT FGB costs (un-escalated) is $1,113,777, exceeding PG&E's 2023 forecast of $1.056 million and appropriately reflects the declining trend. Furthermore, the recorded costs show that there continues to be variability in these costs. For example, from 2019 to 2020, the costs jumped from $899,000 to $957,000.[637] Therefore, the Commission finds that the continued variability does not support reducing the 2023 forecast so steeply for MAT FGB based on one year of data.[638] Nor does the declining trend reflected in PG&E's data support an increase for

[634] PG&E Opening Brief at 309.

[635] Cal Advocates Opening Brief at 109.

[636] Cal Advocates Opening Brief at 108-109.

[637] PG&E Reply Brief at 274-275.

[638] PG&E Opening Brief at 309.

2023. Accordingly, the Commission adopts the amount of the 2020 recorded amount of $0.957 million for the 2023 expense forecast for MAT FGB.[639]

3.10.3. GT&S Operations (MAT CMA)

PG&E states that GT&S Operations require staff in the Gas Transmission Control Center (GTCC), Gas Scheduling & Accounting, Gas System Planning (GSP) and Gas Operations Control Technology & Integration team to operate the GT&S system, maintain the SCADA and other GTCC systems, support customers using the system, and plan for capacity and operations on a daily and longer-term basis. PG&E's 2023 forecast for MAT CMA is $17.297 million.[640] PG&E is seeking additional funding of $3.6 million over recorded 2020 expenses. PG&E attributes the increase to four key drivers: (1) PG&E's plan for control room consolidation; (2) periodic wage increases for union represented employees; (3) hiring five additional engineers; and (4) inclusion of SCADA Preventative Health Analytics work.[641]

Cal Advocates recommends reducing the forecast for MAT CMA in 2023 by $1.94 million to $15.36 million for several reasons. First, the previously proposed consolidation will no longer occur because IBEW voted to not adopt the consolidation plan. Second, PG&E does not justify its decision to present SCADA analytics work in new accounting codes. Third, the addition of five new employees at an expense of $1.17 million in May 2021 does not support the need for additional funding in 2023. PG&E's expenses tracked in MAT CMA were $13.80 in 2021 and $13.75 million in 2020. Finally, Cal Advocates'

[639] PG&E Ex-03-WP, Ch. 10-13.

[640] PG&E Opening Brief at 309-310.

[641] Cal Advocates Reply Brief at 110.

recommendation of $15.36 million still exceeds the average from 2016-2021 for MAT CMA of $13 million.[642]

In response, PG&E states: (1) its GSP team performed a workload study vs. resources that showed that PG&E's GSP team was projected to be understaffed by 17% by 2021; and (2) the cost of the additional engineers was only incurred for the second half of 2021, representing an incremental cost of approximately $0.5 million.[643]

The Commission finds that PG&E's fails to persuasively support its request for additional funding above the $13.80 million in 2021 to $17.3 million in 2023. Rather, the Commission finds the amount of $15.360 million recommended by Cal Advocates is better supported. Accordingly, the Commission adopts a 2023 expense forecast of $15.360 million for GT&S Operations (MAT CMA).

3.10.4. Electric Power for Compressor Fuel and Other Equipment (MAT CMB)

PG&E states that electric power for compressor fuel and other equipment includes the cost of operating electric-powered gas compressors at Bethany and Delevan compressor stations on the backbone transmission system, the McDonald Island storage facility, and on the local transmission system in Santa Rosa. PG&E further states that MAT CMB also includes the costs for electric power used by SCADA devices, station buildings, and other electric equipment on the transmission system.[644]

PG&E forecasts 2023 expense of $29.125 million for MAT CMB. This forecast is $2.1 million more than in 2020 recorded amounts and above the

[642] Cal Advocates Opening Brief at 110-111.

[643] PG&E Reply Brief at 276-278.

[644] PG&E Opening Brief at 312.

historical average for 2016-2020, which was below $24.5 million. PG&E states that this increase is driven by increased electricity usage and higher electricity costs to run the electric gas compressor stations.[645]

Cal Advocates recommends reducing PG&E's 2023 forecast for work tracked in MAT CMB by $1.625 million to $27.5 million because PG&E has not provided sufficient support for the increase above the historical average. Cal Advocates bases its forecast on the historical average of $24.5 million plus an additional 12.25% to account for increases in fuel and electricity costs.[646]

The historic costs for the five-year average relied on by Cal Advocates are: $20.9 million (2016); $20.4 million (2017); $21.7 million (2018); $24.8 million (2019); and $27.0 million (2020). PG&E claimed that Cal Advocates use of a 2016 to 2020 average was inappropriate because it did not capture the increasing trend.[647]

The Commission finds that the evidence for an increasing trend is contradicted by PG&E's recorded expenses for MAT CMB in 2021 dropping to $24.278 million, which is close to the 2016-2020 historical average of $24.5 million.[648] Consequently, the Commission finds a forecast based on the historical average to be more reasonable and adopts a 2023 expense forecast for MAT CMB of $27.500 million.

645 PG&E Opening Brief at 313.

646 Cal Advocates Opening Brief at 111-112.

647 PG&E Reply Brief at 279.

648 Cal Advocates Opening Brief at 112.

3.10.5. SCADA Visibility Program – Gas Distribution Remote Terminal Units (Capital MAT 4AM) and Gas Transmission (Capital MAT 76M)

PG&E states that its SCADA program sends pressure and flow data to the Gas Distribution Control Center to provide operators with constant monitoring of the gas distribution system. If the devices detect conditions that are out of the normal range, they send an alarm to the Gas Distribution Control Center that is investigated and remediated. PG&E states that data from SCADA devices also helps engineers validate and calibrate hydraulic models leading to more efficient designs and data.

PG&E explains that it operates two basic types of SCADA devices: RTUs and ERXs. RTUs are capable of real time data transmission with multiple sensing capabilities, including pressure transmitters, pressure differential transmitters, switches, and other instruments. RTU units are therefore the most valuable in detecting abnormal conditions in real time and allowing the Gas Distribution Control Center to mitigate unsafe situations. ERX devices are capable of periodic data transmission at fixed intervals with limited sensing capabilities.[649]

For the Gas Distribution SCADA (MAT 4AM) program, PG&E forecasts spending $22.787 million in 2023.[650] PG&E's strategy is to provide 100% visibility into all hydraulically independent systems containing 50 or more customers by 2025 to provide the Gas Distribution Control Center with increased visibility into system performance and allow quicker identification and response to abnormal operating conditions.[651]

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[649] PG&E Opening Brief at 314.

[650] PG&E Opening Brief at 315.

[651] PG&E Reply Brief at 280.

For Gas Transmission lines (MAT 76M), PG&E proposes to install SCADA devices at all transmission regulating stations and compressor stations to enable a high degree of monitoring and control for the GTCC. The installations proposed under this program will improve the GTCC's ability to detect and prevent potential operational issues before they escalate into events, and its ability to mitigate events that may occur despite these preventative efforts. For gas transmission lines, PG&E requests a 2023 expense forecast of $2.778 million (MAT 76M) for funding to install a total of 32 additional SCADA sites (eight per year) on Local Transmission stations between 2023-2026, bringing Local Transmission regulator station visibility from 60% at the end of 2022 to approximately 69% by 2026.[652]

PG&E's justification for installing additional SCADA devices on gas distribution lines (MAT 4AM) and transmission lines (MAT 76M) is similar and summarized as follows: (1) PG&E forecasts installing RTUs at the remaining 297 locations identified to provide 100% visibility into all hydraulically independent systems (HIS) containing 50 or more customers; (2) completing PG&E's SCADA network provides the Gas Distribution Control Center and GTCC the ability to implement a predictive approach to operating the system; (3) only approximately 10%, or 30 locations, out of the remaining 297 forecast SCADA installations on the Gas Distribution system are classified as "low risk;" (4) PG&E's Gas Distribution Control Center SCADA program enhances compliance with state and federal regulations; and (5) installing additional SCADA devices provides the GTCC the situational awareness to identify conditions that may lead to abnormal events, diagnostic capabilities to determine

[652] PG&E Opening Brief at 319.

the cause (e.g., station failure, pipeline capacity constraints, etc.), and the ability to proactively take action to reduce the time to respond and minimize potential impact on customers if they should occur.[653]

TURN recommends discontinuing funding for PG&E's Gas Distribution SCADA (MAT 4AM) Visibility Program and GT SCADA (MAT 76M) Visibility Program because: (1) these discretionary programs have extremely low RSEs and are not cost-effective; and (2) there is relatively little residual risk to be mitigated.[654] To support its recommendation further, TURN adds that PG&E has installed at least one SCADA device at each backbone station, which provides "100 percent visibility for the backbone system." With respect to the local transmission system, PG&E already "has visibility at all large regulator stations;" the proposal here would "extend visibility into smaller systems."[655]

In response, PG&E states that much of the remaining work is necessary to provide complete visibility to larger HISs and complete SCADA equipment installations on smaller and single station HISs to effectively monitor these systems.[656] However, PG&E does not quantify how many larger and smaller HIS's are remaining along with the relative risk reduction benefits of installing additional SCADA systems.

In the last GT&S rate case, PG&E proposed to install a SCADA device every 20 miles on long segments of its backbone transmission system and other high priority pipeline segments, including nine SCADA devices on its backbone transmission system and 26 SCADA devices at regulation stations on its local

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653 PG&E Reply Brief at 281-282, 289.

654 TURN Opening Brief at 320.

655 TURN Opening Brief at 318.

656 PG&E Reply Brief at 286.

transmission system and the Commission adopted a forecast of $10.2 million over 2019-2021 to fulfill these plans.[657] In this rate case, PG&E requests authority to install a total of 32 additional SCADA sites (eight per year) on Local Transmission stations between 2023-2026, bringing Local Transmission regulator station visibility from 60% at the end of 2022 to approximately 69% by 2026. For this number of additional GT SCADA sites, PG&E requests $2.8 million of 2023 capital expense funding. This is less than the forecast authorized in the last GT&S rate case for additional SCADA distribution and transmission sites. The reduction is justified by the low RSE scores for this activity. Accordingly, the Commission adopts a forecast for 2023 for eight additional SCADA devices in this rate case only for gas transmission as tracked in MAT 76M of $2.778 million.

PG&E's forecast for additional gas distribution SCADA devices for 2023 is over six times the previous rate case level authorized for additional gas distribution sites tracked in MAT 4AM. This Gas Distribution SCADA forecast is not supported with the RSE calculations either.[658] Accordingly, the Commission does not adopt PG&E's 2023 expense forecast of $22.787 million for additional Gas Distribution SCADA devices in this rate case, which is work tracked in MAT 4AM.

3.10.6. Gas Transmission Capacity for Load Growth (Capital MAT 73A)

PG&E states that capacity projects install gas transmission facilities to meet non-customer specific demand growth. Examples of capacity projects include constructing new gas pipelines (including parallel lines), increasing regulating station capacity, and adding new regulating stations. PG&E explains that the

[657] D.19-09-025 at 220-221.

[658] TURN Opening Brief at 324; CPUC Resolution WSD-002 at 20.

need for new transmission capacity projects is driven by demand growth from increasing population, higher commercial and industrial loads, and increases in gas usage from factors such as space additions to existing housing.[659]

PG&E forecasts $8.589 million in capital expenditures for capacity projects in 2023.[660] To develop this capacity forecast for work tracked in MAT 73A, PG&E prepared a program level forecast by utilizing a three-year average of recorded costs (2017-2019) and reducing the forecast by 50%. PG&E explains that the 50% reduction represents the level of uncertainty that PG&E has in projects being identified during the 2023 rate case period and reflects the cost necessary to build capacity on an as-identified basis.[661] In addition, PG&E provided estimates for four projects in October 2021 that are in their early planning stages in 2023.[662]

TURN recommends a reduction in the forecast for MAT 73A based on using the three most recent years from 2018-2020 instead of an average of the capacity projects from 2017-2019. Fifty percent of the average of those years produces a reduced forecast of $6.028 million for 2023. TURN contends PG&E could avoid the need for additional transmission capacity entirely by using alternatives such as peak-shaving and use of LNG and CNG support. PG&E accepts that in some areas it is able to leverage these alternatives. At the same

[659] PG&E Opening Brief at 322.

[660] PG&E Opening Brief at 323.

[661] PG&E Reply Brief at 293-294; TURN Opening Brief at 318.

[661] PG&E Reply Brief at 286.

[661] D.19-09-025 at 220-221.

[661] TURN Opening Brief at 324; CPUC Resolution WSD-002 at 20.

[661] PG&E Reply Brief at 293-294; TURN Opening Brief at 315-318.

[662] PG&E Reply Brief at 295-297.

time, PG&E disputes TURN's position to some extent, stating that for some areas identified as needing capacity expansion, these are not viable options. In addition, PG&E states that it continues to see load growth in a number of areas not currently affected by policies restricting gas usage.[663]

In Section 1.5 above, PG&E advocates forecasts based on 2020 recorded data and 2021 and 2022 forecasted data. But for this forecast it uses data in 2021 for four new, uncertain projects in their early planning stages estimated between $30 million and $55 million. Yet, PG&E's forecast is based on 50% of three-year average resulting in a forecast of $8.6 million. The Commission finds this methodology to be irreconcilable. Instead, the Commission adopts a forecast based on the more recent average of the data as recommended by TURN from 2018-2020 of $6.028 million for 2023 for MAT 73A.

3.11. Gas Technology

PG&E states that the purpose of the R&D and Deployment Program is to detect, develop, test, and introduce new methods and technologies into PG&E's Gas Distribution And Transmission operations to improve gas safety, reliability, and efficiency. The R&D and Deployment team has defined seven priorities that address the major threats, as identified in the Gas Operations' Risk Register and support mitigation measures: (1) extending the safe operational lifetime of our pipelines; (2) understanding the condition of PG&E's assets; (3) developing proactive, as opposed to reactive, operations; (4) reinventing leak management; (5) eliminating dig ins; (6) improving construction methods; and (7) decarbonizing the gas system. While these priorities help guide R&D and Deployment, efforts undertaken on a year-to-year basis vary based on risks to PG&E's gas organization

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[663] PG&E Reply Brief at 297-298.

and collective needs of the collaborations and consortia to which PG&E contributes.[664] For Gas R&D and Development, PG&E's forecast for 2023 is $11.497 million ($5.850 million Gas Distribution and $5.647 million Gas Transmission). This amount is more than twice the 2020 recorded amount of $5.339 million. The largest driver of this increase is in the category of Contributions to Collaborations and Consortiums – Other, which PG&E seeks to increase from $1.777 million in 2020 to $5.863 million in the 2023.[665]

TURN recommends reducing the Gas R&D and Deployment Program forecast for Gas Transmission by $2.002 million to $3.648 million and the forecast for Gas Distribution by $2.084 million to $3.766 million.[666] TURN bases its forecast on the last recorded year level of $1.777 million for Contributions to Collaborations and Consortiums – Other because PG&E provided no supporting documentation or calculations to support the requested increase.[667]
Cal Advocates recommends a similar reduction because PG&E's request is inadequately supported.[668]

The Commission agrees with both intervenors that the 2020 costs are the last recorded year and the most known and measurable basis for a forecast and adopts a forecast of $7.414 million for PG&E's 2023 Gas R&D and Deployment Program. However, PG&E shall not record any Gas R&D and Deployment

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664 PG&E Opening Brief at 334.

665 TURN Opening Brief at 328.

666 TURN Opening Brief at 328-329.

667 TURN Opening Brief at 328.

668 Cal Advocates Opening Brief at 113-114.

program expenses in a one-way balancing account until an annual Tier 3 Advice Letter outlining its Gas RD&D budget plan is approved.[669]

Consistent with prior Commission decisions and resolutions approving other gas R&D and Development Programs,[670] PG&E shall submit an annual R&D and Development research plan for Commission approval. In Resolution G-3592, the Commission approved a proposed budget for the California Energy Commission (CEC) gas R&D program for fiscal year 2022-2023 of $960,000. This amount will fund a comprehensive evaluation of the CEC's Gas R&D program to be implemented by Energy Division, including developing a scope of work, issuing a competitive request for proposal, and hiring and managing the contractor.[671] This will ensure optimal research investment to promote innovation, ratepayer benefits, and coordination with other gas RD&D programs. To ensure accountability of PG&E's Gas R&D and Development portfolio, PG&E shall submit its annual research plan via an initial Tier 3 Advice Letter filed by June 1, 2024 following guidance based on D.19-09-051, Resolution G-3586, and Resolution G-3592 as follows:

(1) The annual research plan should detail budgets broken down by research sub-program area and explain how the projects improve reliability, safety, equity, affordability, and environmental benefits, and incorporates input from key stakeholders, such as the Disadvantaged Communities Advisory Group.[672]

(2) The annual research plan should include a proposed benefits analysis framework, created in consultation with

[669] D.19-09-051 (SoCalGas Test Year 2019 GRC) at 379.

[670] D.19-09-051 (SoCalGas Test Year 2019 GRC).

[671] CPUC Resolution G-3592, OP 3.

[672] D.19-09-051 at 379.

Energy Division staff. This framework should provide sufficient quantitative estimates of potential safety, reliability, operational efficiency, improved affordability, environmental-related benefits, benefits to underserved communities, and numeric targets or a specified numeric range of potential benefits for projects.[673]

(3) PG&E should cap its administrative costs for Gas RD&D at 10%.[674] Using Staff's recommended decrease in funding, this would cap PG&E's administrative budget at $741,442. PG&E's annual research plan should provide detail about administrative costs and require PG&E to allocate these cost categories to its administrative budget as outlined below:[675]

Program Administrative Cost Budget Item	**Calendar Year ($)**
Investment Plan Development	
Project Planning and Initiation	
Project Oversight and Governance	
Stakeholder Communication, Engagement, and Outreach	
Regulatory Support Compliance	
Internal Management Coordination	
Program and Process Coordination and Improvement	
Administrative Activities	
Supervision and Personnel	
Training and Development	
Total	

(4) In its annual research plan, PG&E should explain how its proposals for low carbon research projects (rather than

[673] CPUC Resolution G-3586, OP 5.

[674] D.21-11-028.

[675] Resolution G-3586, OP 4.

zero/no carbon projects) support the State's aggressive zero-carbon goals.[676]

(5) The annual research plan should include information on funds encumbered, spent, and unspent. The plan should also outline co-funding and collaborative partners and explain how P&GE engages with diverse academic populations. Further, PG&E should describe how its research plan will benefit underserved communities.[677]

(6) PG&E shall hold an annual workshop prior to submitting its Tier 3 Advice Letter Annual Gas RD&D Investment Plan and shall consult with Energy Division to develop the workshop agenda. The annual workshop shall be held at least 90 days before submitting its annual Gas RD&D research plan to the CPUC to allow sufficient time to incorporate stakeholder feedback. At these workshops, PG&E shall present the results of the previous year's RD&D program and obtain input regarding its proposed spending for the following calendar year. The workshop shall follow the guidance of D.19-09-051 Ordering Paragraph 30.[678]

(7) Prior to the workshop, PG&E should submit its RD&D annual report to Energy Division staff describing prior years' RD&D program including a summary of ongoing and completed projects; funds expended, funding recipients, and leveraged funding; and an explanation of the process used for selecting RD&D project areas as well as the structure of PG&E's RD&D portfolio.

(8) PG&E shall provide Energy Division staff with the workshop presentation materials as well as documentation on stakeholders consulted in the

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[676] Resolution G-3586 at 20-21 describes the Commission's preference toward zero-emissions projects.

[677] Resolution G-3586.

[678] D.19-09-051 at OP 30.

development of RD&D projects, both at least one week before the workshop.

(9) PG&E shall engage relevant stakeholders to encourage their attendance at the workshop, such as the California Energy Commission, the Disadvantaged Communities Advisory Group, the U.S. Department of Energy, and other organizations engaged in gas research and development.

(10) PG&E's research plan should allocate approximately $296,400 to an evaluation or audit.

(11) PG&E's research plan may separately allocate and track funds for gas research development and deployment in one database that tracks all ratepayer-funded R&D and Development projects across these industries.

3.12. Other Gas Operations Support

PG&E states that general support expenses for both Gas Distribution and GT&S related to various programs includes the Engineer Rotation Development Program (ERDP); gas consulting contracts; gas operations data management; the Gas Asset Strategy's Alternative Energy Program, and CEMA straight time labor. For the distribution portion of CEMA straight time labor, MAT AB#, PG&E's 2023 forecast is $16.4 million. For the CEMA straight time labor GT&S portion of MAT AB#, PG&E's 2023 forecast is $18.0 million, including $1.3 million for the Alternative Energy Program.[679] The CEMA straight time labor expense is discussed below in Section 3.12.1.

The Alternative Energy Program provides an incentive for customers to replace their gas equipment and appliances with electric where such conversion avoids the need for more costly upgrades or replacement of current gas assets and aligns with PG&E's efforts to reduce its overall gas footprint while reducing

[679] PG&E Opening Brief at 336.

risk in the system. The Alternative Energy Program has been focused on high pressure regulator conversions, but PG&E also leverages conversions "when there is a complex execution issue such as compromised infrastructure or challenging areas (railroad tracks, rivers, canal, shallow pipe, remediation site, Cal Trans right-of-way, newly paved, moratorium, erosion)."[680]

TURN recommends that PG&E be authorized twice its requested amount, or $2.6 million annually, to pursue the Alternative Energy Program in 2023 and the years following, subject to reporting requirements that would help inform the state's future efforts at coordinating customer electrification with opportunities to reduce gas system investments."[681] While still small in scope, the Alternative Energy Program is a promising program that could help illuminate opportunities and barriers to effectively coordinating customer electrification with gas system planning.

PG&E agrees with TURN's recommendation to increase funding for the Alternative Energy Program. But PG&E does not agree the detailed reporting recommended by TURN[682] is necessary or narrowly tailored to inform future gas system planning efforts and maximize the benefits to ratepayers from funding customer electrification. Instead, PG&E urges the Commission reject TURN's detailed reporting proposal and instead direct Commission staff to host a workshop with parties to develop the appropriate topics for reporting and timing for implementation.

The Commission observes that gas system planning efforts and those to fund customer electrification should also be coordinated with related programs

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680 TURN Opening Brief at 330.

681 PG&E Opening Brief at 337.

682 TURN Opening Brief at 330-332.

and proceedings, including the Long-term Gas Planning and Zonal Electrification proceedings. Related programs that fund gas capital investments that may be avoided through electrification include the Reliability Service Replacement Program (MAT 50B), the High-Pressure Regulator Program (MWC 2K), the gas Advanced Metering Infrastructure Module Replacement Program, the New Business Program, and the Work At The Request Of Others Program. Accordingly, the Commission adopts a forecast of $2.6 million for the Alternative Energy Program. These funds shall be tracked in a two-way balancing account to track additional funding diverted from the gas capital investment programs above. In addition, the Commission directs PG&E to host a meeting in coordination with the Commission Energy Division to develop the topics for reporting and timing for implementation consistent with this decision. Notice of this meeting should be provided on the service list for Long-Term Gas Planning proceeding, R.20-01-007, and for Building Decarbonization proceeding, R.19-01-011.

3.12.1. StanPac Transmission Pipeline (Expense MAT 34A and Capital MAT 44A)

PG&E states that it owns, operates, and maintains the StanPac Transmission Pipeline that runs from Rio Vista to Richmond.[683] PG&E tracks work for StanPac Transmission Pipeline in MAT 34A for expense and MAT 44A for capital. The StanPac expense MAT tracks any gas expense project on a StanPac line. PG&E's 2023 expense forecast is based on a three-year average (2018-2020), adjusted to remove one-time historical projects, and includes project-specific additions related to programs in the Transmission Pipe Asset Family. The StanPac capital MAT covers any gas capital project on a StanPac line.

[683] One-seventh of this pipeline is owned by the Chevron Corporation.

PG&E's 2023-2026 capital forecast is based on a three-year average (2018-2020), adjusted to remove one-time historical projects, and includes project-specific additions related to programs in the Transmission Pipe Asset Family.[684]

TURN recommends adjustments to Transmission Pipe Asset Family programs (Traditional ILI, ICDA, and Strength Testing) that impact expense and capital costs for the StanPac Transmission Pipeline.

Consistent with the TURN forecasts adopted for these programs above, the Commission adopts TURN's proposed $.507 million reduction to PG&E forecast for StanPac expenses (MAT 34A) and $2.505 million in 2023.[685] For capital expenditures (MAT 44A), the Commission adopts forecasts of $2.887 million in 2023, $2.880 million in 2024, $15.245 million in 2025, and $15.736 million in 2026 based on TURN's proposed adjustments.[686]

3.12.2. CEMA Straight Time Labor Expense (MAT AB#) and Capital Expenditure (MAT 21#)

PG&E proposes a new two-way balancing account, which PG&E refers to as the Catastrophic Event Straight-Time Labor Balancing Account (CESTLBA), to recover straight time labor costs associated with its repair and restoration activities for Catastrophic Event Memorandum Account (CEMA)-eligible events.

PG&E's CEMA straight time labor request for Gas Operations is forecast in MAT 21# for capital and MAT AB# for expense.[687] This program and party positions are discussed in detail in Section 4.6.2.

[684] PG&E Opening Brief at 339.

[685] TURN's proposed reduction is provided in PG&E Ex-16-E (Rebuttal) at 13-4T (Table 13-2). PG&E's final forecast of $3.012 million is provided in PG&E Ex-03-ES at iii.

[686] PG&E Ex-16 (Rebuttal) at 13-6, Table 13-4; PG&E Ex-03-ES at v; TURN proposed the following capital adjustments: +$.077 million for 2023, -$3.282 million for 2025, and -$3.366 million for 2026. TURN Opening Brief at 986.

[687] PG&E Opening Brief at 332.

For MAT AB#, PG&E's CEMA expense forecast is $2.9 million in 2023.[688] For MAT 21#, PG&E's capital expenditure forecast is $2.1 million in 2023, $2.1 million in 2024, $2.2 million in 2025, and $2.3 million in 2026.[689]

As discussed in Section 4.6, the Commission denies PG&E's request to establish a CEMA straight-time labor balancing account. Accordingly, PG&E's request to recover related expenses and capital expenditures is denied.

3.13. New Business and Work at the Request of Others

PG&E's states that its New Business work consists of connecting new customers to PG&E's Gas Transmission or Gas Distribution systems, and Work At The Request Of Others consists of relocating PG&E's existing Gas Transmission or Gas Distribution facilities at the request of governmental agencies, customers, and other third parties. This work includes eight expense MATs related to Work at the Request of Others and 17 capital MATs.[690] The disputed forecasts are discussed below.

3.13.1. Gas Transmission Work at the Request of Others (Expense MAT JTA)

PG&E states that its Gas Transmission Work At the Request Of Others (WRO) program encompasses work required by tariff, third-party requests, and franchise compliance. This work includes Gas Transmission non-plant relocations and alterations of gas facilities requested by others. Typical projects include valve frame and cover alterations for street widening projects, lowering transmission facilities to avoid a conflict with agency roadwork, adding mechanical protection such as a concrete cap over a pipeline crossing a highway,

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688 TURN Opening Brief at 327.

689 PG&E Opening Brief at 332.

690 PG&E Opening Brief at 340-341.

road, street, or other facility, and accommodating a project without requiring the re-location of the pipeline. This work is generally required by City, County, State, or other jurisdictional agencies.

For work tracked in MAT JTA, PG&E requests a 2023 expense forecast of $1.129 million based on an escalated five-year average of recorded costs from 2015 to 2019.[691] This represents a $0.9 million increase over recorded 2020 expenses, which PG&E attributes to a low amount of spending in 2020 compared to historical averages.[692] PG&E explains that its forecast was developed using a five-year historic annual average from 2015-2019. Each year was escalated to the rate case base year and then an average was developed based on net costs. A five-year average was chosen to accommodate the changes that occur within the WRO Program. Agencies and developers consistently adjust their timelines based on funding and readiness issues. According to PG&E, utilizing five-year average accounts for some of the variations that can occur with respect to WRO projects.[693]

Cal Advocates recommends a reduction in the MAT JTA forecast of about 50% to $0.51 million on the basis that PG&E failed to prove that its methodology accurately forecasts its 2023 MAT JTA expenses.[694] Cal Advocates contends that 2020 expenses were not significantly lower than previous years. From 2016-2021, PG&E's expenses for MAT JTA averaged $0.37 million per year. Cal Advocates also claims that PG&E picked a period with the highest costs, escalated those costs even more, and then developed an average to support its forecast.

[691] PG&E Opening Brief at 342.

[692] Cal Advocates Opening Brief at 114.

[693] Cal Advocates Opening Brief at 133.

[694] Cal Advocates Opening Brief at 114-115.

According to PG&E's historic recorded expenses, 2020 was not an anomalous year. In fact, 2020 recorded expenses of $288,000 were higher than 2019 recorded expenses of $173,000 and 2017 recorded expenses of $83,000. To calculate its six-year average of historic costs, Cal Advocates eliminated the "high-cost year" of 2015 and used recent 2020 and 2021 data. This yielded average expenses of $0.37 million per year for MAT JTA.[695]

In response, PG&E states that Cal Advocates' six-year 2016-2021 average of yearly expenses is not representative because it selectively omits the high spending year of 2015 but includes the very low 2020 spending year that was impacted by COVID-19. PG&E contends that the five-year average from 2015 to 2019 is the most accurate representation of the recorded expense variations that can occur within this program. In addition, PG&E claims that Cal Advocates use of 2021 data is improper because 2021 recorded expenses for 2021 were not available to PG&E when determining its 2023 forecast prior to filing on June 30, 2021.

This dispute hinges on whether the average of recorded costs for MAT JTA for the five years from 2015-2019 or the average from 2016 to 2021 better represents the Gas Transmission expense forecast for work at the request of others. PG&E argues for using the earlier average and excluding 2020 recorded expenses because MAT JTA recorded expenses in 2020 were 70% below the 2015-2019 average of $957,000 due to the impacts of Covid-19.[696] Cal Advocates argues that 2020 recorded expenses were not anomalous because the amount of $288,000 was higher than 2019 recorded expenses of $173,000 and 2017 recorded

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[695] Cal Advocates Opening Brief at 134.

[696] PG&E Opening Brief at 343.

expenses of $83,000. In addition, Cal Advocates argues for excluding the high-cost recorded in 2015.

The Commission finds that the costs tracked in MAT JTA recorded in 2015 were arguably far more anomalous because they were $4.2 million,[697] which is over 400% above the 2015-2019 average of $957,000. Although Covid-19 started to have an impact in 2020, whatever impact it may have had on work at the request of others may have continued. Nevertheless, the Commission does not find the 2020 recorded expenses to be so anomalous that they should be excluded from the average used for forecasting. The impact of Covid-19 also provides a reason for including 2021 data in the average. Furthermore, the Commission finds it reasonable to use the 2016-2021 average because it provides additional and more recent data that would better represent conditions from 2023-2026. Accordingly, the Commission adopts a 2023 expense forecast of $0.510 million for Work At The Request Of Others, which is tracked in MAT JTA, based on the more recent and representative average.

3.13.2. Gas Distribution New Business Program (Capital MWC 29)

PG&E originally proposed a forecast of $126.2 million in capital expenditures in MWC 29 but recommended a reduced forecast of $85.4 million in its Opening Brief to reflect the anticipated impact of the Commission's recent decision that eliminated gas line extension allowances as of July 1, 2023.[698] TURN's Opening Brief proposes a reduction of approximately $16 million to make adjustments to protect ratepayers from overpaying for gas new connections in light of D.22-09- 026. TURN proposed either a 50% forecast

[697] PG&E Ex-03 at WP 14-7 (Table 14).

[698] D.22-09-026.

reduction plus a new one-way balancing account or requiring PG&E to update its MWC 29 forecast by Tier 2 Advice Letter on August 1, 2023, to reflect the applications submitted before the July 1 deadline.

Since the filing of Opening Briefs, TURN and PG&E reached a mutually agreeable resolution of the forecast for work tracked in MWC 29 as reflected in the *Stipulation on Gas Distribution Capital New Business Program (MWC 29)*, attached to TURN's Reply Brief as Appendix A. Based on this stipulation, TURN and PG&E stipulate to resolve all MWC 29 forecast issues under the following terms:

1. PG&E's TY 2023 forecast for MWC 29 will be $72 million. This forecast will not be subject to the standard attrition adjustment mechanism authorized by the Commission but will stay the same over the four-year 2023-2026 rate case cycle, i.e., $72 million in each year.
2. PG&E will establish a new one-way balancing account to track MWC 29 new business connection costs. The account will be referred to as the Gas Distribution New Business Balancing Account (GDNBBA).
3. The new one-way balancing account will be trued up at the end of the 4- year 2023-2026 rate case cycle, with any underspending returned to ratepayers. Any spending above the forecast will be reviewed as part of PG&E's 2027 general rate case for inclusion in rate base.
4. Funding for allowances associated with interconnection applications after July 1, 2023 will be separate from the MWC 29 funding adopted in the general rate case pursuant to this Stipulation and addressed through the annual application process established in D.22-09-026, Ordering Paragraphs 2 and 3.
5. Although this Stipulation resolves all issues related to the 2023 rate case forecast for MWC 29, nothing in this Stipulation shall be interpreted as a waiver of any Party's

position on the issues raised by TURN in testimony regarding the forecast of residential building permits.[699]

After reviewing the uncontested stipulation, the Commission finds that the stipulation, on its own merits, is reasonable in light of the whole record, consistent with the law, and in the public interest. It is clear from the record and from the stipulation that PG&E and TURN had the necessary understanding of the issues and facts and the capacity to engage in the stipulation process. Therefore, the Commission finds it is reasonable to adopt the stipulation. Accordingly, the Commission adopts a forecast for MWC 29 for 2023 of $72 million that will remain constant over the four-year 2023-2026 rate case cycle. The Commission also directs PG&E to establish the GDNBBA, a one-way balancing account that will track MWC 29 new business connection costs which will be trued up at the end of the four-year 2023-2026 rate case cycle, with any underspending returned to ratepayers.

3.13.3. Gas Transmission New Business Program (Capital MAT 26A)

PG&E states that the Gas Transmission New Business program consists of projects that require either significant pressure or new load along with other major projects. PG&E's forecast for Gas Transmission New Business program is $7.923 million in 2023.[700] PG&E used a five-year historical average (2015 through 2019) of escalated capital expenditures to determine the forecast for the 2023-2026 rate case period. In addition, PG&E added $5.774 million for anticipated major conversion projects. The additional amount was based on PG&E's Large Gas Solutions Program (LGSP) that presents solutions to large customers to switch

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[699] TURN Reply Brief at 79-80.

[700] PG&E Opening Brief at 353.

from alternative higher GHG fuels to natural gas, fueling back up generation with natural gas versus diesel, and converting heavy duty fleets to CNG and constructing CNG stations.[701]

TURN recommends reducing the $2.054 million base forecast for MWC 26 by 50% to $1.027 million and subject it to a one-way balancing account, and to remove the $5.774 million forecast for the LGSP entirely, to be considered in the annual applications allowed by D.22-09-026.[702] TURN contends that D.22-09-026 will impact these transmission level costs in the same way that it impacts the distribution level costs recorded in MWC 29 because both involve the costs of connecting new customers to the system, albeit customers of different sizes. TURN also contends that the customers targeted for the LGSP are exactly the type of large customers currently using non-gaseous fuels that are likely to be reflected in the annual applications for special case line extension allowances allowed by D.22-09-026. Finally, TURN states that PG&E continues to include $5.774 million in its MWC 26 forecast for the LGSP even though PG&E excludes projects that might qualify for the new annual application process from its revised forecast for MWC 29 "[s]ince there is currently no way of forecasting these projects." Instead, TURN recommends removing PG&E's LGSP costs from the forecast, which PG&E can instead pursue through the annual application process created by D.22-09-026, where the Commission can address the appropriateness of providing line extension allowances, as well as cost recovery.[703]

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[701] PG&E Opening Brief at 352-353.

[702] TURN Reply Brief at 83.

[703] TURN Opening Brief at 345-348.

In response, PG&E states that TURN's recommendation to reduce the forecast by 50% to reflect the impact of the allowance decision is unreasonable given the lag in payments for existing projects, and the real possibility of a "rush" of new applications ahead of the July 2023 deadline. The forecast related to PG&E's historic spending of $2.1 million is expected to be needed to cover projects that have already been initiated and for new applications that PG&E anticipates will be submitted before July 2023. As PG&E explained in its Opening Brief, due to the lag in contracting and construction that follows submission of an allowance application, the allowances for residential new business projects are expected to be paid in 2023, 2024 and 2025. Gas transmission interconnection projects are potentially larger and more complex than residential interconnections and the lag between applying for allowances and ultimate payment of the allowances is expected to be even longer. Thus, notwithstanding the gas allowance decision, PG&E expects to incur costs for gas transmission project allowances related to applications received before July 2023 throughout the 2023-2026 period. PG&E argues an adjustment to its forecast for MAT 26A is therefore not warranted since it expects to pay allowances over the entire 2023-2026 rate case period. Second, PG&E argues $5.8 million is needed for its Large Gas Solutions Program because this program is creating a higher level of new business activity than in past rate case periods. In the past, PG&E's gas transmission new business service projects would occur only as customers requested them. Today, PG&E is proactively identifying opportunities that align with California's climate goals and is reaching out to customers utilizing fuels such as coal, propane, and diesel to convert them to natural gas.[704]

[704] PG&E Reply Brief at 309-312.

The Commission finds PG&E's criticism of TURN's recommendation convincing. However, given the uncertainty in this forecast, the Commission also adopts the unopposed proposal to establish a one-way balancing account to reconcile revenue associated with this forecast at the end of the rate case cycle. This approach protects ratepayers against the possibility that the payment of gas allowances will be lower than forecast. Accordingly, the Commission adopts a forecast for work at the request of others tracked in MAT 26A for 2023 of $7.83 million.

3.13.4. Gas Transmission Work At The Request Of Others Program (Capital MAT 83A)

PG&E states that its Gas Transmission Work At The Request Of Others Capital Program covers transmission pipeline or related facility removals and relocations performed by PG&E at the request of third parties. These projects are typically requested by governmental agencies, such as Cal Trans, cities, counties, regional transportation agencies, and private developers. These projects are primarily driven by public improvement work, under which PG&E's obligation to relocate its facilities is subject to the terms of a franchise agreement, master agreement, or eminent domain.

PG&E's original forecast for the Gas Transmission WRO Capital Program was $20.9 million in the 2023 test year.[705] A five-year historical average (2015 through 2019) of actual net capital expenditures for this program was used to determine the forecast for the rate case period. Based on information available at the time, an additional cost of $5.5 million for the Department of Water Resources Delta Conveyance Project was also included in the forecast. Following

[705] PG&E Opening Brief at 354-355.

removal of $5.5 million from the 2023 forecast for MAT 83A, the reduced forecast that PG&E is seeking is $16.0 million.

The Commission finds the removal of $5.5 million for the Delta Conveyance Project due to its unlikely performance during this rate case period to be reasonable. Accordingly, the Commission adopts the reduced forecast for MAT 83A of $16 million in 2023 capital expenditures.[706]

3.14. Ratemaking

This Section addresses changes to cost recovery accounts related to PG&E's Gas Operations that have not already been addressed above. No parties contest PG&E's request to close 15 accounts. The details regarding these balancing and memorandum accounts and citations to PG&E's testimony are provided in Appendix B of PG&E's Opening Brief. The Commission addresses these accounts below.

3.14.1. Internal Corrosion Balancing Account

The Commission's 2019 GT&S decision established the one-way balancing account, referred to as the Internal Corrosion Balancing Account (ICBA), for capital internal corrosion expenditures work recorded in MAT 3K1. The Commission's rationale for establishing the ICBA was that PG&E's 2019 GT&S rate case application did not explain with adequate detail its methodology for calculating its capital expenditure forecast.[707]

PG&E recommends that the Commission discontinue the ICBA because it has addressed the Commission's concern underlying establishment of the ICBA. PG&E explains that, in its exhibits and workpapers submitted as part of this rate case, PG&E has provided the 2023-2026 capital cost forecast for Capital Internal

[706] PG&E Reply Brief at 313-314.

[707] D.19-09-025 at 329, OP 54.

Corrosion, which is based on actual pipe replacement data that is utilized across multiple chapters of its Application.[708] In addition, PG&E asserts that Cal Advocates did not take contest PG&E's 2023 forecasting basis or approach.[709]

Cal Advocates disagrees and recommends that the Commission continue with the ICBA. In support of its recommendation, Cal Advocates asserts that PG&E has performed below the level adopted by the Commission for the years 2019-November 2021. For example, the Commission authorized $13.012 million in 2019 but PG&E only recorded $135.61 million. Similarly, the Commission authorized $13.003 million in 2020, and PG&E only recorded $3.408 million. Cal Advocates further asserts that it is not convinced PG&E will replace or remove pipelines at the level proposed for the next GRC cycle.[710] As a result, Cal Advocates contends that PG&E will lose an incentive to keep costs low and protect ratepayers if the Commission discontinues the ICBA.[711]

In response, PG&E acknowledges that recorded expenditures for Capital Internal Corrosion Mitigation MAT 3K1 for the period 2019-November 2021 were below the adopted values. However, PG&E states that it anticipates exceeding the number of pipeline drip replacements forecast in the 2019 GT&S. In addition, PG&E claims that Cal Advocates argument is based on recorded spending and does not consider the number of pipeline drips that have been removed or replaced.[712]

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[708] PG&E Opening Brief at 356.

[709] PG&E Reply Brief at 321-322.

[710] PG&E Opening Brief at 357.

[711] Cal Advocates Opening Brief at 125-126.

[712] PG&E Reply Brief at 321-322.

The Commission finds that persuasive evidence exists that the Commission that the ICBA is still appropriate. Accordingly, the Commission continues to direct PG&E to use the ICBA.

3.14.2. New Environmental Regulations Balancing Account

PG&E explains that the New Environmental Regulations Balancing Account (NERBA) is used to track the difference between actual and adopted costs related to 26 best-practice activities associated with minimizing methane emissions as adopted by the Commission in the Natural Gas Leak Abatement Order Instituting Rulemaking (R.15-01-008). This account was retained through 2022 for the purpose of tracking costs associated with below ground Grade 3 leak repairs. The Commission authorized NERBA in response to arguments regarding uncertainties around the implementation of new laws and regulations. At the time, PG&E asserted there are potentially significant differences between PG&E's 2017 GRC leak management forecast and new requirements.

PG&E requests the continuation of NERBA through the 2023 rate case period for the following reasons: (1) Commission Resolution G-3538 created uncertainty as to what level of below ground grade 3 repairs the Commission would deem to be cost-effective; (2) the biennial leak abatement compliance plan process means that the uncertainty of the appropriate level of below grade 3 repairs is likely to continue; and (3) continuing NERBA will not impact PG&E's efficiency and cost-effectiveness of doing below grade 3 leak repairs since PG&E's execution of leak repair is uniform for all leak repairs and does not differentiate between NERBA eligible repairs and other repairs. Based on these reasons, PG&E maintains that continuing NERBA would protect ratepayers against the continued uncertainty and potential fluctuation in the number and costs of such repairs.[713]

Cal Advocates opposes PG&E's request to continue the NERBA. Cal Advocates acknowledges that the cost-effectiveness of the forecasted repairs could change, but that should not make this forecast eligible for a two-way balancing account or warrant the continuation of NERBA as a two-way balancing account. Otherwise, ratepayers would be responsible for repairs and costs without check and without a cap to incentivize PG&E to be efficient and cost effective.[714]

The Commission finds that the high level of uncertainty regarding the number and cost of repairs reasonably supports continuation of NERBA during this rate case period (2023-2026).

3.15. Gas Operations Uncontested Expense and Capital

Unless otherwise provided, regarding the uncontested forecasts for 2023 expense and 2021, 2022, and 2023 capital expenditures for the Gas Operations and Maintenance, the Commission finds those amounts to be reasonable. The uncontested expense and capital expenditure forecasts are set forth in Appendix A of PG&E's Opening Brief at A-17 and A-25.[715]

4. Electric Distribution

4.1. Overview

PG&E's Electric Distribution forecast for expense and capital expenditures is set forth in PG&E Ex-04 and related documents. The forecast presented for

[713] PG&E Opening Brief at 357-358; PG&E Reply Brief at 322-324.

[714] Cal Advocates Reply Brief at 449-451.

[715] PG&E Opening Brief at 261.

Electric Distribution represents a significant portion of PG&E's total forecast in this proceeding at approximately $2.6 billion for 2023 expense and $4.7 billion for 2023 capital expenditure forecasts.[716]

PG&E's proposed wildfire risk reduction activities are a major driver in the cost forecast. As a result, its risk reduction analysis and general affordability factors are major themes in PG&E's forecasts for Electric Distribution line of business. Affordability and safety via a combination of risk reduction activities are the core of the of the Commission's mission, as stated by the Commission in 2015 and repeated in 2018, "… the ultimate balance the Commission must strike is between safety and reasonable rate levels, or as expressed in that same decision, 'between affordability and risk reductions.'"[717]

PG&E's electric distribution system is essential in the provision of a basic public service, electric service but carries with it inherent risk. PG&E's approach to provision of electric service must mitigate the grave risks posed by wildfire to Californians' safety, health, and property. Reducing the risk of harm is necessary and can be costly. This decision must determine whether PG&E has proven, by the preponderance of evidence, that its cost forecasts related to mitigating risk and other operational needs related to Electric Distribution are reasonable in light of the broader context of this proceeding.[718]

As part of its Plan of Reorganization, PG&E made a series of commitments regarding governance, operations, and financial structure, all designed to

[716] PG&E Reply Brief, Appendix A at A-2 to A-3. These figures reflect September 6, 2022 escalation adjustment in PG&E Ex-33.

[717] D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-Map) Settlement Agreement with Modifications (December 13, 2018) at 6, fn. 8 citing to D.15-11-021.

[718] PG&E Ex-04 at 1-5.

prioritize safety. Some of the commitments impacting Electric Distribution are as follows:[719]

- Introducing a six-step Enhanced Oversight and Enforcement Process to ensure that PG&E meets safety and operational commitments, and promptly corrects any issues that may arise;
- Achieving PAS55 and ISO55001 certifications; and
- Setting financial targets for Electric Distribution forecasts to help position PG&E to deliver cost-effective service to customers while actively managing costs within budgets to improve long-term costs and financing plans.

PG&E's Electric Distribution revenue requirement forecast for 2023-2026 proposes significant cost increases over the recent years at $8.8 billion in 2023 (approximately +56% over 2022);[720] $9.3 billion in 2024 (+5.9% over 2023); $10 billion in 2025 (+8.7% over 2024); and $11 billion in 2026 (+8.6% over 2025).[721] The revenue requirement forecasts reflect PG&E's proposals for both capital expenditures (and the resulting rate base) and expenses.

During the rate case period, the capital expenditures forecasts for Electric Distribution, including the September 6, 2022 adjustments to escalation rates in PG&E Ex-33, are $3.57 billion in 2021, $4.21 billion in 2022, $4.73 billion in 2023, $5.28 billion in 2024, $5.59 billion in 2025, and $6.15 billion in 2026.[722] PG&E's

[719] PG&E Ex-04 at 1-6.

[720] PG&E Ex-33 at 4-AtchA-3, Table 2; PG&E Ex-10 at 1-2, Table 1-1.

[721] PG&E Ex-64 (JCE) at 4-52. PG&E's Reply Brief included decreases in its cost forecast for System Hardening but PG&E did not provide updated revenue requirement figures for Electric Distribution.

[722] PG&E Reply Brief at 332; PG&E Opening Brief at Appendix H-2, PG&E Ex-04, PG&E Ex-64 (JCE) at Ch. 3, Tables 3A-1 and 3B-1.

2020 recorded adjusted capital expenditure is $3.1 billion.[723] The total 2023-2026 forecast for capital expenditures for Electric Distribution is $21.8 billion.[724] PG&E states that 86% of its 2023 capital expenditure forecast for Electric Distribution is contested in this proceeding.[725]

PG&E's 2023 expense forecast for Electric Distribution is $2.6 billion, which includes an increase in the escalation rates submitted by PG&E on September 6, 2022.[726] PG&E's 2020 recorded adjusted Electric Distribution expense is $2.2 billion.[727]

PG&E's recorded 2022 and estimates for 2023-2026 for the rate base associated with Electric Distribution are: 2022 is $22.699 billion; 2023 is $25.6 billion; 2024 is $28.9 billion; 2025 is $32.7 billion; 2026 is $36.8 billion.[728] PG&E's recorded 2020 rate base for Electric Distribution is $18.880 billion.

PG&E identifies the following as key developments in Electric Distribution since its last GRC for test year 2020: (1) focusing on wildfire risk; (2) advancing risk assessment and risk management; (3) coronavirus pandemic; and (4) emergence from bankruptcy; and (5) pursuing operational excellence.[729] Then PG&E points to areas of focus within its forecast for Electric Distribution,

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[723] PG&E Ex-04 at 2-47.

[724] PG&E Reply Brief at 332. (Adding together 2023-2026 capital expenditures, which include PG&E Ex-33 September 6, 2022 Update Testimony.)

[725] PG&E Reply Brief at 332.

[726] PG&E Opening Brief at Appendix H-2, PG&E Ex-04 at Ch. 2, PG&E Ex-64 (JCE) at Ch. 3, Tables 3A-1 and 3B-1; PG&E Reply Brief at 331.

[727] PG&E Ex-04 at 2-5.

[728] PG&E Ex-10 at 15-2 (Table 15-1); PG&E Ex-11 at 3-13 (Table 3-4); PG&E Ex-64 (JCE) at 4-15 and 4-57. Note: PG&E's changes to its forecast in its December 9, 2022 Reply Brief may have resulted in modifications to these rate base figures. PG&E did not provide revised forecasts.

[729] PG&E Ex-04 at 1-2 to 1-6.

including (1) continued focus on wildfire risk mitigation work; (2) increasing customer focus by delivering on customer commitments; (3) supporting California's clean energy goals; (4) improving public and workforce safety; and (5) continued focus on operational excellence.

The Commission reviews PG&E's forecast for Electric Distribution below.

4.2. Wildfire Risk Mitigation Forecast

PG&E's 2023-2026 Wildfire Risk Mitigation expense and capital expenditure forecasts are set forth in PG&E Ex-04, Ch. 4.1 through Ch. 4.6 and summarized in the below tables. The tables are organized by the type of Wildfire Risk Mitigation project proposed by PG&E together with the cost forecasts for this rate case period.

Table 4-A:
Recorded and Forecast Wildfire Mitigation Costs 2020-2026 – Capital[730]
Thousands of Nominal Dollars

PG&E Ex-04	PG&E Ex-04 Chapter Name	2020 Recorded Adj.	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Total
Ch 4.1	Situational Awareness and Forecasting	$11,649	$9,451	$9,375	$4,601	$3,290	$3,341	$3,446	$45,153
Ch 4.2	PSPS Operations	2,397	3,084	3,237	262	269	277	284	$9,809
Ch 4.3	**System Hardening, Enhanced Automation and PSPS Impact Mitigations**	**584,417**	**520,005**	**950,167**	**1,343,699**	**1,440,758**	**1,711,884**	**2,249,074**	**$13,025,501**

[730] Regarding the first column, "PG&E Ex-04," the amounts for Ch. 4.1 and Ch. 4.2 refer to PG&E Ex-04 at 4-19 (Table 4-4). PG&E Ex-04, Ch. 4.3 amounts refer to the revised undergrounding forecast in PG&E December 9, 2022 Reply Brief, Table 4-1 at 328 (and Enhanced Automation and PSPS Impact Mitigation-System Hardening at PG&E Ex-04, Table 4.3-7 at 4-25). PG&E Ex-04, Ch. 4.4, Community Wildfire Safety Program PMO presents no capital expenditures. For the amount at Ch. 4.5, refer to PG&E Ex-04 at 4.5-23 (Table 4.5-3).

PG&E Ex-04	PG&E Ex-04 Chapter Name	2020 Recorded Adj.	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Total
Ch 4.5	IT for Wildfire Mitigations	$22,658	25,300	25,300	25,300	25,300	25,300	25,300	$174,458
Total		**$621,121**	**$557,840**	**$988,079**	**$1,373,862**	**$1,469,617**	**$1,740,802**	**$2,278,104**	**$9,029,425**

Table 4-B:
Recorded and Forecast Mitigation Costs 2020-2023 – Expense[731]
Thousands of Nominal Dollars

PG&E Ex-04	PG&E Ex-04 Chapter Name	2020 Recorded Adj.	2021 Forecast	2022 Forecast	2023 Forecast	Total
Ch 4.1	Situational Awareness and Forecasting	$34,022	$59,348	$54,559	$43,416	$191,345
Ch 4.2	PSPS Operations	141,178	127,920	119,254	115,266	503,618
Ch 4.3	**System Hardening, Enhanced Automation and PSPS Impact Mitigations[732]**	**7,872**	**7,949**	**6,679**	**11,595**	**34,095**
Ch 4.4	CWSP Program Management Office	34,263	27,801	14,994	13,460	90,519
Ch 4.5	IT for Wildfire Mitigations[733]	21,358	35,700	35,700	35,700	128,458
Ch 4.6	Enhanced Powerline Safety Settings	-	$18,203	$148,921	$151,129	$318,254
Total		$238,693	$276,921	$380,017	$370,566	$1,266,289

Within Wildfire Risk Mitigation, PG&E forecasts the majority of 2023-2026 capital expenditures for System Hardening (PG&E's undergrounding, covered conductor proposals, and other lesser costs, approximately $6.4 billion ($5.9 billion for capital for undergrounding and $517 million capital for covered conductor), and a 2023 expense forecast of approximately $11.595 million.[734]

[731] PG&E Ex-04 at 4-19 (Table 4-3) and at 4-29 (Table 4-7).

[732] The costs provided by PG&E with System Hardening (i.e., undergrounding and covered conductor) for the wildfire mitigation measure also include Enhanced Automation and PSPS Impact Mitigation, which represent a small percentage of the total costs represented by System Hardening, and are addressed by the Commission at Section 4.4, herein.

[733] PG&E Ex-04 at 4.5-23 (Table 4.5-2).

[734] PG&E Reply Brief at 352. This reduction reflects PG&E's modified proposal to reflect 2,000 miles of undergrounding (not including 100 miles for Community Rebuild MAT 95), as opposed to PG&E's prior proposal of 3,358 miles (not including 100 miles for Community Rebuild MAT 95). A reduction of 1,358 miles. Undergrounding miles are tracked in MAT 08W.

4.3. Wildfire System Hardening

The term System Hardening refers to methods relied upon by PG&E to manage its infrastructure to reduce risks of ignitions. This section addresses PG&E's forecast for System Hardening as it pertains to the projected use of two specific mitigations, undergrounding assets and covered conductor. Covered conductor involves replacement of bare overhead primary conductor and associated framing with conductor insulated with abrasion-resistant polyethylene coatings. Covered conductor can reduce the likelihood of faults including line-to-line contacts, tree-branch contacts, and faults caused by animals.

PG&E's System Hardening forecast focuses on mitigating wildfire risk posed by distribution overhead assets in and near Tier 2 and 3 HFTDs in its service territory. PG&E states that System Hardening targets high wildfire risk miles and applies various mitigation activities, including: (1) line removal, (2) conversion of distribution lines from overhead to underground, (3) application of Remote Grid alternatives, (4) mitigation of exposure through relocation of overhead facilities, and (5) in-place overhead system hardening.[735]

Undergrounding, and to a much lesser degree covered conductor, make up a significant portion of the System Hardening forecasts. The Commission first addresses the reasonableness of those requested costs below, together with the arguments by parties challenging PG&E's cost forecasts.[736] Other components of PG&E's System Hardening forecast, which includes Enhanced Automation, PSPS

[735] PG&E Ex-04 at 4.3-26.

[736] PG&E's undergrounding pertains costs forecasted in MAT 08W (and does not include Community Rebuild recorded in MAT 95F). The exact amount of these costs is at times difficult to establish.

Impact Mitigations, and other wildfire risk mitigation activities, are addressed in Section 4.4, herein.[737]

4.3.1. Modifications to System Hardening Forecast

PG&E modified its cost proposal for System Hardening (2023-2026) several times during this proceeding.[738] PG&E's initial System Hardening proposal of June 30, 2021 relied primarily on the use of covered conductor at 1,638 miles and 182 miles of undergrounding.[739] On February 25, 2022, PG&E "revis[ed] its System Hardening approach" and presented a plan that relied significantly more on undergrounding at 3,460 miles and much less on covered conductor at 320 miles.[740] PG&E presented its final System Hardening proposal on December 9, 2022, which reduced its proposal for undergrounding to 2,000 miles but did not change its covered conductor at 320 miles.[741]

The below tables present a detailed timeline of PG&E's modifications to the proposed undergrounding miles/forecast costs and covered conductor miles/forecast costs for 2023, 2024, 2025, and 2026 over the course of the proceeding.[742] The below tables (Tables 4-C and 4-D) include forecasted

[737] PG&E Ex-04, Ch. 4.3 at 4.3-1. Electric Distribution System Hardening Program, expulsion fuse replacement, enhanced automation for wildfire mitigation, and PSPS impact reduction initiatives.

[738] PG&E June 30, 2021 Application and prepared testimony; February 25, 2021 revised prepared testimony; December 9, 2022 Reply Brief.

[739] PG&E Ex-04 at 3-7.

[740] PG&E Ex-04 at Ch. 4.3 at 4.3-9 (Table 4.3-2.)

[741] The 2,000 miles forecast does not include Community Rebuild (Town of Paradise and surrounding areas) forecast of 100 miles. PG&E Ex-04 at 4.3-51. PG&E Reply Brief at 328-329 and 353. The forecast for Community Rebuild is separately addressed, expect where noted.

[742] Parties sought permission and filed Sur-Reply Briefs in response to PG&E's proposal. Sur-Reply Briefs were filed on January 23, 2023. PG&E's Community Rebuild program is set forth in PG&E Ex-04 at 23-1, stating "In 2019, PG&E initiated the Community Rebuild Program

Footnote continued on next page.

Community Rebuild miles and costs, which are addressed in Section 4.23, herein, because PG&E presents its final undergrounding proposal as a combined forecast, with both Community Rebuild miles and the larger undergrounding as part of MAT 08W with its System Hardening undergrounding miles (and did not provide figures separately for these two projects). The number of miles and costs forecasted for Community Rebuild are minor in comparison to PG&E's larger undergrounding proposal.

Table 4-C – PG&E's Modifications to System Hardening Forecast: Miles of Covered Conductor and Undergrounding[743]

Date of Proposal	2023 Miles	2024 Miles	2025 Miles	2026 Miles	Total Miles
June 30, 2021 Original Covered Conductor Miles[744]	423	405	405	405	1,638
Feb 25, 2022 Revised Covered Conductor Miles[745]	170	50	50	50	320
December 9, 2022 No Change to Covered Conductor (Same as above)	170	50	50	50	320
June 30, 2021 Original Underground Miles[746]	63	59	54	45	221

to rebuild PG&E's distribution electric and gas system infrastructure following the 2018 Camp Fire, which devastated the Town of Paradise and surrounding areas in Butte County." PG&E's forecast for Community Rebuild includes three lines of business, Electric Operations, Gas Operations, and Customer Care. These initiatives overlap in certain respects and, in addition, PG&E's presentation of these two initiatives does not always clearly separate the forecast.

743 This chart includes forecasted miles for two programs that are tracked in MAT 08W, PG&E's larger undergrounding proposal and the portion of PG&E's Community Rebuild (Town of Paradise) which are in Tier 2 and 3 in HFTD. The Community Rebuild forecasts are separately addressed at Section 4.23, herein.

744 PG&E Ex-04 at 4.3-51.

745 PG&E Ex-04 at 4.3-51.

746 PG&E Ex-04 at 4.3-51, Table 4.3-10, lines 5 and 8.

Feb 25, 2022 First Revised Underground Miles[747]	382	786	990	1,200	3,358
December 9, 2022 Second Revised Underground Miles[748]	308	415	527	750	2,000

Table 4-D – PG&E's Undergrounding and Covered Conductor Forecast Modifications to System Hardening Capital Expenditures ($000) [749]

Date of Proposal	2023	2024	2025	2026	Total Capital
June 30, 2021 Original Covered Conductor Cost[750]	$642,960	$625,949	$627,523	$629,109	$2,525,541
Feb 25, 2022 Revised Covered Conductor Cost[751]	$265,377	$81,507	$83,918	$86,402	**$517,204**
December 9, 2022 No Change in Covered Conductor on	$265,377	$81,507	$83,918	$86,402	**$517,204**
June 30, 2021 Original Underground Cost[752]	$265,987	$254,022	$236,930	$188,100	$945,039
Feb 25, 2022 First Revised Underground Cost[753]	$1,246,650	$2,459,839	$2,934,731	$3,337,360	$9,978,580
December 9, 2022 Second Revised Underground Cost[754]	$997,206	$1,288,141	$1,554,386	$2,085,850	**$5,925,983**

[747] PG&E Ex-04 at 4.3-51, Table 4.3-11, lines 5 and 8.

[748] PG&E Reply Brief at 329.

[749] This table includes forecasted cost for two programs, that are tracked in MAT 08W, PG&E's larger undergrounding proposal and the portion of PG&E's Community Rebuild (Town of Paradise) which are in Tier 2 and 3 in HFTD. The Community Rebuild forecasts are separately addressed at Section 4.23, herein.

[750] PG&E Ex-04 at 4.3-51, Table 4.3-10, lines 4 and 7 (includes Community Rebuild (MAT 95F) of 100 miles).

[751] PG&E Ex-04 at 4.3-51, Table 4.3-11, lines 4 and 7 (includes Community Rebuild (MAT 95F) of 100 miles).

[752] PG&E Ex-04 at 4.3-51, Table 4.3-10, lines 4 and 7 (includes Community Rebuild of 100 miles (MAT 95F and MAT 08W).

[753] PG&E Ex-04 at 4.3-51, Table 4.3-11, lines 4 and 7 (includes Community Rebuild of 100 miles (MAT 95 and MAT 08W).

[754] PG&E Reply Brief at 352, Table 4-8.

Parties commented on the frequency and magnitude of PG&E's System Hardening forecast changes regarding undergrounding and covered conductor. Cal Advocates states that the numerous and significant changes to PG&E's forecast hindered its ability to perform a comprehensive analysis.[755] Similarly, AARP states that "Neither the Commission nor stakeholders have had the opportunity to adequately consider the pros and cons of the available alternatives to the pros and cons of undergrounding" due to PG&E's numerous revisions.[756] Cal Advocates and other parties point out that an analysis was particularly difficult because PG&E presented changes after opportunities for party comments had passed according to the proceeding's adopted procedural schedule.[757] AT&T also finds that "PG&E made material changes to the scope of its proposed undergrounding" but after evidentiary hearings had been held.[758]

Because PG&E changed its System Hardening proposal in its December 9, 2022 reply brief, the Commission granted parties permission to file sur-reply briefs on PG&E's new proposal. Sur-reply briefs were filed on January 23, 2023, providing parties with approximately six weeks to analyze and prepare written responses to PG&E's December 9, 2022 proposal. TURN explains that "each change necessitated additional time and process" and described PG&E's proposal for System Hardening as a "moving target."[759]

Beyond these procedural and scheduling challenges, parties raise substantive questions and speculate on the rationale for PG&E's numerous

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[755] CALPA Ex-07 at 12.

[756] AARP Opening Brief at 27.

[757] TURN Sur-Reply Brief at 5-6.

[758] AT&T Sur-Reply Brief at 1-2.

[759] TURN Sur-Reply Brief at 9.

changes. For example, TURN suggests that PG&E's reductions of approximately 1,200 miles to its undergrounding proposal filed on December 9, 2022 was a result of PG&E senior leadership's concern about a number of issues affecting the executability of the 3600 mile undergrounding proposal made in February 2022, including the need for environmental permits, Caltrans permits, municipal permits, land right acquisition from public and private entities, coordinating with local stakeholders and landowners, and CEQA review.[760]

Cal Advocates raises a different concern about adherence to the Commission's Rate Case Plan, stating that PG&E's significantly different proposals for undergrounding presented in February 2022 and December 2022 were never vetted through the RAMP process, which is an integral part of the Commission's framework for evaluating the reasonableness of a cost proposal prior to a general rate case.[761] PG&E acknowledges that its significantly expanded undergrounding proposal was not included in its RAMP proceeding (A.20-06-012 filed June 30, 2020), stating that "PG&E modified its portfolio of mitigations [including System Hardening] since filing the 2020 RAMP Report."[762] "PG&E's forecast in the 2020 RAMP Report [was approximately 440 miles]."[763] PG&E now plans to install 2,000 miles of underground system hardening, a proposal never vetted through RAMP. PG&E explains this absence by stating that, as PG&E reported in its RAMP proceeding, it has continued to "refine its

760 TURN Sur-Reply Brief at 6.

761 Cal Advocates Opening Brief at 151.

762 PG&E Ex-04 at 4.3-20.

763 PG&E Ex-04 at 4.3-20.

strategy and improve the scope of the System Hardening Program. The exact scope of PG&E's System Hardening Program will continue to evolve…."[764]

Comcast points out that, while PG&E announced a "staggering" undergrounding proposal nine months into the proceeding, PG&E has not provided sufficient information about the location of the lines it plans to underground and has failed to address how it intends to address service drops, secondary lines, and the conversion of customer electric panels."[765]

The frequency and magnitude of PG&E's modifications to its System Hardening proposal may have impacted the ability of parties to effectively prepare their case. A more complete analysis by parties of PG&E's System Hardening forecasts would likely have produced more insights into the reasonableness of PG&E's final proposal, which, as described by AT&T, is flawed by "enormous uncertainty."[766]

The Commission focuses on the reasonableness of PG&E's current proposal and forecast, as reflected in PG&E's December 9, 2022 reply brief, but takes into account the frequency and magnitude of PG&E's modifications and how these modifications may have impacted parties' abilities to prepare. PG&E's December 9, 2022 System Hardening proposal and PG&E's arguments in support of the adoption of its forecast for undergrounding and covered conductor are summarized below. The Commission also addresses the comments by parties in opposition to and in support of PG&E's forecast.

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764 PG&E Ex-04 at 4.3-20.

765 Comcast Sur-Reply Brief at 2-4.

766 AT&T Opening Brief at 1.

4.3.2. System Hardening Forecast – Undergrounding and Covered Conductor

The tables above show that PG&E's June 30, 2021 forecast included plans to underground a total of 182 miles at approximately $945 million in forecasted capital expenditures (2023-2026).[767] On December 9, 2022, PG&E revised its forecast to include plans to underground a total of 2,000 miles at approximately $5.9 billion in forecasted capital expenditures (2023-2026).[768]

PG&E's 2023 expense forecast is $11.6 million and remained unchanged.[769]

PG&E's initial covered conductor proposal totaling 1,638 miles at total capital expenditures of approximately $2.5 billion and its final much smaller proposal totaling 320 miles at a total capital expenditure forecast of $517 million (2023-2026).

PG&E states that the primary objective of its undergrounding program is to target areas where (1) the wildfire threat is highest, and (2) the disruptions to customers and communities from PSPS and EPSS are highest.[770] To that end, PG&E proposes to conduct its work throughout its HFTD. PG&E's risk model has HFTD overhead exposure miles separated into 25 tranches with varying levels and combinations of consequence and likelihood of wildfire ignition risks. PG&E has proposed to do work in all 25 tranches rather than prioritizing its

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[767] PG&E Ex-04 at 4.3-51. PG&E Reply Brief at 328-329 and 353. The 2,000 miles forecast does not include Community Rebuild forecast of 100 miles.

[768] PG&E Reply Brief at 328, Table 4-1 and at 334, Table 4-5 (top row – "Adjusted" miles). TURN presents $5.9 billion by combining all MAT 08W miles shown in PG&E Reply Brief at 334, Table 4-5 (top row – "Adjusted" miles), with MAT 95F miles. TURN Sur-Reply Brief at 1.

[769] PG&E Ex-04 at 4-19 and 4-29. This amount includes other lesser costs forecasted within System Hardening.

[770] PG&E Reply Brief at 334.

work by tranches with the highest risk reductions.[771] PG&E asserts its proposal of 2,000 miles of undergrounding will mitigate the ignition risk of the lines placed underground by 99%[772] and reduce the wildfire risk in PG&E's HFTDs by "up to 20%" between 2024 and 2026.[773] PG&E also confirms that its proposal does not eliminate the use of other mitigation methods, as PG&E states it will continue its reliance on EPSS, PSPS, and other mitigations to reduce risk while PG&E engages in the process/construction of undergrounding its electric distribution infrastructure.[774] PG&E plans to rely on EPSS and PSPS in times of increased fire risk while underground construction is underway.

Parties provide analysis and recommendations in response to PG&E's capital expenditure forecast for undergrounding and covered conductor. The Coalition of California Utility Employees supports PG&E's forecast while other parties contest PG&E's capital expenditure forecast, including: Cal Advocates,

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[771] PG&E Ex-85.

[772] While parties to this proceeding do not dispute the assertion by PG&E that a risk of ignition of a line placed underground is reduced by 99% and the Commission does not test the legitimacy of this percentage reduction in this proceeding, recent publications by the Office of Energy Infrastructure Safety raise doubts, stating "PG&E calculates undergrounding effectiveness to be 99 percent; however, this does not account for remaining risk associated with secondary and service lines.... Approximately 12 percent of PG&E's CPUC-reportable ignitions from 2019 to 2022 were caused by secondary or service lines in the HFTD. According to PG&E, "[most], if not all, of PG&E's undergrounding projects have associated secondary and service lines." This means that PG&E's current calculation of percent effectiveness does not reflect the remaining risk associated with secondary and service lines, despite observed ignitions from those sources." June 22, 2023 Revision Notice for PG&E's 2023-2025 WMP Office of Energy Infrastructure Safety Docket 2023-2025 WMPs at 16. (Footnotes omitted.)

[773] PG&E Reply Brief at 335; PG&E Ex-04 at 3-6. PG&E explains that its 20% is based on its proposal in its Reply Brief (and does not include work in 2023). PG&E Opening Brief at 370, PG&E explains that some of its analysis does not include 2023 because 2023 is already in progress, stating "PG&E's analysis in this instance included only 2024-2026 because PG&E's 2023 workplan is already in progress and was based on an earlier version of the risk model (WDRM v2 for 2023 and WDRM v3 for 2024-2026)."

[774] PG&E Reply Brief at 335.

TURN, Wild Tree Foundation, MGRA, AARP, AT&T, Comcast, California Farm Bureau Federation. TURN and Cal Advocates provide the Commission with specific forecasts for System Hardening to consider. Other parties disagree with PG&E's approach reflected in its forecast for System Hardening, especially PG&E's reliance on undergrounding, but do not present alternative forecasts for System Hardening. The alternative recommended forecasts provided by TURN and Cal Advocates are summarized in the chart below. Information regarding AARP's recommendations is also included. No party contests PG&E's 2023 expense forecast for System Hardening of $11.595 million.

Table 4-E: PG&E and Parties - Comparison of Capital Expenditures for Undergrounding + Covered Conductor within System Hardening ($1,000)

System Hardening	2020 Recorded	Party	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
Covered Conductor/ Overhead	$484,915	PG&E[775]	$288,000	$366,000	$265,377	$81,507	$83,918	$86,402
		TURN[776]			$358,200	$367,871	$377,804	**$388,005**
		Cal Advocates[777]	$120,428	$366,000	$265,377			
		AARP[778]			$320,822	$311,764	$312,367	**$312,974**
Underground ing		PG&E[779]	**$86,120**	**$611,250**	$1,192,578	$2,415,857	$2,907,625	**$3,337,360**
		TURN[780]			$166,888	$158,209	$148,941	**$139,057**
		Cal Advocates[781]	**$31,842**	**$203,565**	$196,058			
		AARP[782]			$320,822	$311,764	$312,368	**$312,974**

775 PG&E Ex-04 at 4.3-25 (Table 4.3-7).

776 TURN Ex-11 at 4.

777 CALPA Ex-07 at 10.

778 AARP Ex-01 at 77.

779 PG&E Ex-04 at 4-27 (Table 4-5).

780 TURN Ex-11 at 4.

781 CALPA Ex-07 at 10.

782 AARP Ex-01 at 8. Values in testimony expressed as reduction amounts. Calculated by subtracting reductions from PG&E request.

TURN presents the most comprehensive alternative forecast for System Hardening, which recommends that PG&E rely more on covered conductor and less on undergrounding. TURN's proposal is based on the installation of approximately 450 miles of covered conductor each year, 2023 through 2026 (1,800 total miles), together with 50 miles of undergrounding per year, 2023 through 2026 (200 total miles).[783] TURN's recommended forecast is $1.581 billion (2024-2026) or 30.5% of PG&E's forecast. TURN states that its proposal, which includes PG&E targeting undergrounding in the areas of the top wildfire risk circuits together with using other mitigations, achieves almost the same amount of risk reduction as PG&E's proposed undergrounding.[784]

Below the Commission addresses the alternative forecast offered by TURN together with the arguments by other parties that contest PG&E's forecast for System Hardening.

4.3.3. Risk Mitigation of Fire Ignition from Electric Overhead Infrastructure

All parties agree that PG&E must continue work to mitigate the risk of wildfire caused by overhead distribution assets. Parties disagree on what is the just and reasonable set of wildfire mitigations, and the resulting capital expenditure forecast. Parties propose less capital-intensive mitigation measures than undergrounding, such as covered conductor, which is a proven technology

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[783] The $1.581 billion recommendation by TURN reflects three years 2024-2026, whereas the $2.1 billion recommendation reflects four years, 2023-2026, which is the length of this rate case period. TURN Ex-11 at 20-21. The Commission notes that TURN's covered conductor proposal of 1,800 miles (2023-2026) is a 463% increase over PG&E's current proposal of December 9, 2021 but only a 10% increase over PG&E's June 30, 2021 proposal.

[784] TURN Sur-Reply Brief at 8, *citing to* TURN Ex-11 at 20-45 and Table 12 at 45.

with minimal construction barriers.[785] PG&E heavily relies on the risk reduction potential of its undergrounding proposal to support its requested $5.9 billion capital expenditure forecast, essentially reasoning that the Commission must adopt its cost forecast of $5.9 billion because the other cost proposals do not eliminate risk, and asserting that risks will be reduced by 99% where undergrounding is installed.[786] PG&E concludes that other mitigation measures result in an unacceptably high level of risk as compared to its plan to eliminate risk.

The desire to eliminate risk, rather than mitigate risk in high risk areas, is a major premise of PG&E's argument in support of its $5.9 billion forecast. PG&E asserts: "distribution overhead assets represent a high ignition risk due to a combination of high exposure (i.e., many overhead assets located in or crossing through HFTD areas) and proximity to risk factors such as vegetation."[787] PG&E asserts its proposal will result in "the near-total elimination of wildfire risk caused by utility assets in the areas undergrounded.", PG&E asserts that if it does not underground its lines, customers will continue to face unreasonable risks, stating: "restricting or postponing undergrounding, as parties recommend, puts PG&E's customers and communities at unreasonable risk and should be

[785] PG&E Ex-04 at 4.3-44, stating "[C]urrently the most frequently used method for system hardening is overhead hardening along the existing alignment. Overhead system hardening can often be done more quickly than line relocation or undergrounding, by taking advantage of existing rights and easements."

[786] PG&E Reply Brief at 363; PG&E Ex-04 at 3-2, stating "PG&E's undergrounding program reduces ignition risk by approximately 99 percent because it eliminates vegetation, animal, and other potential sources of contact with electric lines."

[787] PG&E Opening Brief at 378.

rejected by the Commission."[788] PG&E claims its costs are justified based on its assertion that undergrounding achieves 99% risk reduction.[789] PG&E opposes TURN's proposal, which relies on installation of covered conductor as the preferred mitigation, and which PG&E states reduces risks by 62% (when used alone),[790] asserting that covered conductor does not provide sufficient risk reduction.[791]

As stated above, parties agree PG&E must continue work to mitigate the risk of wildfire caused by overhead distribution assets and, in addition, agree that undergrounding a distribution line could very substantially mitigate risk of wildfire ignition from that undergrounded line as long as parts of the line are not left overhead.[792] Parties disagree about the just and reasonable set of wildfire risk

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788 PG&E Reply Brief at 358. PG&E Reply Brief at 335, clarifying that the 99% risk reduction only applies to assets placed underground and PG&E estimates that its 2,000 miles of undergrounding proposal, submitted on December 9, 2022, will reduce wildfire risk through undergrounding in the HFTD by up to 20% between 2024 and 2026. PG&E's risk reduction estimate includes reliance on EPSS, PSPS and other mitigations to reduce risk while undergrounding occurs.

789 TURN Opening Brief 381, stating "PG&E's every attempt to compare its "all-in undergrounding" approach to another approach is based on PG&E's unstated assumption that spending more money to eliminate risk with just undergrounding is the preferable risk mitigation solution."

790 PG&E's assertion of 62% effectiveness but this figure may be higher based on a recent study submitted with PG&E's 2023-2025 Wildfire Mitigation Plan, stating "The information compiled and assessments completed in 2022 continue to indicate CC effectiveness between approximately 60 to 90 percent in reducing the drivers of wildfire risk, consistent with benchmarking, testing and utility estimates." PG&E 2023-2025 Wildfire Mitigation Plan, Appendix D, 2023 -2025 WMP Joint IOU Covered Conductor Working Group Report at 1.

791 PG&E Opening Brief, 370, 386, 392, 419, and 424.

792 PG&E Reply Brief at 335 and 338. TURN Opening Brief at 381, explaining that the use of covered conductor alone is not supported by any parties but rather parties suggest a combination of covered conductor together with various other mitigation measures, such as PSPS and EPSS.

mitigations to balance risk reduction and costs and the appropriate amount of undergrounding given its high cost and risk reduction.

While it is not possible to eliminate all risk, parties disagree about what is the appropriate balance of risk reduction and costs, while considering feasibility, including permitting and construction timelines. TURN argues that PG&E's proposed near-elimination of risk in undergrounded lines, in the absence of consideration of other factors, such as costs or construction timelines, is not a reasonable goal. Parties further claim that fire ignition risk reduction with the aggressive installation of covered conductor used together with other mitigation measures, such as an increased focus by PG&E on vegetation management, equipment inspection, and related projects, presents a reasonable overall reduction of risk in HFTDs during this rate case period of 18% compared to PG&E's overall risk reduction of 20% by relying on its undergrounding assumptions and covered conductor is significantly less costly.[793]

PG&E asserts that undergrounding a distribution line will reduce the risk of wildfire ignition by 99%.[794] This Commission finds that undergrounding a distribution line substantially reduces the risk of wildfire ignition, but does not determine the accuracy of PG&E's assertion that it reduces risk of wildfire

[793] PG&E Opening Brief at 386. "PG&E would achieve a risk reduction of just 18 percent during the 2024-2026 period, with more covered conductor (which does not completely eliminate risk), leaving a substantial portion of HFTD areas at higher risk." TURN Sur-Reply Brief at 7-8, stating "PG&E calculates that its reduced undergrounding work would eliminate 20% of wildfire risk in 2024-2026, while PG&E previously calculated that TURN's covered conductor proposal for 2024-2026 would eliminate 18% of the wildfire risk. TURN forecasts a cost of $1.581 billion for its plan, or **less than 20% of PG&E's revised undergrounding cost forecast** for 2024-2026. At least for this rate case cycle, therefore, PG&E's proposal to spend over seven billion dollars more than TURN's proposed program provides extremely little additional wildfire risk reduction and begs the question of what is the additional benefit that might warrant such a huge cost difference. (Emphasis in original; footnotes omitted.)

[794] PG&E Reply Brief at 335.

ignition by 99%. The Commission further finds that it is undeniable that the risk of wildfire must be reduced and that the harm caused by wildfire can be catastrophic. While PG&E focuses its attention on its purported and aspirational "near-total elimination of risk" on undergrounded lines, instead, PG&E must focus on consideration of risk on the entire system and accounting for the feasibility of work. Importantly, the "near-total elimination" of risk on each individual line depends on PG&E timely and successfully completing its undergrounding proposal. Project delays would lead to the highest risk scenario: bare overhead wire in HFTDs. Other proposals, discussed in more detail below, could potentially reduce wildfire risks by approximately 18% through a combination of aggressive use of covered conductor in combination with other mitigation measures. However, risk reduction alone is not a sufficient metric to judge the prudency of the proposed mitigations. Risk Spend Efficiency (RSE) values, which are a ratio of risk reduction and costs, must be considered, in addition to other factors, such as costs, feasibility of construction, timeline for completion, and impact on telecommunications companies. The ratepayers' ability to pay for safety or risk reduction is not unlimited; as with all safety measures, the Commission must consider the cost and impact on affordability. Cost considerations, as well as these other critical concerns, are discussed below.

4.3.4. Costs of Undergrounding as Compared to Covered Conductor

PG&E's forecast for its undergrounding proposal is significant, at approximately $5.9 billion (2023-2026) in capital expenditures plus approximately $11 million in projected expense.[795] The Commission must evaluate what mix of wildfire mitigation activities, including undergrounding

[795] PG&E Ex-04 at Tables 4.3-6 and 4.3-7 at 4.3-24; PG&E Reply Brief at 328 (Table 4.1).

and covered conductor, are just and reasonable and balance both risk reduction, feasibility, timeline, and cost containment. For purpose of system hardening, PG&E explains that covered conductor is an alternative, stating: "[C]urrently the most frequently used method for system hardening is overhead hardening along the existing alignment. Overhead system hardening can often be done more quickly than line relocation or undergrounding, by taking advantage of existing rights and easements."[796]

To provide context regarding the magnitude of PG&E's approximately $5.9 billion undergrounding cost forecast, a comparison between PG&E's recent actual recorded amounts in 2021 and forecast for 2022 versus PG&E's planned spend for 2023-2026 is informative. PG&E's 2021 recorded capital expenditures for undergrounding is approximately $127 million, while its undergrounding capital forecast for 2023-2026 is approximately $5.9 billion and the 2023 undergrounding capital forecast is approximately $1 billion.[797] PG&E provides no alternative smaller or less costly System Hardening proposal to its $5.9 billion capital forecast.[798] From another perspective, PG&E projects its Electric Distribution plant-in service to increase from approximately $45 billion in 2023 to approximately $64 billion in 2026 and its Electric Distribution rate base to increase from approximately $26 billion in 2023 to approximately $40 billion in

[796] PG&E Ex-04 at 4.3-44.

[797] PG&E Reply Brief at 328.

[798] Details regarding MAT 95W (Community Rebuild) are available at PG&E Ex-04 at Ch. 23. The Community Rebuild program is not contested. The Community Rebuild program not the same as PG&E larger undergrounding proposal because, while MAT 08W includes the demolition of above ground systems and placing those systems underground, MAT 95W (Community Rebuild) includes rebuilding in an area where the distribution system was destroyed by wildfire with a new distribution system is being constructed underground. In short, no above ground system currently exists.

2026.[799] These increases are largely driven by PG&E's $5.9 billion undergrounding proposal in this proceeding.

Within this context, the Commission now evaluates the reasonableness of PG&E's undergrounding proposal based on the information presented by parties, which cover a number of factors, including cost per mile, risk reduction, total costs, and feasibility of both undergrounding and reasonable alternatives, such as covered conductor.

First, we turn to the question of cost per mile. PG&E generally estimates $1.6 million per mile for installation of covered conductor during 2023-2026.[800] TURN presents a lower estimate of approximately $800,000 per mile and MGRA refers to a report prepared under the direction of the Office of Energy Infrastructure Safety, the Exponent Report, that projects cost efficiencies gained over time.[801] TURN's cost estimate is based its own analysis and on SCE historic costs of $629,000 per mile (which include pole replacements and additional poles to shorten spans).[802] TURN's cost estimate omits other asset replacement on the

[799] PG&E Ex-64 (JCE Vol. II) at 4-57 and 4-59. Costs rounded to nearest thousand. PG&E Reply Brief at 352. The capital costs noted are tracked in MAT 08W, which isolates PG&E's undergrounding proposal, in contrast with the capital costs noted in 95W, which are those undergrounding costs associated with PG&E's ongoing Community Rebuild program.

[800] PG&E Ex-17 (Rebuttal) at 4.3-39.

[801] TURN Opening Brief at 416-417; MGRA Opening Brief at 54 (fn. 135), *citing to* Exponent Report (December 22, 2021) *Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review.* The Exponent Report is available as an attachment to PG&E's 2022 Wildfire Mitigation Plan (February 25, 2022) on the website of the Office of Energy Infrastructure Safety.

[802] TURN Opening Brief at 416-417, stating "TURN's position is that overhead system hardening overhead work should not include replacement of useful assets that do not pose significant ignition risk and are not necessary for the installation of covered conductor. TURN recommends that as part of its covered conductor installation, PG&E install all the poles it needs to support the heavier conductor, replace all minor pole attachments such as cross arms, and replace all non-exempt fuses. However, TURN recommends that PG&E not replace

Footnote continued on next page.

poles, but TURN presents a more conservative estimate for replacing certain component parts than PG&E.[803] TURN's cost estimate provides a premium of 26% over SCE's recorded 2021 unit costs to deploy covered conductor.[804]

TURN and PG&E disagree as to whether replacement of other assets on the pole is necessary when covered conductor is installed and whether or not SCE's historic costs per mile are a helpful benchmark. PG&E's estimate includes work beyond installing covered conductor, including nearly 100% of pole replacement and numerous initiatives to replace equipment and components, including materials and labor.[805] PG&E explains "it is reasonable to replace all the components of the covered conductor system at the same time because installing different components at different times carries the risk of requiring a re-sizing of the pole and requiring a second pole replacement or other redundant component replacements for compatibility."[806] PG&E's 2023 unit cost forecast is based on its 2020 recorded cost of $1.8 million per mile with certain adjustments.[807] TURN responds that PG&E should narrow the scope of the assets replaced when it installs covered conductor, stating: "some assets simply need not be replaced until they deteriorate, which could be many years in the future."[808]

In response to TURN's arguments, PG&E states:

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transformers, animal protection upgrades, reclosers, switches, surge arresters, and voltage regulators, if those assets are in safe working condition."

[803] TURN Opening Brief at 416-417.

[804] TURN Ex-11 at 23.

[805] PG&E Ex-17 (Rebuttal) at 4.3-40.

[806] PG&E Opening Brief, 423.

[807] PG&E Ex-17 (Rebuttal) at 4.3-41.

[808] TURN Opening Brief at 419.

"…TURN's analysis fails to address three key factors that drive the difference in cost between SCE and PG&E: vegetation management; pole replacement; and equipment upgrades.

First, vegetation clearing in support of a new overhead line can significantly increase PG&E's costs for overhead system hardening projects. Both the increased height of the poles, the widened cross-arms, and the increased sag of the line (all due to the weight of the covered conductor) can vary the cost considerably. This cost alone can add between $50,000 to $400,000 per mile depending on the terrain and the location of the line. The rural, more heavily-wooded nature of HFTDs in PG&E's service territory where the work is completed drives the need for additional vegetation clearing. SCE reports it has not generally observed significant vegetation management or access road rehabilitation costs across its installations in its less heavily-wooded territory. This critical cost-driver difference is not acknowledged by TURN.

Second, in connection with pole replacement costs, PG&E replaces nearly 100 percent of its poles due to the additional weight/sag of the new covered conductor. SCE only replaces, on average, 10 to 12 poles which represents approximately 34 percent to 41 percent of the average number of poles per circuit mile.

Third, the equipment upgrades PG&E completes during its overhead hardening work also increase PG&E's costs relative to SCE. PG&E incorporates numerous initiatives into a single hardening project. Non-exempt equipment and ignition-component replacements significantly adds to costs due to the material and labor installation costs of the new equipment. SCE generally is focused on covered conductor only and does not include other major equipment upgrades."[809]

[809] PG&E Opening Brief on at 425-426.

The Commission finds that $1.261 million per mile for 2023 with escalating costs for 2024-2026 for installation of covered conductor presents a reasonable estimate for wildfire mitigation aspects of the installation of covered conductor, and a reasonable middle ground between TURN and PG&E's proposals. PG&E's proposed escalations for covered conductor are 4.43% for 2024), 2.96% for 2025, and 2.96% for 2026; this results in covered conductor unit costs of approximately $1.33M per mile in 2024, $1.38M per mile in 2025, and $1.43M per mile in 2026. TURN's estimate of $800,000 per mile likely reflects a narrower scope of work than what is reasonable, which may artificially drive down the cost forecast of covered conductor. PG&E notes: "PG&E's overhead assets are aging at a pace faster than the assets can be replaced. This is especially the case in non-HFTD."[810] We observe this is consistent with the 2022 Commission-appointed Independent Safety Monitor report, which stated that "Across the divisions (e.g., Transmission, Distribution, Gas, etc.), the ISM has observed numerous PG&E asset ages that are significantly older than the related industry average useful life and the related PG&E average age of asset failure."[811] Given PG&E's aging infrastructure, there is high value in doing all work needed at a given site while work crews are out at such site, but we expect PG&E to be judicious about which equipment requires replacement. As a result, we find that a unit cost of $1.261M strikes an appropriate balance between funding needed onsite asset replacement work and containing costs. This will help ensure that PG&E prioritizes equipment replacement work for sites that need it the most.

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[810] PG&E Ex-17 on at 13-12 to 13-13.

[811] ISM Report at 6. https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/pge/oversight-and-enforcement/ism-status-update-report-q3-2022.pdf. Commission Resolution M-4855 describes the Independent Safety Monitor appointment.

With respect to establishing a reasonable estimate for the cost per mile of undergrounding, a number of different variables should be evaluated as part of this analysis. First, no party disputes that a mile of undergrounding corresponds to replacement of less than a mile of overhead assets because, for example, topographical construction hindrances require longer routes when undergrounding distribution assets.[812] The conversion factor used by PG&E to calculate the overhead exposure per mile undergrounded is 1.25.[813] TURN notes that if PG&E undergrounds, for example, 2,000 miles of assets, PG&E will likely de-energize significantly less than 2,000 of overhead assets.[814] We find reasonable PG&E's 1.25 conversion factor for the purpose of establishing a reasonable cost estimate for undergrounding.

A second consideration is whether PG&E's claim of decreasing costs for undergrounding over time is persuasive. In this proceeding, PG&E states that its undergrounding costs will trend downward over time, with its 2023 per mile forecast of $3.3 million decreasing over this rate case period to approximately $2.8 million in 2026 (four-year average cost of $2.97 million).[815] At the same time

[812] TURN Sur-Reply Brief at 7-8, stating that a mile of undergrounding eliminates only 0.64 to 0.80 miles of overhead covered conductor, due to the need to re-route undergrounding to address various construction feasibility issues and, as such, PG&E's proposal to underground about 1,700 miles equivalent to eliminating risk on 1,080 to 1,350 miles of overhead line.

[813] For example, if a utility were to convert one mile of overhead lines, PG&E assets it would need to install 1.25 miles of underground lines. Therefore, according to PG&E's assertion, it follows that to approximate the costs of covered conductor as compared to undergrounding, the estimated costs of undergrounding one mile should be multiplied by 1.25, which equal approximately $4.2 million. The figure of $4.2 million would be compared to the cost of installing one mile of covered conductor at $800,000.

[814] TURN Ex-11 at 33.

[815] PG&E Ex-04 at 4.3-51 (Table 4.3-11 and Table 4.3-11) PG&E's June 30, 2021 forecast cost data for undergrounding decreased in the February 25, 2023 forecast from $4.3 million (2020 unit costs) to $3.7 million (2020 unit costs).

PG&E acknowledges a high level of uncertainty surrounding its cost forecast, stating "[T]here continues to be significant uncertainty and variability associated with wildfire mitigation activities and their associated costs. As an example, the exact scope of PG&E's System Hardening Program will continue to evolve as PG&E performs detailed planning and engineering for the remaining circuit miles to be hardened…. [T]here is uncertainty regarding the wildfire mitigation costs PG&E ultimately will incur versus forecast in this GRC."[816] In response to this level of cost uncertainty, MGRA suggests that the Commission significantly scale back PG&E's proposal to a "pilot program" until PG&E can demonstrate cost efficiencies, which are speculative as the highest fire threat areas are often in the most challenging terrain.[817] Here, this Decision approves a portion of PG&E's undergrounding proposal, and provides PG&E an opportunity to demonstrate its capabilities to achieve its forecasted decreasing unit costs, to achieve sufficient risk reduction, and to complete its undergrounding work on the timeline forecast in this GRC. We require PG&E to report on its progress pursuant to the accountability discussion in Section 4.3.7 below.

A third aspect of determining a cost estimate for undergrounding is that PG&E asserts, while undergrounding is costly, the potential exists for significant cost savings in other areas of its business as a result of undergrounding. In support of the high costs of its undergrounding proposal, PG&E argues that, while costly in the near-term at approximately $5.9 billion (2023-2026), its proposal will save ratepayers money in the long term by lower maintenance, tree trimming, and costs of rebuilding after wildfires.[818] TURN responds that PG&E's

[816] PG&E Ex-04 at 4-23.

[817] MGRA Ex-01 at 84 and 91.

[818] PG&E Ex-04 at 4.3-11.

effort to justify the capital expenditure forecast for its undergrounding proposal by future cost savings and potential decreasing costs of construction is unconvincing, stating "covered conductor is still significantly more affordable than undergrounding even when one considers long-term savings from undergrounding."[819]

Parties do not present actual undergrounding cost figures to compare with PG&E's forecasted costs but point to the significant unknowns surrounding this process and assert that these costs are hard to predict because PG&E has no actual experience at undergrounding 2,000 miles within four years.[820] Over approximately six years, between 2015 and 2021, PG&E completed a total of 155 miles of undergrounding, an average of 22 miles per year.[821] In 2022, PG&E completed approximately 180 miles of undergrounding (120 miles System Hardening and 60 miles Community Rebuild in Butte County), representing a 146% increase over the approximate 73 miles undergrounded in 2021.[822].

The Commission finds that PG&E's estimates of decreasing undergrounding costs over time appropriately pursue efficiencies for customers and potential savings, but require testing before approving the project at a larger

[819] TURN Opening Brief at 400-402.

[820] TURN Opening Brief at 399, stating "PG&E's ability to complete such a dramatic escalation in undergrounding is extremely suspect. TURN witness Borden closely examined some of the materials provided by vendors responding to PG&E's Request for Information for undergrounding work.1173 Vendors provided large ranges of potential unit costs and 'ramping plans' - potentially achievable miles per year. These plans contained numerous caveats explaining the various risk factors that might prevent achieving both the unit cost and mileage plan estimates. Some companies believed much more modest scaling of the undergrounding program is achievable…."

[821] TURN Opening Brief at 398*, citing to* TURN Ex-11 at 35.

[822] PG&E 2023-2025 WMP at 3. PG&E 2023-2025 WMP Table PG&E-1.1-1: PG&E's Performance Against 2020-2022 Quantitative WMP Initiative Targets at 990. PG&E 2023-2025 Wildfire Mitigation Plan at 991-992 (Table PG&E-1_1-1).

scale. We note that the 2,000 miles of undergrounding in the instant application are the only plan PG&E has submitted to this Commission at this time. We recognize that PG&E plans to eventually undergrounding 10,000 miles. This decision provides PG&E an opportunity to demonstrate its capabilities at a smaller scale. We grant PG&E the opportunity to demonstrate that it can achieve its forecasted unit costs, risk reduction, and project timeliness, and report back on its results. PG&E's actual costs achieved on a unit basis, and whether they decreased over time, may be a factor in reviewing reasonableness of any future undergrounding request by PG&E.

As a result, the Commission finds that PG&E's 2023 estimated costs per mile for undergrounding of approximately $3.3 million per mile in 2023, decreasing over this rate case period to approximately $2.8 million in 2026 (four-year average cost of $2.97 million) is reasonable. This means that the escalation factors adopted in Chapter 13 of this decision are not applied to undergrounding specifically. Also, undergrounding costs in post-test years are adjusted pursuant to PG&E's forecasted decreasing unit costs.

In addition, as stated above, the Commission finds that $1.261 million per mile in 2023, increasing over this rate case period to approximately $1.396 million per mile in 2026 for purposes of installation of covered conductor is a reasonable reflection of the appropriate level of potential costs. Similarly, the escalation factors adopted in Chapter 13 of this decision are not applied to covered conductor. Post-test years for covered conductor will align with this decision's covered conductor increasing escalating unit costs.

With the unit costs established for undergrounding and covered conductor on a per-mile basis, we turn next to discuss what set of mitigations is just and reasonable and risk reduction and total costs.

For the first time in PG&E's history of General Rate Cases, this proceeding has the benefit of cost-informed risk analysis pursuant to the Safety Model Assessment Proceeding (S-MAP) Settlement adopted in D.18-12-014.[823] The S-MAP Settlement established a quantitative risk modeling methodology to prioritize risk reduction spending based on cost-effectiveness, whereby PG&E and the other settling parties agreed to use the S-MAP metrics to rank the cost-effectiveness of proposed risk reduction activities. A key metric in the S-MAP settlement was the use of RSE values, which represent a ratio of the risk reduction to the investment cost of a mitigation. RSE values allow for an apples-to-apples comparison of risk mitigation measures, and can be a guide to prioritizing projects that mitigate risk to see what projects offer the most risk reduction per dollar.

Relying on PG&E's RSE analysis for undergrounding and covered conductor in the record of this proceeding, in TURN-Ex 11 Attachment 1, TURN presents a risk modelling worksheet provided by PG&E in discovery.[824] In response to a ruling issued on June 8, 2023,[825] PG&E served its update to the service list on June 9, 2023, which updated its risk modelling worksheet to account for the new information in its Reply Brief. The updated risk modelling worksheet was admitted into evidence as PG&E Ex-85. For ease of reference, we will refer to the risk modelling worksheet in PG&E Ex-85 as the "2023 PG&E GRC Wildfire Mitigation Spreadsheet."

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[823] TURN Opening Brief at 22-23.

[824] TURN Ex-11 Attachment 1 at 51-137.

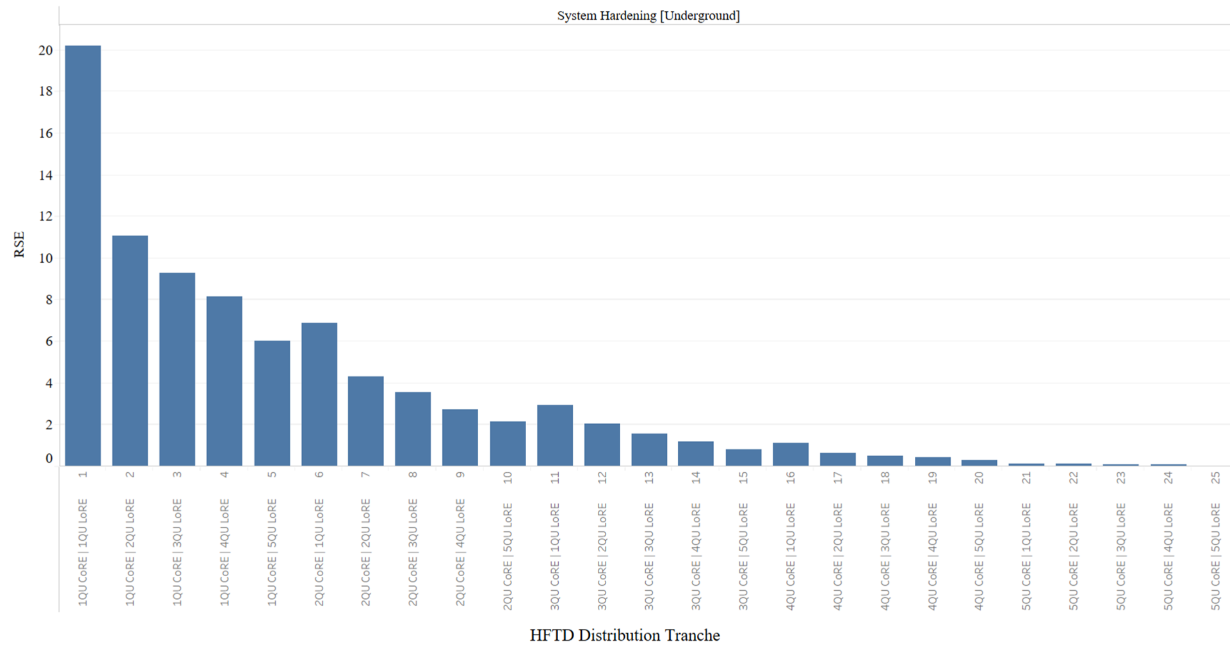
[825] Assigned Commissioner and ALJ Ruling Requesting Updated Data, June 8, 2023.

In its 2023 PG&E GRC Wildfire Mitigation Spreadsheet[826] PG&E divides its electric distribution system into 25 tranches of risk levels, each tranche with its own risk score, RSE number of undergrounding miles and covered conductor exposure miles. For each system hardening mitigation (i.e., undergrounding and covered conductor), each tranche has the 2023-2026 program risk reduction and 2023-2026 program cost which is used to calculate RSEs.

The RSE values provided by PG&E for undergrounding vary dramatically by tranche. Undergrounding the highest risk tranches results in the most risk reduction for dollars spent largely because the top six tranches contain 63% of the 2023 baseline risks. For example, the highest risk tranche has an undergrounding RSE approximately 83% higher than the RSE in the second highest risk tranche. Figure A below uses PG&E's data to graphically display the RSEs for each tranche of proposed undergrounding.

[826] PG&E Ex-85.

Figure A: PG&E's Proposed Undergrounding - Comparing RSEs by Tranche[827]



RSEs for covered conductor also vary dramatically by tranche. Installing covered conductor in the highest risk tranches results in the most risk reduction for dollars spent, again largely because the top six tranches contain 63% of the 2023 baseline risks. For example, the highest risk tranche has a covered conductor RSE approximately 79% higher than the RSE in the second highest risk tranche. Figure B below uses PG&E's data to graphically display the RSEs for each tranche of proposed covered conductor.

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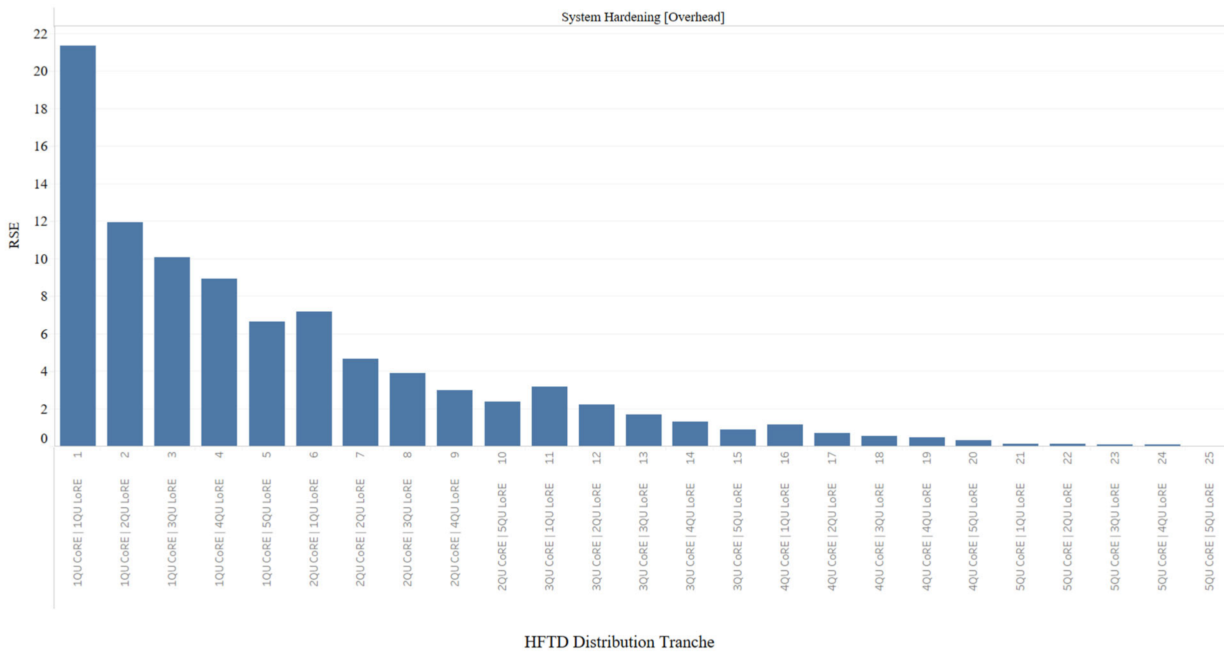
827 PG&E Ex-85, Attachment A at 2.

Figure B: PG&E's Proposed Covered Conductor - Comparing RSEs by Tranche[828]



PG&E proposed scenarios for the appropriate amount of undergrounding and covered conductor in this case that changed over time. PG&E presented its first alternative proposal in its testimony in February 2022, and modified it in its Reply Brief in December 2022. TURN made its proposal in its December 2022 Opening Brief. Figures C-D below illustrate PG&E's positions, and the proposed milage for covered conductor and undergrounding, risk reduction, and cost associated with each proposal.

[828] PG&E Ex-85, Attachment A at 2.

Figure C: Undergrounding and Covered Conductor Proposal in PG&E Supplemental Testimony Feb 2022[829]

	Miles	Overhead Exposure	Risk Reduction	2023 Baseline Risk	% Risk Reduction	Cost (million)
Undergrounding	3,346	2,677	6,766	22,140	33%	9,979
Covered Conductor	320	320	606			517
Total	3,666	2,997	7,372			10,496

Figure D: Undergrounding and Covered Conductor Proposal in PG&E Reply Brief December 2022[830]

	Miles	Overhead Exposure	Risk Reduction	2023 Baseline Risk	% Risk Reduction	Cost (million)
Undergrounding	2,000	1,590	4,096	22,140	21%	5,926
Covered Conductor	320	320	606			517
Total	2,320	1,910	4,702			6,443

The details of TURN's proposal are detailed below in Figure E:

Figure E: Undergrounding and Covered Conductor Proposal in TURN's Opening Brief December 2022831

	Miles	Overhead Exposure	% Risk Reduction	Cost (million)
Undergrounding	200	160	18%[832]	613
Covered Conductor	1,800	1,800		1,492
Total	2,000	1,960		2,105

829 PG&E's proposed miles are from PG&E Supplemental Testimony filing at Exhibit PG&E-4 at 3-27. The 2023 Baseline Risk, Risk Reduction and costs figures for PG&E's Feb 2022 proposal are from TURN-11 Atch 1 at 48-51, 54-55, 82-84, and 134-135, which is output data from PG&E's Wildfire Distribution Risk Model V. 2. Percent Risk Reduction was calculated taking the Total Risk Reduction divided by the 2023 Baseline Risk.

830 PG&E's proposed miles are from PG&E's Reply Brief at 352-353. The 2023 Baseline Risk, Risk Reduction and costs figures for PG&E's December 2022 proposal are from Exhibit PGE-85 AtchA at 3-5, 35-37, and 6835, which is output data from PG&E's Wildfire Distribution Risk Model V. 2. Percent Risk Reduction was calculated taking the Total Risk Reduction divided by the 2023 Baseline Risk.

831 TURN's proposed miles are from TURN Opening Brief at 378 and 415.

832 PG&E Opening Brief at 386.

Here, we find it reasonable to develop a hybrid approach for undergrounding and covered conductor that balances elements of both PG&E's and TURN's system hardening proposals. As illustrated by Figures A and B, we find that more risk reduction is achieved when covered conductor and undergrounding work is conducted in the highest risk areas. If PG&E appropriately prioritizes work in high risk tranches for its undergrounding, it can meet and potentially exceed the risk reduction achieved in both PG&E's and TURN's proposals. We expect PG&E to prioritize conducting a majority of its work in the highest risk areas to achieve as much risk reduction as possible. However, we also include an additional 146 miles of covered conductor as a 'buffer' to provide PG&E an opportunity to harden miles in the tranches that were not deemed as cost-effective. A 'covered conductor buffer' may yield less risk reduction, as can be seen in Figure F below, but we find that it allows PG&E to address practical project planning and execution challenges along with mitigating risks not addressed by the risk models.[833] Part of the value of allowing this buffer is to facilitate hardening in the event that there are unavoidable delays in hardening the highest risk areas, or where efficiencies can be gained by coordinating hardening with other necessary work. We allow this buffer for covered conductor, but not undergrounding, because covered conductor projects face fewer permitting and rights of way risks, which have the potential to delay undergrounding projects.

We find a hybrid scenario can capture cost savings while still achieving a high level of risk reduction, which we conservatively estimate to be 21% percent

[833] The risk reduction amount for the 'covered conductor buffer' was calculated by distributing evenly the 146 miles across the remaining 19 tranches that were not cost-effective.

or higher.[834] The hybrid scenario below reflects a mix of undergrounding and covered conductor miles based on the range of the numbers provided by the various positions of the parties. This includes PG&E's request to rapidly ramp up undergrounding and TURN's alternative system hardening program focused on use of covered conductor. Figure F below illustrates the "hybrid scenario," which blends elements of both PG&E's proposal in Figure D and TURN's proposal in Figure E.

Figure F: Hybrid Scenario for Undergrounding and Covered Conductor			
	Miles	Overhead Exposure	Cost (million)
Undergrounding	973	778	2,901
Covered Conductor	881	881	1,174
Covered Conductor Buffer	146	146	195
Total	2,000	1,805	4,270

We are persuaded elements of both PG&E and TURN's proposals have merit, and that the "hybrid scenario" is just and reasonable and strikes a balance between risk reduction, feasibility, timeliness, and cost containment. The forecasted capital cost of the "hybrid scenario" of $4.270 billion is reasonable, and is $2.173 billion less than PG&E's proposal. This decision also requires PG&E to undertake associated accountability measures, discussed further in section 4.3.7 below. This includes recording costs in the WMBA and PG&E filing a

[834] An estimate of minimum amount of risk reduction was calculated utilizing risk modeling spreadsheet in PG&E Ex-85 (i.e., "2023 PG&E GRC Wildfire Mitigation Spreadsheet"). Program exposure data for PG&E's UG proposal was utilized from the six tranches with the highest risk scores. Additionally, this same program exposure data was duplicated for System Hardening – Overhead exposure miles for the six tranches with the highest risk scores. The risk reduction was calculated for years 2023-2026 for both UG and CC exposure miles in the six highest risk tranches. This estimate is conservative because it is based on 778 UG exposure miles plus 778 CC miles, and does not estimate the additional risk reduction in the Hybrid Scenario of the 103 additional covered conductor miles plus an additional 146 covered conductor buffer miles.

System Hardening Accountability Report Advice Letter where it will demonstrate the extent to which its covered conductor and undergrounding work it has performed has reduced wildfire risk.

4.3.5. Projected Total Costs and Customer Affordability

The Commission must evaluate PG&E's forecast for affordability, informed by the affordability metrics developed in R.18-07-006.[835]

PG&E's undergrounding proposal includes a requested capital forecast of approximately $5.9 billion (2023-2026) and expense forecast of $34 million (2023-2026).[836] PG&E states it understands customer-affordability concerns "[b]ut one cannot address these concerns [affordability] at the cost of safety and reliability."[837] PG&E further states that it must engage in "bold, forward-thinking initiatives" and must be adequately funded.[838] PG&E explains that comparisons to other utilities' plans for undergrounding, which are more modest, are not reliable because PG&E's service territory presents unique challenges.[839] PG&E points out it provided updated "affordability metrics" in response to a request by TURN.[840] PG&E also states that, while the Commission's affordability metrics adopted in D.20-07-032 provide one "set of measurements that can be used to assess customer affordability, they are not the only method" and the

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[835] R.18-07-006, *Order Instituting Rulemaking to Develop Methods to Assess the Affordability Impacts of Utility Rate Requests and Commission Proceedings* (July 23, 2018).

[836] PG&E Ex-04 at 4-19 and 4-29. This amount includes other lesser costs forecasted within System Hardening.

[837] PG&E Reply Brief at 325.

[838] PG&E Reply Brief at 325.

[839] PG&E Reply Brief at 339.

[840] PG&E Opening Brief at 10; TURN Ex-615.

Commission has recognized that the adoption of affordability metrics "does not preclude" alternatives.[841]

In response TURN cites to the findings of the California Legislature in SB 599 and states that no one disputes that that living with inadequate access to gas or electric utility service "causes tremendous hardship and undue stress, including increased health risks to vulnerable populations."[842] TURN acknowledges that the Commission cannot address all issues affecting bill affordability in this proceeding but points to factors under the Commission's direct control here.[843]

According to TURN and other parties, these factors include scrutinizing the balance between reliance on undergrounding as compared to covered conductor for wildfire mitigation.[844] TURN highlights the impact of PG&E's "capital-heavy" proposed spending on customer rates in the long-term because capital costs are recovered from ratepayers over the life of the asset, which PG&E assigns a 50-year depreciation period for undergrounding.[845] TURN also points out that capital asset expenditures are incorporated into in the utility's rate base, on which PG&E earns a rate of return (7.28%).[846] TURN acknowledges that

[841] PG&E Opening Brief at 10.

[842] TURN Opening Brief at 4.

[843] TURN Opening Brief at 4.

[844] TURN Ex-11 at 19.

[845] TURN Opening Brief at 19-20.

[846] TURN Opening Brief at 19-20. PG&E's rate of return is determined in a separate proceeding before the Commission. The Commission most recent decision setting PG&E's rate of return was D.22-12-031 (as corrected by D.23-01-002), which authorized a return on rate base of 7.28% for PG&E's 2023-2026 operations (cost of capital adjustment mechanism triggers would result in an adjustment during some of these years.) TURN is suggesting that because utilities profit over time from capital projects, such as PG&E's proposed $5.9 billion capital project for

Footnote continued on next page.

covered conductor is also a capital program that adds to PG&E's rate base but that covered conductor does so at a much lower cost to ratepayers with a high overall safety benefit

A number of additional other parties also object to PG&E's proposal on the basis that it is unreasonably costly due to "affordability" concerns.
Cal Advocates states that capital expenditure forecasts presented by PG&E's undergrounding proposal should be substantially reduced for 2023 from PG&E's request of approximately $1 billion in 2023[847] to a lower amount of $197 million in 2023.[848] Cal Advocates claims that its lower recommendation is more in line with PG&E's forecast submitted to the Commission on June 30, 2021, before PG&E announced the goal of 10,000 miles of undergrounding.[849] Cal Advocates also relies on PG&E's 2021 recorded capital expenditures for underground system hardening of $31.8 million.[850] Cal Advocates explains that its forecast is substantially lower than PG&E's because it is not convinced PG&E is able to achieve the 2,000 miles projected when PG&E only completed 2.6 miles of undergrounding system hardening in 2021.[851]

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undergrounding, PG&E favors work plans for wildfire mitigation that are capital intensive because these project provide utilities with more secure profit overtime.

[847] The amount of approximately $1 billion reflects PG&E's request in its December 9, 2022 Reply Brief at 352.

[848] Cal Advocates' recommendations regarding other years are also disputed and are available at CALPA Ex-07 at 16.

[849] CALPA Ex-07 at 16.

[850] CALPA Ex-07 at 15.

[851] CALPA Ex-07 at 16, stating "…PG&E completed only 2.599 miles of underground system hardening in 2021. PG&E completed 1.483 miles of underground system hardening in 2019 and 2.254 miles in 2020. PG&E would need to substantially increase its 2021 underground system hardening mileage by 1,708 percent to reach its estimate of 47 miles in 2022." Cal Advocates does not include mile related to PG&E's efforts in the Community Rebuild program in the Town of Paradise.

TURN presents an alternative recommendation and offers a substantially reduced forecast, suggesting a capital forecast of $2.10 billion (2023-2026).[852] In support of its lower forecast, TURN states "The net cost to ratepayers of this [PG&E] initiative, if approved, would be severe and burdensome to ratepayers for decades to come, imperiling both affordability and state electrification goals."[853] Rather than authorize an approximately $5.9 billion forecast that focuses on undergrounding, TURN recommends a significantly greater reliance on covered conductor deployment, as it is more cost-effective and can play a large role in driving down risk over this rate case period.[854] "Covered conductor can be deployed much more quickly and easily than undergrounding."[855] TURN proposes that over the next four years PG&E install 1,800 miles of covered conductor and 200 miles of undergrounding. If continued for ten years, such a program would result in 4,500 miles of covered conductor and 500 miles of undergrounding.[856] TURN recommends that that the Commission authorize a lower forecast for covered conductor from 2023-2026 at approximately $1.492 billion (an estimated cost of $800,000 per circuit mile in 2023) and for undergrounding from 2023-2026 at approximately $613 million.[857]

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852 TURN Opening Brief at 387; TURN Ex-11 at 20. TURN states "PG&E's disregard for the affordability of electric rates …impedes state electrification goals, which depend on the financial viability of electricity [ratepayers' ability to pay for electricity] as a fuel for building appliances and vehicles."

853 TURN Opening Brief at 387; TURN Ex-11 at 31.

854 TURN Opening Brief at 414. TURN Opening Brief at 387, fn. 1143, stating: "Ex. TURN-11, p. 45, Table 12. The cost of TURN's proposal is calculated using TURN's proposed unit cost for covered conductor. TURN's proposal would be approximately twice the cost using PG&E's unit cost for covered conductor."

855 TURN Opening Brief at 414.

856 TURN Opening Brief at 389.

857 TURN Ex-11 at 22.

Similarly, Wild Tree Foundation states that the historically high amount of time and resources PG&E must necessarily spend on undergrounding conversions are time and resources not available to implement proven wildfire mitigation strategies, in particular deployment of covered conductors.[858]

Based on the above, the Commission finds that, as compared to TURN's alternative recommendation of approximately $2.1 billion (2023-2026) and the "hybrid scenario" of approximately $4.270 billion, PG&E's capital forecast of approximately $5.9 billion plus additional expenses (2023-2026) will present challenges for customers regarding affordability and our finding weighs against adopting PG&E's proposal. The 'hybrid scenario" is more reasonable from an affordability perspective. Given the nascent stage of PG&E's undergrounding ambitions, this Commission finds that the "hybrid scenario" offers an opportunity for PG&E to prove that it can perform undergrounding projects at scale in a timely manner while achieving forecast unit cost reductions, and the "hybrid scenario" appropriately balances costs, risk reduction, timeliness, and feasibility.

4.3.6. Pace of Undergrounding as Compared to Covered Conductor

While PG&E argues that undergrounding will reduce risks in HFTDs up to 20% (2023-2026), PG&E has no historical track record of successfully undergrounding at its proposed pace. If PG&E is unable to maintain its projected pace of construction, its actual risk mitigation will decrease. PG&E acknowledges that undergrounding is a formidable task in contrast to installing covered conductor, stating that overhead system hardening "can often be done more

[858] Wild Tree Foundation Ex-01 at 4.

quickly" than undergrounding projects.[859] In weighing undergrounding versus covered conductor, PG&E does not provide a forecast of the number of miles in which it could install covered conductor during 2023-2026 if fewer resources were directed to undergrounding.

An analysis of PG&E's proposed pace of undergrounding is challenging because of the nascent stage of the program and the absence of actual historic data on feasibility of construction at the proposed scale. The Commission is skeptical of PG&E's proposed pace, and will scrutinize PG&E's progress over time. PG&E asserts that it will capture cost efficiencies at scale particularly in construction activities, which are approximately two-thirds of the undergrounding cost-per-mile.[860] For example, PG&E notes that it recently updated one of its underground design standards to reduce the depth at which cable needs to be buried from 36 inches to 30 inches in certain areas, which will reduce construction time and costs. PG&E states it is able to more quickly install covered conductor on its overhead distribution assets, which PG&E claims mitigates wildfire risks by 62% (used alone), compared to the process of undergrounding its distribution assets, which PG&E claims mitigates wildfire risk on an asset by 99%. PG&E states that the current process to deliver undergrounding work takes approximately 19-36 months and suggests PG&E will reduce this timeline to one to two years.[861] PG&E also states that "Overhead system hardening can often be done more quickly than line relocation or undergrounding, by taking advantage of existing rights and easements."[862]

[859] PG&E Ex-04 at 4.3-44.

[860] PG&E Opening Brief at 403-404.

[861] PG&E Reply Brief at 361.

[862] PG&E Ex-04 at 4.3-44.

Future GRC or other cost recovery applications will benefit from actual cost and construction data for undergrounding at a larger scale. In its next GRC, or other application seeking funding for undergrounding, PG&E shall provide the cost per mile and risk reduction it achieved in all undergrounding projects in the previous two years.

4.3.7. Accountability

No utility, including PG&E, has ever made a proposal of this magnitude for undergrounding its distribution assets. In addition, no historical operational data was presented demonstrating that PG&E has achieved this pace of undergrounding in the past. As stated by PG&E, a high level of uncertainty surrounds its forecast and PG&E's specific plans for its undergrounding program will "necessarily evolve over the life of the program as PG&E integrates lessons learned, incorporates new technologies, updates its risk modeling, and addresses stakeholder concerns. It will be both reasonable and necessary to refine and continually update the program over time."[863] Undergrounding work can face myriad challenges including difficult terrain, weather delays, permitting, land access and construction issues.

Given the uncertainty associated with large scale undergrounding, the significance of this program as a risk reduction proposal, and the significant ratepayer costs involved, we find it is prudent to require heightened tracking and reporting of costs and work to ensure accountability. The unit cost declines forecasted by PG&E in its undergrounding proposal are similarly unprecedented, and justify a conservative approach to phasing in this mitigation. This decision offers PG&E an opportunity to prove how well it can underground

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[863] PG&E Opening Brief at 412.

lines in a way that effectively reduces risk and manages costs. We will examine PG&E's progress closely, and require heightened tracking and reporting of costs to ensure transparency and accountability. We expect the information filings ordered by this decision may help inform review of any future requests made by PG&E for ratepayer funding for undergrounding, and that future forecasts of unit costs and pace of work will be informed by historic actual data. PG&E shall file an annual System Hardening Accountability Report Advice Letter with the Commission's Safety Policy Division every February 15th through the GRC period, with the final report due February 15, 2027. It shall serve the report on the service list for this GRC. The report shall include the following information on the previous year's activity with information for each completed covered conductor and undergrounding project: (1) Project Name, Location, and Tranche of each project, (2) circuit miles for each project, and (3) risk reduction achieved in each of the tranches. Attached to the report PG&E shall also include two specific spreadsheets for comparison in Excel and PDF format: (1) a "baseline" sheet for the mitigation portfolio as approved in the GRC with projected annual risk reduction amounts, and (2) a "completed" sheet for the completed projects (i.e., update "Program Exposure" and "Program Cost" tabs in the completed project spreadsheet). Risk reduction will be measured by comparing the "completed" to "baseline" sheet. In each report on annual System Hardening Accountability, PG&E shall demonstrate how much risk reduction it has achieved. PG&E shall explain its progress and the degree to which they meet or exceed reducing risk by at least 20% of the 2023 baseline risk amount. If the annual completed project risk reduction is less than the total projected risk reduction, PG&E shall submit via Advice Letter to the Safety Policy Division a revised 2023 PG&E GRC Wildfire Mitigation Spreadsheet which supports a plan on how PG&E will increase Wildfire Mitigation miles in the current year to eliminate the discrepancy in risk reduction.

Within 60 days of the final adoption of this decision, PG&E shall file an initial Advice letter with Safety Policy Division establishing the methodology for the 'baseline system' spreadsheet for the System Hardening Accountability Report. Safety Policy Division Staff are delegated authority to adjust the requirements for this report, including but not limited to adjusting the baseline and baseline sheet and selecting the version of the Wildfire Distribution Risk Model, to advance the transparency and accuracy of the reporting. In its report, PG&E shall demonstrate its progress to achieve total risk reduction amount over the GRC cycle of at least 20% of the 2023 baseline risk amount. Staff may also require adjustments to the content and format of the report to ensure accuracy and consistency with the implementation of SB 884, should PG&E choose to participate in the SB 884 program.

Spending for undergrounding and covered conductor mitigations shall be tracked through the WMBA. PG&E shall track unit cost for undergrounding and covered conductor mitigation programs annually.

We observe under the current statutory scheme in Pub. Util. Code §§ 8386.4(a) and (b), an electrical corporation, including PG&E, may establish memorandum accounts to track costs incurred to implement its Wildfire Mitigation Plan and other fire risk mitigation activities not previously covered in revenue requirement. After the Commission approved PG&E's first Wildfire Mitigation Plan in 2019, PG&E submitted an Advice Letter to establish the

Wildfire Mitigation Plan Memorandum Account (WMPMA) authorized under Section 8386.4(a).[864]

The Commission's ratification of an approved WMP does not authorize rate recovery; rather, the Commission considers the reasonableness of the costs of implementing the electrical corporation's WMP in its General Rate Case or an application for recovery of the cost of implementing the WMP as accounted in the memorandum account or otherwise. Additionally, an electrical corporation may pursue conditional approval of a 10-year undergrounding plan pursuant to Pub. Util. Code § 8388.5.

The Commission has reviewed whether additional costs incurred to implement wildfire risk mitigation above the amounts authorized for rate recovery in the GRC are just and reasonable through after-the-fact reviews. While this structure allows an electrical corporation the opportunity to collect additional revenues above and incremental to the revenue requirement authorized in a GRC, it also requires the Commission to ensure an electrical corporation does not recover additional revenue for wildfire risk mitigation activities unless those activities are incremental to the work authorized in its GRC.[865] Given the Commission's concerns with the feasibility, cost, and risk reduction associated with PG&E's proposed undergrounding program and our determinations on the reasonableness of proposed forecasted costs made today, if PG&E seeks after-the-fact cost recovery for additional wildfire costs incurred during the rate case period covered by this GRC, we will scrutinize additional costs per mile or additional miles of system hardening completed to ensure the

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[864] PG&E's WMP was approved on June 4, 2019, in D.19-05-037. On June 5, 2019, PG&E filed Advice Letter 5555-E to establish the WMPMA, which was approved on August 5, 2019.

[865] See, e.g., PG&E WMCE A.20-09-019.

resulting rates are just and reasonable. Further, should PG&E implement its plan notwithstanding the Commission's determination that certain costs associated with the plan's costs are reasonable, the Commission can scrutinize PG&E's justification for completing additional mileage.

4.3.8. Construction Feasibility of PG&E's Proposal to Underground 2,000 Miles in 2023-2026

Construction feasibility, as used here, means the ability of PG&E to meet the construction goals required to underground 2,000 miles of its infrastructure within the 2023-2026 time period. While PG&E states that its "preferred wildfire mitigation approach is undergrounding," PG&E also acknowledges it will necessarily need to rely on other wildfire mitigation activities because of a number of factors, including "construction feasibility challenges."[866]

Parties raise serious questions about the feasibility of PG&E's proposal to construct 2,000 miles of its distribution system underground. Cal Advocates states that insufficient evidence exists that PG&E can achieve the ambitious mileage target or the substantial unit cost reduction.[867] California Farm Bureau Federation states that PG&E has not proven it can realistically achieve these construction goals, suggesting that, based on the total number of miles PG&E undergrounded in 2022 of 135 miles, it is not plausible that PG&E is able to increase its performance by 439% to reach its goal of 750 miles in 2026.[868] Comcast suggests that PG&E will likely encounter shortages of construction materials, equipment, supply chain issues, and limited labor resources.[869] Wild

[866] PG&E Reply Brief at 357-358.

[867] CALPA Ex-07 at 34.

[868] California Farm Bureau Federation Sur-Reply Brief at 2.

[869] Comcast Ex-02 at 4-5.

Tree Foundation states that PG&E will not be able to scale up its undergrounding conversions at the pace it claims.[870] TURN provides an estimate based on historical data that projects PG&E's undergrounding proposal would take approximately *2,200 years*, stating that between the years 2015-2021, PG&E placed 155 miles of distribution lines underground, an average of 22 miles per year.[871] TURN suggests that, even at the quickest pace achieved, it would take PG&E over *150 years* to achieve PG&E's undergrounding proposal.[872] TURN raises a related concern stating that, should PG&E fall behind schedule, PG&E may focus its undergrounding where it can expedite construction rather than in areas most beneficial for risk reductions purposes.[873] AARP's recommendation is to postpone a decision on PG&E's undergrounding forecast until further information is available and alternatives more fully evaluated is persuasive here as PG&E's is unable to reasonably assure the Commission of the construction feasibility of its proposal and related costs.[874]

Based on the above, the Commission finds that, while PG&E may intend to underground 2,000 miles in four years, PG&E fails to establish the feasibility of its proposal to underground 2,000 miles of assets. We observe that PG&E has increased the pace of undergrounding in recent years, but at a smaller scale than its proposal would reflect. In 2022, PG&E undergrounded 180 miles, and in 2021

[870] Wild Tree Foundation Ex-01 at 5.

[871] TURN Ex-11 at 35 (based on PG&E's February 2022 proposal to underground 3,300 miles).

[872] TURN Ex-11 at 35 (based on PG&E's February 2022 proposal to underground 3,330 miles).

[873] TURN Ex-11 at 35-36.

[874] AARP Opening Brief at 26-28.

it undergrounded 73 miles. [875] We conclude that authorizing 972 miles of undergrounding in the "hybrid scenario" is an appropriate middle ground.

4.3.9. Risk-Spend Efficiency Modeling

The Commission has focused on a method for PG&E to incorporate safety risks into this overall decision-making process for more than 10 years. The Commission will not review the history of this process but notes that it started in earnest after the tragic failure of PG&E equipment in San Bruno. The Commission has developed the Risk-Spend Efficiency, or RSE, to provide a method of assessing the cost-effectiveness of various safety programs and in this instance, wildfire mitigation measures.[876]

Regarding Risk-Spend Efficiency modeling for wildfire mitigation within System Hardening, PG&E acknowledges that installing covered conductor and undergrounding have "similar RSEs" but emphasizes that in 2026, by the end of this general rate case period, the RSE for undergrounding at 5.9 will slightly exceed that of covered conductors at 5.6.[877] In short, according to PG&E, risk modeling under the RSE only presents a "minor difference" between undergrounding and use of covered conductor. Nevertheless, PG&E claims the RSE results support its decision to rely heavily on undergrounding, rather than covered conductor, emphasizing a goal of "near total elimination of ignition

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[875] PG&E 2023-2025 WMP at 3. PG&E 2023-2025 WMP Table PG&E-1.1-1: PG&E's Performance Against 2020-2022 Quantitative WMP Initiative Targets on p. 990.

[876] D.22-03-008, *Decision Closing Risk Assessment Mitigation Phase Proceeding* (March 17, 2022) at 1, stating: "PG&E filed its RAMP Report pursuant to the procedures set forth in Decision (D.) 14-12-025, D.16-08-018, and the settlement agreement adopted in D.18-12-014. The RAMP Report provides an initial quantitative and probabilistic assessment of PG&E's top 12 safety risks, plans to mitigate these risks, and estimates of costs associated with the proposed mitigations."

[877] PG&E Reply Brief at 346. Note: These are average RSEs based on PG&E figures, adding total risk reduction divided by total costs.

risk," which is only achieved via undergrounding.[878] PG&E summarizes its position regarding RSEs in its reply brief, stating "RSEs are not a significant driver of the choice between overhead [hardening] and undergrounding because the two mitigations have similar RSEs."[879]

Evidence submitted by parties supports this conclusion.

We note that the Commission has already articulated in the original Risk-Based Decision-Making OIR the need to evaluate both quantitative and qualitative benefits to proposed safety investments:

> We are interested in the scrutiny of safety and reliability programs in GRCs not only within the larger decision-making framework considering both quantitative and qualitative benefit trade-offs supporting the programs. Therefore, we expect an evolution in the way utilities identify safety and reliability risks and justify the value of investments and operations expenses in relation to how well those risks are mitigated.[880]

The Commission has adopted a risk-based decisionmaking framework, including risk reduction and risk spend efficiency analysis, to evaluate the reasonableness of competing safety-related investment proposals.

4.3.10. Telecommunications Providers Concerns Regarding Scope of Proposed Undergrounding

Telecommunications companies present concerns regarding PG&E's proposal to underground 2,000 miles of overhead assets in the absence of more information and advanced planning. Telecommunications companies place

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[878] PG&E Reply Brief at 346-347.

[879] PG&E Reply Brief at 346. Note: RSE = Risk Reduction divided by Costs. With undergrounding, the Risk Reduction is higher than covered conductor however covered conductor has lower Costs.

[880] R13-11-006 at 7.

equipment on PG&E's utility poles and these companies often have shared use agreements with PG&E for space to connect communication assets to the utility poles. AT&T and Comcast present concerns regarding the potential service and cost impact should poles no longer be a viable option for placement of telecommunication facilities. These concerns were heightened by the absence of information regarding the location of PG&E's specific construction plans. No party presents evidence of communications facilities' risk of wildfire ignition.

AT&T details the cost and complexities that PG&E's undergrounding creates for companies that rely on pole attachments, emphasizing the potential damaging impact on telecommunications services and customers.[881] AT&T states these are critical issues involving the integrity of telecommunications service that the Commission must consider when determining whether and how much wildfire-mitigation undergrounding PG&E should undertake.[882] AT&T further states that, while PG&E gives the impression of a detailed undergrounding plan, very little information is available to parties.[883] For instance, AT&T explains that to underground its facilities, "close coordination with PG&E (or its contractors) would be essential."[884] "If AT&T did underground jointly with PG&E, for instance, timing for installing facilities includes coordination on materials, local permitting, inspections and installing and burying conduit, and then returning to pull the wires through the conduit. But PG&E does not propose any process for this, or otherwise address the issue at all."[885] AT&T also raises questions about

[881] AT&T Ex-04 at 1.
[882] AT&T Ex-04 at 1.
[883] AT&T Ex-04 at 2.
[884] AT&T Ex-01 at 6.
[885] AT&T Opening Brief at 8.

how PG&E's undergrounding proposal will impact broadband deployment, stating that because of "the implications of undergrounding for broadband deployment and the proper entities to bear the costs of PG&E's proposed undergrounding initiative, the Commission should institute a rulemaking to address how the costs of any potential undergrounding of communications facilities should be funded."[886]

Communication companies assert PG&E did not adequately consider less disruptive options (or less expensive options) for wildfire mitigations.[887] Comcast states that PG&E has not provided the Commission or any stakeholder, such as Comcast, with a plan that accurately addresses and projects the costs of the undergrounding program.[888] Comcast is requesting that, for any future undergrounding projects PG&E aims to complete for wildfire mitigation, the Commission should require PG&E to leave its poles in place and allow telecommunication companies to maintain their attachments.[889]

In response, PG&E states "There is no compelling regulatory reason for PG&E to provide the specific location information in a revised plan in this GRC. The Commission is reviewing PG&E's funding request for undergrounding, not the specific undergrounding location plans. In addition, the undergrounding plans will necessarily evolve over the life of the program."[890]

While PG&E is correct that the Commission in this proceeding is primarily evaluating whether PG&E has substantiated its cost forecast, this evaluation

[886] AT&T Opening Brief at 3.

[887] AT&T Ex-04 at 2.

[888] Comcast Ex-01 at 12.

[889] Comcast Ex-01.

[890] PG&E Opening Brief at 411-412.

necessarily involves evaluating the soundness of PG&E's proposed work plans, such as undergrounding 2,000 miles of assets, and whether this proposal will have economic or service impacts on other businesses that the Commission must also take into consideration. Thus, while we do not resolve the communications providers' issues here, they may be raised as specific undergrounding proposals come to the Commission for approval.

4.3.11. System Reliability - Potentially Less Power Shutoffs Due to Overhead Infrastructure Damage and Less Reliance on PSPS/EPSS

In support of its 2,000-mile undergrounding proposal (2023-2026), PG&E states that undergrounding "reduces customer impacts due to PSPS and Enhanced Powerline Safety Settings (EPSS) programs, and improves system reliability and resiliency."[891] PG&E explains that it is committed to undergrounding 10,000 miles in and near HFTDs in order to reduce reliance on the PSPS and EPSS programs and reduce wildfire risk.[892] PG&E states that similar benefits will not result from increased use of covered conductor.[893]

TURN states that PG&E's cost forecast for PSPS and EPSS (addressed separately herein) do not reflect reduced use of these mitigations in the near future.[894] TURN emphasizes that, because the evidence fails to support undergrounding on the scale suggested by PG&E, that continued measured use of PSPS and EPSS as a mitigation is preferred over "PG&E's enormously costly

[891] PG&E Reply Brief at 351.

[892] PG&E Reply Brief at 351.

[893] PG&E Reply Brief at 347.

[894] TURN Opening Brief at 383.

and insufficiently supported undergrounding proposal."[895] Other parties generally agree with this trade-off as explained by TURN.[896]

The Commission finds that PG&E is likely correct that increased undergrounding, especially on the magnitude suggested by PG&E, will result in PG&E's decreased reliance on PSPS and EPSS, as compared to now, for purposes of wildfire mitigation. The Commission further agrees that decreased use of PSPS and EPSS will benefit ratepayers and the general public because the impacts of PSPS and EPSS on communities is significant, as these programs cut power over potentially significant periods, leaving customers with no electric service during times of the year when wildfire risk is high.

4.3.12. Lower Cost Future Technologies – Rapid Earth Fault Current Limiter (REFCL)

Lower cost technologies that are now in use could render undergrounding less attractive from a risk perspective. One such technology received attention in this proceeding, REFCL or Rapid Earth Fault Current Limiter. REFCL is installed on a substation transformer and provides line-to-ground protection for all circuits served from the substation transformer. REFCL technology uses a component called a Ground Fault Neutralizer that detects high-impedance, line-to-ground faults and limits the fault current below ignition thresholds.[897] PG&E has a short-term strategy to install REFCLs in HFTD areas. PG&E forecasts deploying REFCLs at an additional two substations each year, but these plans

[895] TURN Opening Brief at 383.

[896] MGRA Reply Brief at 13.

[897] PG&E Ex-04 at 4.3-63.

could change pending pilot results and integration with other enhanced automation and wildfire mitigation efforts.[898]

While the benefits of REFCL are not currently entirely understood, the evidence shows that REFCL illustrates the potential for new technologies to supplement risk reduction goals and minimize the usefulness of the costly option of undergrounding as the only option for near elimination of risk of wildfire caused by PG&E's overhead assets. PG&E explains as follows:

> …due to differences in PG&E's system and environmental factors, a single wildfire risk mitigation approach (e.g. combination of mitigations) would not be applicable or appropriate across the whole of PG&E's electric distribution system. Rather, it is the full complement and combination of PG&E's proposed mitigations working together, where they are each appropriately deployed, that provides the most risk reduction. As some of the technologies referenced in the question (e.g. REFCL, Early Fault Detection) as well as other tools (e.g. enhanced powerline safety settings (EPSS)) are implemented and matured PG&E will enhance our understanding of the risk mitigation value provided by each tool and how to optimally deploy them in combination with one another.[899]

According to MGRA, PG&E should be devoting sufficient resources to R&D on promising technologies such as RF Sensors, ECCVM sensors,[900] to position PG&E to rapidly be deployed at scale if R&D efforts prove feasible and

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[898] PG&E Ex-04 at 4.3-63.

[899] CALPA Ex-30 at 2.

[900] ECCVM refers to Event Classification Through Current and Voltage Monitoring sensors, which measure current and high resolution but add voltage reads for a comprehensive and synchronized power measurement of each phase from the substation outlet. PG&E Ex-04 at 4.3-56.

cost effective.[901] MGRA recommends that PG&E use additional funding and resources to allow it to accelerate R&D of its RECFL projects, and to plan initial deployment.[902] Referring to REFCL, Cal Advocates recommends that before the Commission agrees to an ambitious undergrounding plan, it require PG&E to submit a detailed analysis of emerging alternatives to undergrounding, such as REFCL technology and Cal Advocates points to a recent report on REFCL by SCE.[903]

The Commission finds that new emerging technologies, such as REFCL, may in the near future enable PG&E to reduce the risk of wildfire caused by its overhead assets at a significantly lower costs than undergrounding. Because new technologies are emerging that may be highly effective at reducing ignition risks and much less costly, these developments weigh against authorizing a $5.9 billion forecast to support an ambitious plan to underground 2,000 miles when emerging technology may soon present a more attractive alternative for ratepayers in terms of safety and costs.

4.3.13. Discussion

The Commission is charged with balancing the competing goals of the need for reliable safe service, with minimal risks of harm, and affordability. In evaluating the arguments and evidence presented on PG&E's 2023-2026 capital forecast of $6.4 billion for System Hardening, the Commission finds that the evidence and arguments summarized above weigh against approving PG&E's request and that PG&E has failed to establish by the preponderance of evidence

[901] MGRA Ex-01 at 90-91.

[902] MGRA Ex-01 at 88 and 90.

[903] CALPA Ex-07 at 12.

that its forecast for System Hardening ($5.9 billion for undergrounding and $517 million for covered conductor) is reasonable.

Instead, the Commission finds the alternative proposed capital expenditures forecast of $4.270 billion associated with the "hybrid scenario," which combines elements of proposals from PG&E and TURN, to be reasonable because it achieves a balance of risk reduction and cost containment.

To summarize the discussion above, covered conductor and undergrounding both offer unique benefits and tradeoffs as wildfire mitigation approaches. As calculated by PG&E, the RSEs by 2026 for covered conductor (5.6) and undergrounding (5.9) are likewise similar. While undergrounding an asset substantially reduces the risk of wildfire ignition (PG&E claims 99% reduction from undergrounded asset), covered conductor offers significant risk reduction (of at least 62% - with evidence of higher effectiveness pursuant to recent filings by PG&E and other utilities with the Office of Energy Infrastructure). Covered conductor projects can be completed at a faster pace with significantly less construction feasibility unknowns than undergrounding projects. Covered conductor is a proven mitigation and has been installed on thousands of miles across California. Construction feasibility is a significant concern with PG&E's 2,000-mile proposal, as unknowns around the availability of material and labor place an unreasonably high level of uncertainty around PG&E's ability to execute its plans.

Costs are a significant concern, and with PG&E's proposal at $6.4 billion, the Commission must examine alternatives to mitigate the burden to ratepayers, particularly at a time when ratepayers are experiencing unprecedented rate increases. The "hybrid scenario" presents a more reasonable cost at a time when ratepayers are experiencing unprecedented rate increase than PG&E's proposal at $6.4 billion. Moreover, while it is undisputed that undergrounding nearly eliminates the risk of ignition on an asset, the Commission does not find it reasonable to approve capital expenditures of $5.9 billion when PG&E estimates its undergrounding proposal will reduce risk up to 20% in HFTDs.

Regarding system reliability concerns suggested by PG&E, system reliability will likely improve with increased undergrounding (and decreased reliance on PSPS or EPSS) but PG&E failed to provide convincing evidence that it can achieve its ambitious construction goals on the proposed timeline of four years which is required to achieve increased system reliability. Failure to place assets underground would mean continued reliance on PSPS and EPSS (in addition to the higher wildfire risk presented by bare overhead wire). At the same time, the impact of aggressive installation of covered conductor, increased maintenance, and new technologies, such as REFCL/Rapid Earth Fault Current Limiter, could similarly decrease reliance on PSPS and EPSS. The unknown impact of undergrounding on telecommunications services, broadband deployment, and allocation of cost for any remaining poles needs to be better understood before the Commission supports larger-scale undergrounding of assets used by these companies.

Overall, based on the significant unknowns and unaddressed concerns regarding PG&E's ability to successfully implement its proposal in a timely manner together with the steep costs, the Commission finds that PG&E's $6.4 billion forecast for System Hardening (undergrounding and covered conductor) is unreasonable at this point in time.

Instead, the Commission approves a System Hardening forecast consistent with the "Hybrid Scenario." This scenario, reducing more wildfire risk at a lower cost with fewer feasibility and timeline risks, is a superior option at this time.

Accordingly, the Commission adopts a 2023-2026 cost forecast of $4.270 billion for capital expenditures for System Hardening, which consists of a forecast of $1.369 billion for overhead hardening and a forecast of $2.901 billion for undergrounding. The $1.369 billion of capital expenditures for overhead hardening are as follows: $323,827,628 (2023); $338,161,874 (2024); $348,165,802 (2025); and $358,469,922 (2026).[904] The $2.901 billion of capital expenditures for undergrounding are as follows: $488,157,244 (2023); $630,577,194 (2024); $760,910,771 (2025); and $1,021,075,674 (2026).[905]

Regarding PG&E's expense forecast for System Hardening, the Commission finds reasonable the uncontested 2023 expenses forecast for System Hardening of $11.595 million.

4.4. Other Wildfire Risk Mitigations

The activities comprising of PG&E's Other Wildfire Risk Mitigations include: (1) Situational Awareness and Forecasting; (2) PSPS Operations; (3) Enhanced Automation and PSPS Impact Mitigations; (4) Information Technology for Wildfire Mitigation; and (5) Enhanced Powerline Safety Settings (EPSS).[906] On February 25, 2022, PG&E revised its wildfire mitigation strategy by adding EPSS, "prioritizing system hardening undergrounding," and "revising the scope of Enhanced VM."[907] The Commission addresses PG&E's forecast for its revised wildfire mitigation strategy within Other Wildfire Risk Mitigations and PG&E's plans to rely on EPSS during its undergrounding construction, below. Notably, during this construction period, PG&E explains that EPSS

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904 TURN Ex-11 at 28.

905 TURN Ex-11 at 30.

906 PG&E Reply Brief at 375.

907 PG&E Ex-04 at 4.1.

remains an important wildfire mitigation measure because its electric lines continue to be bare so the risk of ignition remains undiminished.[908]

Cal Advocates, TURN, and MGRA oppose certain portions of PG&E's forecasts within Other Wildfire Mitigations, including PG&E's forecasts for PSPS Operations; Enhanced Automation and PSPS Impact Mitigations; and EPSS.[909] PG&E states that it records the expense and capital expenditures for all the activities related to Other Risk Wildfire Mitigations in the balancing account referred to as the WMBA.[910] The Commission addresses each of these wildfire mitigation forecasts below.

[908] PG&E Ex-17 (Rebuttal) at 3-27, stating "PG&E's comprehensive wildfire mitigation strategy focuses on increasing the number of miles and pace of undergrounding, expanding the EPSS program, and adjusting the scope of Enhanced Vegetation Management."

[909] PG&E Reply Brief at 375.

[910] The Commission created the WMBA in D.20-12-005 (PG&E TY 2020 GRC). In PG&E Ex-04 at 2-17, PG&E states that wildfire mitigations not eligible for recovery in WMBA are recorded in WMPMA if approved as part of WMP (e.g., wildfire safety inspection program and related repairs and replacement). PG&E will record wildfire mitigations into the WMPMA once it exceeds the cap for WMBA (PG&E Ex-04 at 4-25). In D.19-05-037 (PG&E 2019 WMP) at OPs 21-22, the Commission recognizes that PG&E may rely on two memorandum accounts for these costs, the WMPMA and the FRMMA, stating as follows: "OP 21. Pacific Gas and Electric Company may open the memorandum account described in Public Utilities Code Section 8386(e), which provides: 'At the time it approves each plan, the commission shall authorize the utility to establish a memorandum account to track costs incurred to implement the plan.' OP 22. Pacific Gas and Electric Company may not seek or obtain double recovery of the costs tracked in the Section 8386(e) account authorized in the previous paragraph, and the costs tracked in the memorandum account described in Public Utilities Code Section 8386(j), which the utility established with Energy Division's approval. The Section 8386(j) account is described in Senate Bill 901 as follows: '(j) Each electrical corporation shall establish a memorandum account to track costs incurred for fire risk mitigation that are not otherwise covered in the electrical corporation's revenue requirements.'" *See also*, CPUC Resolution WSD-03 OP 7; CPUC Resolution WSD-021 OP 11; CPUC Resolution SPD-09.

4.4.1. Situational Awareness and Forecasting

PG&E's 2023 expense forecast is $43.416 million.[911] The expense forecast includes work tracked in MWC AB Miscellaneous Expense.[912] PG&E's capital expenditures forecast is $9.451 million in 2021, $9.375 million in 2022, and $4.601 million in 2023. [913] The capital forecast includes work tracked in MWC 21 Miscellaneous Capital.[914] PG&E's 2020 recorded adjusted expense is $141.178 million.[915] PG&E did not modify its request regarding Situational Awareness and Forecasting in its February 25, 2022 revised wildfire mitigation strategy or its reply brief.[916] PG&E states that it tracks the expense and capital expenditures related to these activities in the WMBA. PG&E's expense and capital requests are undisputed. The Commission finds reasonable PG&E's uncontested 2023 Situational Awareness and Forecasting expense forecast of $43.416 million (MWC AB) and capital expenditures forecast of $9.451 million in 2021, $9.375 million in 2022, and $4.601 million in 2023 (MWC 21).

4.4.2. Public Safety Power Shutoff Operations

PG&E's 2023 expense forecast for PSPS Operations is $115.266 million.[917] PG&E did not modify this forecast in its February 25, 2022 proposal or its reply brief.[918] PG&E's recorded 2020 expense is $141.178 million.[919]

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[911] PG&E Opening Brief at 429, *citing to* PG&E-17 (Rebuttal) at 2-4 (Table 2-1).

[912] PG&E Opening Brief at 429.

[913] PG&E Opening Brief at 429P, *citing to* PG&E-17 (Rebuttal) at 2-5 to 2-7.

[914] PG&E Opening Brief at 429.

[915] PG&E Ex-17 (Rebuttal) at 4-12.

[916] PG&E Reply Brief at 375.

[917] PG&E Opening Brief at 430.

[918] PG&E Reply Brief at 376, *citing to* PG&E-17 (Rebuttal) at 4.2-3.

[919] PG&E Ex-17 (Rebuttal) at 4-13. (Table 4.5).

PG&E's capital expenditure request is $3.084 million in 2021, $3.237 million in 2022, $262,000 in 2023, $269,000 in 2024, $277,000 in 2025, and $284,000 in 2026.[920] PG&E states that it records the expense and capital expenditures related to these activities in the WMBA. PG&E explains that this expense forecast includes work tracked in MWC AB and capital expenditures are tracked in MWC 21.[921] PG&E also explains that the reduction in costs during this rate case period are, in part, driven by PG&E moving certain PSPS costs to Emergency Preparedness and Response (also referred to as EP&R) beginning in 2023.[922] PG&E's PSPS Operations forecast was based on PG&E's calculation of the average cost per PSPS event recorded during 2019 and 2020, multiplied by a forecasted three annual PSPS events plus an additional potential/borderline event per year.[923]

In support of its forecast, PG&E acknowledges it used improved scoping techniques and PSPS mitigation strategies (e.g., remote grid) to reduce the number of customers impacted by PSPS events in 2020 but also states it is now including additional factors in its PSPS decision-making model, including, among other factors, an update of studies for 2011-2020 weather data that "may drive an expansion of PSPS events and associated costs in future years."[924] PG&E

[920] PG&E Ex-17 (Rebuttal) at 2-5 to 2-10.

[921] PG&E Opening Brief at 430; PG&E Ex-17 (Rebuttal) at 4.2-6.

[922] PG&E Ex-04 at 5-1 to 5-3; PG&E Ex-04 at 5-7, stating "Beginning in 2023, certain wildfire mitigations will transition away from the organizations responsible for managing PG&E's wildfire mitigations and move to EP&R. These activities will be converted from wildfire-specific mitigations tracked in the WMBA and will become all hazards controls. Mitigations that are moving out of the WMBA are shown in Chapters 4.1 and 4.2 of this exhibit through 2022 and are then listed as controls in Chapter 5 starting in 2023."

[923] PG&E Opening Brief at 431.

[924] PG&E Ex-17 (Rebuttal) at 4.2-8; PG&E Opening Brief at 432.

also explains that the majority of PSPS event costs are for inspecting power lines following the end of the weather event and clarifies that costs prior to or during PSPS events are not significant drivers of projected costs.[925] In terms of justifying PG&E's method of calculating costs, basing the amount of the forecast on the number of forecasted PSPS events, PG&E states that forecasting costs for PSPS events is inherently difficult because the main driver of PSPS is weather conditions, which are unpredictable. [926]

Both Cal Advocates and TURN recommend reductions to the 2023 expense forecast on the basis that PG&E's expense forecast is inflated because the number of PSPS events implemented by PG&E in 2019, which was also the first year of PSPS recorded costs, should be viewed as anomalous and removed from the average cost because PG&E has acted to greatly limit the number and scope of PSPS events since 2019.[927] TURN and Cal Advocates state that this forecast is inflated because it is partially based on PG&E's overuse of PSPS in 2019 and, as a result, is excessive and even encourages PG&E to use PSPS even though the Commission's policy is to minimize the use of PSPS.[928] TURN recommends an expense reduction of approximately $31 million.[929] Cal Advocates recommends an expense reduction to PSPS Operations of approximately $66 million and a capital expenditure reduction of approximately $79 million in 2022 (PSPS Field Operations Tech).[930] Cal Advocates also supports it recommendation with

[925] PG&E Opening Brief at 433.

[926] PG&E Opening Brief at 433-434.

[927] Cal Advocates Opening Brief at 168.

[928] TURN Opening Brief at 422-423.

[929] TURN Ex-11 at 55.

[930] CALPA Ex-07 at 3; Cal Advocates Opening Brief at 171; PG&E Ex-17 (Rebuttal) at 2-5.

evidence that PG&E's PSPS events are decreasing in number, duration, and scope.[931] Cal Advocates adds that PG&E fails to account for the decreased need to rely on PSPS due to ongoing system hardening, such as PG&E's undergrounding plan or installation of covered conductor, and vegetation management.

The Commission agrees that 2019 was an anomalous year for costs related to PSPS Operations because 2019 was the first year PG&E relied upon PSPS as a wildfire mitigation strategy and, during 2019, PG&E built the operational foundation to support turning off power for wildfire risk mitigation. The scope and duration of PG&E's activities to support PSPS Operations in 2019 and the high number of PSPS events in 2019 should not be repeated in the forecast years because the program is now created and PG&E has taken steps to minimize its use of PSPS, seeking to ensure PSPS events are narrowly tailored and short in duration. The Commission also agrees that extreme weather makes this forecasting challenging. Accordingly, rather than adopt the larger expense reduction recommended by Cal Advocates, the Commission adopts TURN's recommended expense reduction of $31 million. The Commission also adopts a lower forecast because PG&E did not present a reduced forecast in its February 28, 2022 revised wildfire mitigation strategy to reflect incorporation of EPSS as a wildfire mitigation measure. PG&E states that "[b]uilding and expanding PG&E's electric distribution system underground will not only help eliminate wildfires caused by overhead equipment failures, but it will also help to reduce the need for and/or frequency of PSPS outages and Enhanced Powerline Safety Settings (EPSS), improving system reliability under the full

[931] Cal Advocates Opening Brief at 168 and 171.

range of weather and fire risk conditions" but provides no costs reductions to PSPS expense to reflect integration of this additional wildfire mitigation measure.[932]

For these reasons, the Commission finds reasonable TURN's recommended reduction of $31 million to PG&E's 2023 expense forecast and adopts a 2023 expense forecast of $83.798 million for PSPS Operations (MWC AB).

Regarding PG&E's capital expenditure request for PSPS Operations, the Commission finds PG&E's request reasonable within the context of the rapid initiation of this newer mitigation measure. PG&E's decreasing trend for capital expenditures reflects PG&E's relatively recent reliance on PSPS, which resulted in higher initial expenditures. Further, PG&E's forecasted decrease in capital expenditures is also reasonable since the majority of the capital assets needed for this mitigation measure have been put into place. Accordingly, the Commission adopts capital expenditures of $3.084 million in 2021, $3.237 million in 2022, and $262,000 in 2023 (MWC 21).

4.4.3. Enhanced Automation and PSPS Impact Mitigation

PG&E's Enhanced Automation work involves the use of electric technologies, mostly various sensors, to reduce the possibility of ignition caused by PG&E assets, including the following: (1) single phase reclosers with the capability to trip all phases (i.e., open all phases), eliminating the risk associated with wire down events; (2) distribution grid sensors that detect non-equipment failure types that cannot be detected by existing detection methods or patrol techniques; (3) technology that can decrease overall wildfire ignition risk by

932 PG&E Ex-04 at 4.3-8.

detecting early stage equipment failure, enabling PG&E to conduct repairs before infrastructure fails; (4) technology that mitigates ignitions from line to ground faults such as wire down or tree contacts; and (5) technologies that detect an object approaching an energized power line and respond quickly to shut off power before the object impacts the line.[933] PG&E also includes in this request equipment programs for mitigating the impacts of PSPS on customers, such as installation of sectionalizing devices and support for Temporary Generation programs that support temporary microgrids.[934]

PG&E's 2023 expense forecast is $11.595 million and is uncontested.[935] PG&E's capital expenditures forecast is $104.351 million in 2021, $92.542 million in 2022, and $81.116 million in 2023.[936] PG&E did not revise this forecast in its February 28, 2022 revised wildfire mitigation strategy or its reply brief. PG&E states that it records these costs in the WMBA. PG&E's capital forecast consists of three Major Work Categories: (1) MWC 21 Miscellaneous Capital, (2) MWC 2A Electric Distribution Install/Replace Overhead Assets, and (3) MWC 49 Distribution Circuit/Zone Reliability.[937] Two areas of PG&E's capital forecast are contested: the costs tracked in MAT 2AP Expulsion Fuse Replacement and MAT 49I Distribution Grid Sensors.[938]

Regarding the MAT 2AP Expulsion Fuse Replacement, PG&E's forecast includes work to replace non-exempt expulsion fuses, which PG&E describes as

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[933] PG&E Opening Brief at 436-437, *citing to* PG&E Ex-04 at 4.3-2.

[934] PG&E Opening Brief at 437.

[935] PG&E Opening Brief at 437, *citing to* PG&E Ex-17 (Rebuttal) at 4.3-3.

[936] PG&E Opening Brief at 437.

[937] PG&E Opening Brief at 437.

[938] PG&E Opening Brief at 438.

equipment that may "generate electrical arcs, sparks, or hot material during its normal operation … [that] could cause an ignition."[939] PG&E's capital forecast for MAT 2AP Expulsion Fuse Replacement is $15.125 million in 2021, $15.388 million in 2022, and $15.752 million in 2023.[940] PG&E's 2020 recorded capital expenditure is $7.847 million.[941] Cal Advocates recommends using PG&E's actual recorded 2021 costs (rather than the forecast) and adjusting PG&E's 2022 and 2023 capital requests, accordingly.[942] Cal Advocates then suggests using the forecasted number of installed units as a multiplier.[943] As part of Cal Advocates' analysis, it concluded that the unit cost for the fuse replacement is $6,095, while PG&E relies on a unit cost of between $12,604 to $13,281.[944] Using this reduced unit value, Cal Advocates recommends a forecast of $8.7 million in 2021, $7.3 million in 2022, and $7.2 million in 2023 for MAT 2AP Expulsion Fuse Replacement Program.[945] The Commission finds PG&E's forecast reasonable, but based on Cal Advocates' recommendation that the unit cost is actually much lower using recent 2021 data, PG&E shall provide actual and forecasted unit costs information for 2021 through 2026 in its 2027 GRC filing and provide an explanation for any dollar amount difference between PG&E's forecasted unit cost in this proceeding and the actual 2021 costs.

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[939] PG&E Opening Brief at 438.

[940] PG&E Ex-17 (Rebuttal) at 4.3-17.

[941] PG&E Ex-17 (Rebuttal) at 4.3-17.

[942] CALPA Ex-07 at 10-11.

[943] CALPA Ex-07 at 10-11.

[944] CALPA Ex-07 at 17.

[945] Cal Advocates Opening Brief at 174.

Regarding MAT 49I Distribution Grid Sensors, PG&E states that this program includes a number of different sensors that detect non-equipment failure types that cannot be detected by existing detection methods or patrol techniques.[946] These sensor technologies also detect other power flow anomalies/disruptions that may be indicative of incipient faults, which can result in ignitions.[947] PG&E's MAT 49I Distribution Grid Sensor request for capital expenditures is $12.369 million in 2021, $23.036 million in 2022, and $22.653 million in 2023.[948] PG&E does not present an expense forecast for Distribution Grid Sensors.[949] PG&E explains that it will conduct Information Technology work in 2022 and 2023 that it did not perform in 2021.[950]

Cal Advocates and MGRA present lower forecasts. Cal Advocates states that based on its analysis of 2021 recorded capital, PG&E's actual unit cost is significantly lower than the unit cost supposedly used by PG&E for forecasting purposes in this proceeding.[951] According to Cal Advocates' analysis, PG&E actually only spent $3.2 million in 2021, rather than PG&E's presented amount of $12.4 million.[952] Cal Advocates makes the argument based on its calculation of lower unit costs regarding a number of different sensors. Cal Advocates relies on data provide by PG&E in March 2022, about six months after PG&E filed its June 30, 2021 Application. For instance, for certain sensors, Cal Advocates

[946] PG&E Ex-17 (Rebuttal) at 4.3-54.

[947] PG&E Ex-17 (Rebuttal) at 4.3-54.

[948] PG&E Opening Brief at 440.

[949] PG&E Ex-17 (Rebuttal) at 4.3-72.

[950] PG&E Opening Brief at 441.

[951] CALPA Ex-07 at 20.

[952] CALPA Ex-07 at 20, *citing to* PG&E Ex-04 at 4.3-32.

suggests that, based on its analysis, the unit cost was approximately $3,556 per unit in 2021, which is much lower than the unit cost that PG&E appears to have used to calculate its forecast for 2022 and 2023.[953] Cal Advocates also raises a potential product defect issue, that PG&E apparently is currently seeking to resolve, regarding equipment replaced in 2021 that needs to be replaced again due to potential defects.[954] Cal Advocates recommends that PG&E be required to provide customer refunds when and if it receives reimbursement from the vendor.[955] Cal Advocates explains that PG&E provided little information on the status of this equipment, with PG&E stating that "PG&E's privileged investigation into the product issues is ongoing, and PG&E is still evaluating available remedies."[956]

The Commission finds PG&E's capital expenditure request of $12.369 million in 2021, $23.036 million in 2022, and $22.653 million in 2023 for MAT 49I Distribution Grid Sensors reasonable based on its projected work and forecasting method. In response to Cal Advocates' concern about the costs of the potentially defective sensors, PG&E agrees to credit the WMBA with any amounts received from the manufacturer.[957] PG&E is directed to discuss the status of this credit in the 2027 GRC together with the status of resolving this matter with the manufacturer. In addition, given the disputes between Cal Advocates on the sensor unit costs, PG&E shall provide actual and forecasted unit costs information for 2021 through 2026 in its 2027 GRC filing with an

[953] CALPA Ex-07 at 20.

[954] CALPA Ex-07 at 20-21.

[955] CALPA Ex-07 at 20-21.

[956] CALPA Ex-07 at 21-22.

[957] PG&E Opening Brief at 441.

explanation for any dollar amount differences between PG&E's forecasted unit cost in this proceeding and the actual 2021 costs.

4.4.4. Community Wildfire Safety Program Project Management

PG&E presents its 2023 expense forecast of approximately $13.5 million regarding the Community Wildfire Safety Program Project Management Organization (also referred to as CWSP PMO).[958] PG&E did not modify this forecast in its February 25, 2022 revised wildfire mitigation strategy or its reply brief. PG&E states that it records these costs in the WMBA. Regarding its Community Wildfire Safety Program, PG&E states that "CWSP delivers on key facets of the PG&E's WMP [Wildfire Mitigation Plan]."[959] PG&E states that the CWSP PMO "leads and facilitates the overall CWSP, including developing and optimizing mitigation programs in conjunction with numerous other teams, facilitating the development of PG&E's annual Wildfire Mitigation Plan filing," and coordinating implantation of mitigation activities across all lines of business.[960] No party contested this request. The Commission finds the expense forecast for Community Wildfire Safety Program Project Management Organization reasonable as presented by PG&E of approximately $13.5 million for 2023.

4.4.5. Information Technology for Wildfire Mitigations

PG&E's 2023 expense forecast for Information Technology for Wildfire Mitigations is $35.700 million and this expense forecast is undisputed.[961] PG&E's

[958] PG&E Ex-64 (JCE) Vol. 1, 4-35 at 2-227.

[959] PG&E Ex-04 at 4.4-1.

[960] PG&E Ex-64 (JCE), Vol. 1, 4-35 at 2-227.

[961] PG&E Opening Brief at 441.

2023 expense forecast is reflected in MWC IG Manage Various Balancing Account Processes.[962] PG&E presents recorded costs in MWC AB Miscellaneous Expense, and MWC JV Maintain IT Applications and Infrastructure.[963] PG&E's capital expenditures request is $25.300 million in 2021, $25.300 million in 2022, and $25.300 million in 2023.[964] PG&E's capital work is tracked in MWC 2F Build IT Applications and Infrastructure. PG&E's capital forecast is undisputed. PG&E states that it records costs for Information Technology for Wildfire Mitigations in the WMBA. The Commission finds PG&E's undisputed requests reasonable regarding Information Technology for Wildfire Mitigations of a 2023 expense forecast of $35.700 million and capital expenditures of $25.300 million in 2021, $25.300 million in 2022, and $25.300 million in 2023.

4.4.6. Enhanced Powerline Safety Settings

PG&E's EPSS program consists of adjusting PG&E's overhead powerline protective device settings to be more sensitive, thereby reducing the risk of an ignition from overhead powerline faults.[965] PG&E initiated its EPSS program in July 2021.[966] PG&E explains that because this July 2021 initiation date fell after it filed its June 30, 2021 Application, PG&E's initial Application did not include a forecast for EPSS. PG&E incorporated the request for costs associated with EPSS in its February 25, 2022 revised wildfire mitigation strategy. PG&E did not

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962 PG&E Ex-04, WP 4-10; PG&E Opening Brief at 441.

963 PG&E Ex-04, WP 4-10; PG&E Opening Brief at 441.

964 PG&E Opening Brief at 442, *citing to* PG&E Ex-17 (Rebuttal) at 2-5 to 2-7.

965 PG&E Ex-04 at 4.6-9.

966 PG&E Ex-04 at 3-6 to 3-7 (fn. omitted); PG&E Ex-04 at 4.6-6 to 4.6-7. PG&E implements EPSS by adjusting system protective devices (line reclosers and substation circuit breaker protective relays) to make the devices more sensitive and able to react to a fault more quickly, thus reducing the magnitude of the current supplied to a fault. In this manner, PG&E seeks to reduce the risk of ignitions from sparks due to faults on its electrical lines.

modify this proposal in its December 9, 2022 reply brief. Regarding EPSS, PG&E explains that its costs are based on enablement of EPSS on 170 circuits in 2021 and 988 circuits (11,500 miles of circuits) in 2022 with escalation for increased work in 2023.[967] PG&E states that its EPSS forecast also includes funding for activities that respond to and/or decrease the effect of outages on EPSS-enabled circuits as well as customer support activities.[968]

PG&E requests a 2023 expense forecast of $151.129 million.[969] PG&E explains that its 2020 recorded expense related to EPSS were $0 because this program did not exist in 2020.[970] PG&E also explains that, while it requests a forecast of $151.129 million in 2023, some of its expected expenses, such as MAT FZE for field circuit setting work, are not included in its forecast because "PG&E has not yet determined the scope of that work or estimated its costs."[971] PG&E states it will record incurred expense for MAT FZE Reprogram Devices and Engineering and seek recovery through the WMBA due to undetermined scope and costs. [972]

PG&E requested no capital expenditures for EPSS and explains that such costs will be incurred but are too uncertain to forecast presently.[973] PG&E explains that, while it is unable to presently forecast its capital costs for EPSS, it

[967] PG&E Ex-04 at 4.6-15; PG&E Ex-04 at WP 4-155.

[968] PG&E Ex-04 at 4.6-6 to 4.6-7.

[969] PG&E Ex-04 at 4.6-4 through 4.6-5.

[970] PG&E Ex-04 at 4.6-5.

[971] PG&E Ex-04 at 4.6-13.

[972] PG&E Ex-04 at 4.6-12 to 4.6-13. EPSS is reflected in Expense MATs BAF, BAH, BHE, FZA, GC2 and MAT IG#. Because PG&E presents no forecast for capital expenditures, no MATs for capital are presented.

[973] PG&E Ex-04 at 4.6-20.

will track incurred capital costs in the WMBA during 2023-2026.[974] Presumably, PG&E intends to seek recovery of any capital cost tracked in the WMBA but this process is unclear based on a $0 forecast.

As previously explained, PG&E's February 25, 2022, revised wildfire mitigation strategy presented significant changes to certain aspects of its wildfire mitigation forecasts. PG&E increased its forecasts related to its undergrounding proposal to reflect an initial plan of undergrounding 182 miles (June 30, 2021) to over 3,000 miles on February 25, 2022 (later decreased to approximately 2,000 miles). PG&E describes the relationship between its newly introduced forecast for EPSS, its increased forecast for undergrounding, and its decreased forecast for Enhanced Vegetation Management, as follows:

> To address the continuously evolving wildfire risk, PG&E implemented the EPSS program in July 2021 on approximately 11,500 miles of [overhead] distribution circuits, or 45 percent of the circuit miles in HFTD areas. With EPSS, if an object such as vegetation contacts a distribution line, power is automatically shut off within 1/10th of a second, reducing the potential for an ignition. In 2021, this program reduced CPUC-reportable ignitions from electrical equipment on EPSS enabled circuits by 80 percent compared to a three-year average. PG&E will expand EPSS to all circuits within the 1 HFTD and High Fire Risk Areas (HFRA), as well as some circuits within Tier 1 buffer zones in 2022.… However, it is also disruptive to customers. PG&E is actively exploring ways to reduce customer disruptions. PG&E envisions EPSS as part of an integrated wildfire risk mitigation solution that will protect against vegetation and other ignition causes while undergrounding work progresses and as the scope of EVM [Enhanced Vegetation Management] is reduced.[975]

[974] PG&E Ex-04 at 4.6-20.

[975] PG&E Ex-04 at 3-6 to 3-7 (fn. omitted).

As explained above, as PG&E increases its reliance on EPSS, it plans to reduce reliance on vegetation management. PG&E's statement that "the scope of EVM [Enhanced Vegetation Management] is reduced" reflects PG&E's reduced 2023-2026 expense forecast for its total Vegetation Management program by approximately $1 billion, from $4.977 billion on June 30, 2021 to $3.975 billion on February 25, 2022.[976] This reduction reflects changes to vegetation management. PG&E's reduced forecast reflects less vegetation management work and increased use of EPSS "commensurate with the amount of undergrounding miles completed."[977] As PG&E suggests, reliance on EPSS will decrease with progress on undergrounding, stating: "Incorporating PSPS and EPSS will further reduce wildfire risk, resulting in an overall risk reduction of approximately 93 percent" and "reliance on EPSS and PSPS will have an impact on system reliability, but it will decrease over time as the line miles underground increase."[978] However, the connection between the PG&E's forecast for EPSS and undergrounding remains unclear because, PG&E's December 9, 2022 reply brief decreased forecasted progress on undergrounding miles but did not include a commensurate increase in EPSS costs.

MGRA recommends the EPSS program be funded as a less costly alternative to undergrounding and to ensure that sufficient staff are available to reduce restoration times, which is a major concern of MGRA regarding PG&E's power shut offs for wildfire mitigation.[979] Cal Advocates asserts that the Commission should adopt its risk-informed recommendations before approving

[976] PG&E Ex-04 at 9-4.

[977] PG&E Ex-04 at 2-3.

[978] PG&E Ex-04 at 3-3.

[979] MGRA Ex-01 at 90.

any EPSS-related requests.[980] TURN presents an alternative lower forecast for PG&E's expense forecast for EPSS, as illustrated, below:

Table 4-F:
Enhanced Powerline Safety Settings (EPSS) Total Expense ($1,000)[981]

Program	2020 Recorded	2021 Recorded	Party	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
EPSS Program Total	-	$18.203	PG&E	-	$148,921	$151.129	$146.302	$140.825	$133.710
			TURN	-	-	$87.049	-	-	-

TURN disputes the cost forecast for the Additional Patrols work category within EPSS.[982] TURN alleges that the methodology relied upon by PG&E to forecast Additional Patrols costs is flawed because it is based on recorded costs per circuit, when it should be based on recorded costs per circuit mile to reflect the fact that circuits vary tremendously in length.[983] TURN's cost estimate was based on PG&E's total recorded cost for this work category in 2021 divided by the 11,500 circuit miles of EPSS-enabled circuits, the result of which was then multiplied by the forecasted total circuit mileage in the test year (44,000 miles).[984] This resulted in TURN's cost forecast of $48.430 million in 2023, compared with PG&E's cost forecast of $112.510 million.[985] TURN does not contest the other cost elements of PG&E's EPSS expense forecast.[986] TURN also supports PG&E's Fixed Power Solution pilot, though it notes that this program should be targeted as

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[980] Cal Advocates Opening Brief at 157- 158.

[981] PG&E Ex-04 at 4.6-21 (Table 4.6-7).

[982] TURN Ex-11 at 49

[983] TURN Ex-11 at 49 to 50.

[984] TURN Ex-11 at 50 to 51.

[985] TURN Ex-11 at 51.

[986] TURN Ex-11 at 50.

much as possible to Medical Baseline and Medical Baseline-eligible customers.[987] TURN states that PG&E has not demonstrated that extensive reliance on EPSS is reasonable and believes that approving PG&E's forecast could lead to an overreliance on EPSS as a wildfire mitigation measure.[988] TURN asserts that the Commission should not adopt PG&E's forecast because the utility failed to forecast costs with specificity and failed to ensure only limited customer reliability impacts. TURN argues that its own forecast is reasonable because it better reflects the variation in circuit length and allows for an expansion of the technology without encouraging overreliance on a mitigation with major customer reliability impacts.[989]

While differences exist between PG&E's PSPS and EPSS, EPSS has similar negative impacts on customers as PSPS. Regarding PG&E's requests for costs pertaining to EPSS, the Commission agrees with TURN and finds that PG&E fails to provide sufficient specificity regarding its EPSS 2023 expense forecast. The Commission also agrees that TURN's methodology for calculating an expense forecast is more accurate and finds that a per circuit mile cost is more appropriate than a per circuit cost because circuits vary in length, meaning the

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[987] TURN Ex-11 at 50. In PG&E Ex-04 at 4.6-18, PG&E presents 2023 expense forecast of ~$12 million in "financial incentives" for back-up power for EPSS for Fixed Power Solutions pilot: "PG&E plans to introduce a new permanent backup power offering, the Fixed Power Solutions (FPS) pilot program, for our most vulnerable customers, critical facilities, and schools. PG&E will provide financial incentives to residential customers that help reduce the cost of permanent solar and storage installations. PG&E plans to focus the residential FPS offering on MBL, low-income, rental, and other customers located in HFTD areas who face financial barriers to installing expensive permanent backup power solutions. The non-residential portion of the FPS pilot will offer technical assistance and financial incentives to help reduce the cost of equipment installations, which will help reduce the number of critical facilities and schools that are negatively impacted by EPSS."

[988] TURN Opening Brief at 428.

[989] TURN Opening Brief at 431.

time and cost of patrolling the circuit post-EPSS is not uniform for each circuit.[990] Regarding PG&E's capital expenditure forecast of $0, the Commission agrees with TURN and is concerned that PG&E's unspecified 2023 capital forecast may signal a potential for overreliance on this mitigation measure, especially because PG&E presents a $0 capital forecast while implying it expects to incur costs, expects to recorded costs in the WMBA, and expects to seek approval of those costs later. PG&E's attempts to justify its capital request of $0 due to uncertainty with EPSS and because PG&E only started to rely upon this technology in July 2021. At the same time, PG&E is confident that EPSS will reduce risk of ignition and PG&E has already initiated this mitigation measure on approximately 11,500 miles of circuits in 2023. PG&E's position that too much uncertainty exists to present a capital forecast is not persuasive. If PG&E had sufficient information to support its expense forecast, PG&E should be able to present a capital expenditure forecast.

Overall, the Commission finds that PG&E fails to support a persuasive 2023 forecast for expense and a reasonable explanation for the absence of a forecast for capital expenditures. Accordingly, regarding expense, the Commission adopts TURN's recommendation to reduce PG&E's EPSS 2023 expense forecast to $87.049 million. Regarding capital expenditures, the Commission adopts PG&E's EPSS forecast for capital expenditures of $0 but the Commission expects PG&E to continue to refine EPSS program implementation and pursue opportunities to use new technologies and efficiencies to narrowly tailor its EPSS program and improve restoration times. As TURN highlights, the Independent Safety Monitor recently noted that PG&E has reduced its response

[990] TURN Opening Brief at 428.

time to EPSS outages significantly, and, as such, the duration of each EPSS events should decrease going forward.[991] The Commission will continue to closely monitor response time and duration of EPSS with the expectation of continued improvements.

4.5. Emergency Preparedness and Response

PG&E states that Emergency Preparedness and Response funding supports work needed to prepare and plan for responding to emergency events by having integrated plans and appropriate facilities, logistics, technology, and processes in place prior to an event occurring.[992] In particular, PG&E states the funding for Emergency Preparedness and Response enables PG&E to be able to identify risks and hazards across the threat landscape, develop plans, and train and exercise their response to effectively coordinate emergency response efforts among PG&E's various lines of businesses and collaborate with external governmental emergency response agencies.[993]

PG&E's 2023 expense forecast for Emergency Preparedness and Response is $29.557 million.[994] The expense forecast includes work tracked in MWC AB Miscellaneous Expense.[995] PG&E's capital expenditures forecast for Emergency Preparedness and Response is $2.109 million in 2021, $2.143 million for 2022, $6.477 million for 2023, $6.458 million in 2024, $6.472 million in 2025, and $6.561 million in 2026. PG&E's capital work is tracked in MWC 21 EP&R Capital.

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991 TURN Opening Brief at 382.

992 PG&E Opening Brief at 445.

993 PG&E Opening Brief at 445.

994 PG&E Opening Brief at 445. (Includes escalation adjustment reflected in the September 6, 2022 Update Testimony at PG&E Ex-33.)

995 PG&E Opening Brief at 445.

No party disputes PG&E's expense or capital forecast.[996] The Commission finds reasonable PG&E's uncontested expense forecast of $29.557 million.[997]

The Commission finds reasonable PG&E's uncontested capital expenditure requests of $2.109 million in 2021, $2.143 million for 2022, and $6.477 million for 2023. The Commission adopts these amounts.

4.6. Electric Emergency Recovery

PG&E's 2023 expense forecast for Electric Emergency Recovery is $149.216.[998] PG&E's capital expenditures request is $277.941 million for 2021, $339.418 million for 2022, $360.523 million for 2023, $383.822 million in 2024, $395.986 million in 2025, and $398.355 million in 2026.[999]

PG&E states that Electric Emergency Recovery is necessary to: (1) respond to incidents and outages during routine and major emergencies; (2) perform equipment repairs and replacements related to routine and major emergencies; and (3) straight-time labor when responding to CEMA-eligible events.[1000]

PG&E records expense for Electric Emergency Recovery in two Major Work Categories: MWC BH Routine Emergencies and MWC IF Major Emergencies. PG&E records capital expenditures for Electric Emergency Recovery in MWC 17 Routine Emergencies and MWC 95 Major Emergency. PG&E states that it records emergencies that rise to the catastrophic level in the CEMA accounts. PG&E describes activities to support emergency response plans that include costs for staffing levels, roles and responsibilities, emergency

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[996] PG&E Opening Brief at 446.

[997] PG&E Opening Brief at 446.

[998] PG&E Opening Brief at 446 (includes September 6, 2022 updated escalation at PG&E Ex-33).

[999] PG&E Opening Brief at 447 (includes September 6, 2022 updated escalation at PG&E Ex-33).

[1000] PG&E Opening Brief at 446.

incident assessment guidelines, and communication plans, as well as emergency centers and mobilization crews and other resources. PG&E proposes to continue its two-way Major Emergency Balancing Account (MEBA) for its capital and expense incurred for major emergencies.[1001] The purpose of the MEBA is, according to PG&E, "to recover actual expenses and capital" not eligible for recovery through CEMA.[1002] PG&E also proposes a new two-way balancing account, which PG&E refers to as the Catastrophic Events Straight-Time Labor Balancing Account (CESTLBA).[1003] PG&E explains that, if the Commission approves this new balancing account, PG&E will stop recording catastrophic event straight-time labor costs to the CEMA.[1004]

The Commission addresses the contested capital requests and expense forecasts below. The Commission also addresses PG&E's request for a new balancing account.

4.6.1. Routine Emergency Capital (MWC 17) and Major Emergency Capital (MWC 95)

Cal Advocates' recommends a reduced capital expenditure forecast for both MWC 17 Routine Emergency and MWC 95 Major Emergency, as follows: $213.966 million for 2021, $251.050 million for 2022, and $257.721 million for 2023.[1005] Cal Advocates' forecast is based on a five-year average of historical costs from 2015-2019, rather than the three-year average from 2018-2020 because PG&E had an abnormally high Routine Emergency capital cost in 2020,

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[1001] PG&E Ex-04 at 2-10.

[1002] PG&E Ex-04 at 2-10.

[1003] PG&E Ex-04 at 2-10.

[1004] PG&E Ex-04 at 2-10.

[1005] Cal Advocates Opening Brief at 181.

compared to any year from 2013-2019.[1006] Cal Advocates also recommends reducing the forecast based on PG&E's completion of risk mitigation work, which Cal Advocates claims should reduce the occurrence of future catastrophic events and associated costs.[1007]

In response, PG&E states that a three-year average more closely reflects current labor and materials and Cal Advocates' five-year average excludes the data from the most recent full year (2020).[1008] PG&E also states that 2020 costs were not abnormally high when considering that recorded costs for Routine Emergency have increased annually for the past five years, with a 13.3% percentage increase from 2018 to 2019 and a 16.4% increase from 2019 to 2020.[1009] In addition, PG&E suggests that Cal Advocates' recommended reduction based on the PG&E's completion of future risk mitigation work is speculative.[1010]

Cal Advocates acknowledges that the preferred method of calculating reductions in PG&E's emergency work "requires detailed cost information that is not available."[1011] Instead, Cal Advocates explains it utilized a more generalized methodology based on PG&E's estimated distribution electric infrastructure related Risk Assessment Mitigation Phase risk scores before and after

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[1006] Cal Advocates Opening Brief at 180.

[1007] Cal Advocates Opening Brief at 180-181.

[1008] PG&E Opening Brief at 448-449.

[1009] PG&E Reply Brief at 390.

[1010] PG&E Opening Brief at 448-449.

[1011] Cal Advocates Opening Brief at 181, *citing to* CALPA Ex-16 at 12-13.

mitigations.[1012] Cal Advocates then reduced PG&E's emergency costs proportional to the reduction in risk scores.[1013]

The Commission is not persuaded by the forecast methodology presented by Cal Advocates. In addition, the Commission finds sufficient evidence that PG&E's recorded capital expenditures in 2020 for Routine Emergency activities were likely not abnormally high and that relying on PG&E's proposed three-year average for forecasting is reasonable. Accordingly, regarding Electric Emergency Recovery, the Commission adopts PG&E's capital expenditure request for MWC 17 Routine Emergency and MWC Major Emergency of $277.941 million for 2021, $339.418 million for 2022, and $360.523 million for 2023.

4.6.2. Straight-Time Labor Costs and CEMA Events

PG&E proposes to recover straight-time labor costs associated with CEMA-eligible events (CEMA straight-time labor costs) in this proceeding, rather than through the current memorandum account framework, known as CEMA. PG&E presents an expense forecast and capital forecast for CEMA straight-time labor.[1014] PG&E's 2023 expense forecast for CEMA straight-time labor costs is $23.2 million. PG&E proposes to track some of these costs in MWC IF Major Emergency Expense and in other areas of the company's operations, as noted in the below table. The majority of this forecast falls within PG&E's Electric Distribution line of business, as reflected in MWC IF Major Emergency Expense. PG&E's expense forecast for MWC IF Major Emergency Expense is $62.788 million, which includes $20.079 million for CEMA straight-time labor

[1012] Cal Advocates Opening Brief at 181, *citing to* CALPA Ex-16 at 12-13.

[1013] Cal Advocates Opening Brief at 181, *citing to* CALPA Ex-16 at 12-13.

[1014] PG&E Ex-04 at 6-26.

costs. Additional expense and capital forecasts included in PG&E's CEMA straight-time labor costs are as follows:[1015]

Table 4-G:
Catastrophic Event St Labor Expense Forecast
(Thousands Of Nominal Dollars)

Line No.	LOB	MWC	2023
1	Customer Care	IG	$144
2	Electric Distribution	IF	20,079
3	Gas Operations	LX	2,878
4	Generation	LX	84
5	**Total**		**$23,186**

Table 4-H:
Catastrophic Event St Labor Capital Forecast
(Thousands Of Nominal Dollars)

Line No.	LOB	MWC	2023	2024	2025	2026
1	Electric Distribution	95	$16,375	$16,817	$17,271	$17,738
2	Gas Operations	3Q	2,098	2,151	2,200	2,251
3	Generation	3Q	121	124	127	129
4	**Total**		**$18,595**	**$19,092**	**$19,598**	**$20,118**

Cal Advocates opposes PG&E's request seeking authorization for these straight-time labor costs outside of the CEMA process and, as a result, Cal Advocates recommends removing $20.079 million associated PG&E's forecast for CEMA straight-time labor costs from MWC IF Major Emergency

[1015] PG&E Ex-04 at 6-26 (Table 6-10 and Table 6-11).

Expense forecast.[1016] PG&E did not contest this recommendation.[1017]
Cal Advocates states that "PG&E cannot precisely predict the frequency, duration, and scope of declared catastrophic events and associated costs that may occur in a given year. There is substantial variability in declared catastrophic events and associated costs year-to-year."[1018]

The Commission finds Cal Advocates' recommendation reasonable and agrees that PG&E should remove these costs from its forecast for MWC IF and that all CEMA straight-time labor expenses should continue to be recorded in CEMA and recovered under the CEMA process, rather than through the forecasting process established in this proceed. Under the rationale presented by Cal Advocates that no evidence exists that PG&E can reasonably predict potential future CEMA events, the Commission finds it reasonable to remove both PG&E's expense forecast and capital forecasts for CEMA straight-line labor. The tables above that illustrate PG&E's request, which spans across several areas of operations.

Accordingly, after deducting the amount of $20.079 million, the Commission adopts an expense forecast for MWC IF Major Emergency Expense in 2023 of $42.709 million. The Commission also finds it reasonable to remove those amounts associated with PG&E's 2023 expense forecast for CEMA straight-time labor from the other areas of PG&E's operations noted above and, as a result, adopts reductions to PG&E's 2023 expense forecasts as following: PG&E's expense forecast for MWC IG (Customer Care) is reduced by $144,000, PG&E's expense forecast for MWC AB (Gas Operations) is reduced by

[1016] Cal Advocates Opening Brief at 481-483.

[1017] PG&E Opening Brief at 446; PG&E Reply Brief at 393.

[1018] Cal Advocates Opening Brief at 482.

$2.878 million, PG&E's expense forecast for MWC LX (Generation) is reduced by $84,000. Regarding PG&E's 2023 capital forecasts, the Commission reduces PG&E's 2023 capital forecast as follows: PG&E's 2023 capital forecast for MWC 95 (Electric Distribution) is reduced by $16.375 million, PG&E's 2023 capital forecast for MWC 21 (Gas Operations) is reduced by $2.098 million, PG&E's 2023 capital forecast for MWC 3Q (Generation) is reduced by $121,000.

4.6.3. Catastrophic Event Straight Time Labor Balancing Account

As described by PG&E, its proposed new two-way balancing account, which PG&E refers to as the CESTLBA, would provide PG&E with the opportunity to recover straight time labor costs associated with its repair and restoration activities for CEMA-eligible events. Under the proposed two-way balancing account, PG&E states it would stop recording CEMA straight-time labor costs to the memorandum account known as CEMA and, as a result, PG&E's applications seeking recovery of the costs recorded in the CEMA would only seek recovery of non-labor-related expense, capital expenditures, certain limited overheads, and overtime and double time labor costs associated with PG&E's repair and restoration activities following a CEMA-eligible event. PG&E proposes that, as part of this new balancing account, the Commission authorize a the provision that any underspent amount (less than the forecast) would be returned to customers and overspent amounts (more than the forecast) would be allowed for recovery and, in addition, the CESTLBA would be trued up annually through PG&E's annual electric and annual gas true up advice letters.[1019] PG&E states that it proposes this new two-way balancing account due to the disputes

[1019] PG&E Opening Brief at 393 and 451.

regarding the recovery of CEMA straight-time labor costs in cost-review application proceedings and the resulting uncertainty regarding recovery.

Cal Advocates and TURN oppose PG&E's proposal for the new balancing account. Cal Advocates states that costs associated with CEMA-events must be reviewed for reasonableness prior to recovery from ratepayers and, that contrary to this purpose of including a reasonableness review, PG&E's proposal would record costs associated with a CEMA event in a balancing account other than CEMA, which would risk omitting the reasonableness review of such costs and leave these costs to be approved through a GRC approval.[1020] Similarly, TURN opposes PG&E's proposal because PG&E has not established in this proceeding that there are actual incremental straight-time labor costs associated with CEMA events.[1021] TURN suggest that PG&E's CEMA response work is funded is performed by PG&E crews who conduct Routine Emergency response and no additional costs are incurred.[1022] In addition, TURN states that to the extent that PG&E can demonstrate that it actually incurred additional straight-time labor costs associated with specific CEMA events that were not funded, PG&E can request recovery of straight-time labor costs in a CEMA application within the reasonableness review process.[1023]

In response, PG&E states that PG&E's GRC forecasts are activity based and seek funding for work activities (not staffing) specifically identified in the GRC, and that PG&E specifically removed CEMA recorded costs (including CEMA Straight Time labor) from the recorded costs used to develop PG&E's rate case

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[1020] Cal Advocates Opening Brief at 162.

[1021] PG&E Opening Brief at 432.

[1022] TURN Opening Brief at 431-436.

[1023] TURN Reply Brief at 432.

forecasts. PG&E states that it seeks to avoid the following circumstances: (1) PG&E not recovering incremental CEMA straight-time labor costs in a CEMA proceeding based on arguments that all straight-time labor costs are already forecasted and recovered in a GRC; and (2) PG&E being prohibited from fully forecasting straight time labor in a GRC to include CEMA straight-time labor because CEMA costs can only be recovered upon a showing of incrementality.[1024] PG&E claims that a catastrophic event straight-time labor balancing account is needed because PG&E has historically not requested nor received funding in a GRC for straight-time labor necessary to respond to CEMA events. PG&E claims further that the proposed CESTBLA is needed to remedy this funding shortfall, to the extent costs for all PG&E staff activities (non-CEMA and CEMA) are to be funded solely through the GRC, as contended by Cal Advocates and TURN, and the uncertainty of the remedy.[1025] As evidence of the uncertainty, PG&E cites to the proposed decision and alternate proposed decision in CEMA proceeding A.20-09-019, in which the former found PG&E's 2020 CEMA straight-time labor costs to be not incremental to rate case-authorized amounts[1026] and the later approved a settlement that found sufficient evidence supporting the incrementality of CEMA straight-line labor costs.[1027]

The Commission does not find the uncertainty described by PG&E to be sufficient to justify establishing a new two-way balancing account for straight-line labor catastrophic events. Accordingly, the Commission denies

[1024] PG&E Opening Brief at 453-454; PG&E Reply Brief at 394.

[1025] PG&E Reply Brief at 395.

[1026] PG&E Reply Brief at 399.

[1027] PG&E Reply Brief at 399.

PG&E's request to establish the new balancing account, referred to by PG&E as the CESTLBA.[1028]

4.6.4. Documentation of CEMA Costs

TURN requests that the Commission direct PG&E in future GRCs to provide additional transparency surrounding its Major Emergency Balancing Account forecast and, specifically, PG&E's adjustments to remove CEMA costs recorded to MWC IF Major Emergency Expense and MWC 5 Routine Emergency Capital. More specifically, TURN requests that the Commission direct PG&E to explain whether its CEMA adjustments include all costs attributed to CEMA events or a subset of those costs, such as CEMA costs authorized for recovery (if less than 100% of recorded costs).[1029] In addition, TURN requests that to the extent that CEMA recorded costs are larger than authorized costs, and PG&E removes only authorized costs, PG&E should explain why the disallowed costs should be included in the forecast for MEBA.[1030]

In response, PG&E states that TURN's suggestions are vague and unnecessary and more appropriate for discovery.[1031]

The Commission finds that additional information would help clarify PG&E's requests for cost recovery. As such, in PG&E's CEMA proceedings and in its next GRC, PG&E shall:

(1) provide information on all costs attributed to CEMA events;

[1028] PG&E Opening Brief at 332. For the same reasons, the Commission denies PG&E's CEMA Straight-Time Labor forecasts in other areas including related to PG&E's requested forecast for MAT AB# and MAT 21#.

[1029] TURN Opening Brief at 441-442.

[1030] TURN Opening Brief at 441-442.

[1031] PG&E Reply Brief at 402.

(2) document whether adjustments to any MWC to remove CEMA costs recorded in PG&E's Major Emergency Balancing Account include all costs attributed to CEMA events; and

(3) if adjustments above do not include all costs attributed to CEMA events, document the part that the adjustments to CEMA recorded costs include.

In addition, if PG&E only removes authorized costs, PG&E must explain why costs above Commission authorized costs should be included in cost recovery related to the Major Emergency Balancing Account.

4.7. Distribution System Operations

PG&E states that its Distribution System Operations continuously (24/7) monitors the electric distribution system, manages outage restoration, and directs system switching, relying on technology in support of these activities.[1032] PG&E states that Distribution System Operations also manages electric-related customer service field work.[1033] PG&E's 2023 expense forecast is $60.531 million.[1034] PG&E's 2020 recorded expense is $55.3 million.[1035] The expense forecast includes work tracked in the three Major Work Categories: MWC BA Electric Distribution Operation Activities; MWC DD Customer Field Service Work; and MWC HG Distribution Operational Technology.[1036] PG&E's capital expenditures forecast presented is $4.255 million in 2021, $4.899 million in 2022, $5.243 million in 2023, $2.696 million in 2024, $2.733 million in 2025, and

[1032] PG&E Ex-04 at 7-1.

[1033] PG&E Ex-04 at 7-1.

[1034] PG&E Opening Brief at 454. (Including the escalation rates in the September 6, 2022 Update Testimony at PG&E Ex-33.)

[1035] PG&E Ex-04 at 7-1.

[1036] PG&E Opening Brief at 454.

$2.771 million in 2026.[1037] PG&E's 2020 recorded capital expenditures is $1.1 million.[1038] PG&E states that the forecasted increase is due to the establishment of the Operational Business Intelligence team, which is focused on building a technical solution to help improve business processes around safety, compliance, and wildfire mitigation.[1039] PG&E states that it records capital expenditures in MWC 63 Distribution Operational Technology.[1040] PG&E's expense forecast and capital expenditures requests are not contested. The Commission finds these requested amounts reasonable and adopts them.

4.8. Field Metering

PG&E states that its Field Metering organization is primarily responsible for its SmartMeter module and Electric Metering-related work activities at customer locations.[1041] PG&E states that, in collaboration with other departments, it manages more than 10 million gas and electric meters and directly serves customers with field activities including manual meter reading, meter installation, meter testing, and meter asset maintenance.[1042]

PG&E's 2023 expense forecast for Field Metering is $23.161 million.[1043] PG&E's 2020 recorded expenses for Field Metering is $20.4 million.[1044] PG&E

[1037] PG&E Opening Brief at 454. (Including the escalation rates in the September 6, 2022 Update Testimony at PG&E Ex-33.)

[1038] PG&E Ex-04 at 7-2.

[1039] PG&E Ex-04 at 7-3.

[1040] PG&E Ex-04 at 7-2.

[1041] PG&E Ex-04 at 8-1.

[1042] PG&E Ex-04 at 8-1.

[1043] PG&E Opening Brief at 455. (Includes the September 6, 2022 Update Testimony escalation adjustments at PG&E Ex-33).

[1044] PG&E Ex-04 at 8-2.

states that the increase is primarily attributable to labor escalation and legacy meter programming activities associated with the evolution of time variant pricing rates and their universal application to all PG&E electric customers.[1045] PG&E tracks these expenses in five Major Work Categories.[1046] PG&E capital expenditures forecast, including the September 6, 2022 escalation adjustment, is $83.595 million in 2021, $98.063 million in 2022, $123.978 million in 2023, $138.360 million in 2024, $113.523 million in 2025, and $89.043 million in 2026.[1047] PG&E states that its capital increase are "primarily due to an increase in the number of non-communicating gas Advanced Metering Infrastructure (AMI) modules that need to be exchanged in the field, and labor escalation."[1048] The disputed areas of PG&E's request regarding Field Metering are addressed below.

4.8.1. Field Metering Revenue Collection

PG&E states that its Field Metering Revenue Collection Program includes activities focused on customer energy theft, such as work to detect, investigate, and resolve energy theft.[1049] PG&E tracks these expense in MWC IU Collect Revenues.[1050] PG&E's 2023 expense forecast for MWC IU Field Metering Revenue Collection is $2.3 million, which is $0.8 million higher than 2020 recorded costs of

[1045] PG&E Ex-04 at 8-2.

[1046] PG&E Opening Brief at 455. PG&E tracks these expenses in five Major Work Categories; four of these are uncontested – Read and Investigate Meters (MWC AR); Provide Field Services (MWC DD); Change/Maintain Used Electric Meters (MWC EY); and Change/Maintain Used Gas Meters (MWC HY). The contested forecast is tracked in Collect Revenue (MWC IU).

[1047] Opening Brief at 455. PG&E tracks capital work in two Major Work Categories, Install New Electric Meters (MWC 25) and Install New Gas Meters (MWC 74).

[1048] PG&E Ex-04 at 8-2.

[1049] PG&E Ex-04 at 8-3.

[1050] PG&E Ex-04 at 8-3.

$1.5 million.[1051] PG&E describes the drivers for the increase (approximately 53%) as labor escalation and the projected increase in field employees necessary to support energy theft investigations.[1052]

TURN recommends reducing PG&E's expense forecast by $0.72 million to $1.58 million, which reflects PG&E's 2021 recorded expense plus escalation, because PG&E fails to support its requested increase with any data, such as the historical or forecasted number of energy theft investigations.[1053] In this respect, TURN states that PG&E has not carried its burden of proof.[1054] TURN further states that, contrary to the volume of work reflected in PG&E's increased expense forecast, PG&E's data shows that the number of PG&E energy theft investigations declined over the past five years, from 7,360 investigations in 2017 to 3,328 investigations in 2021.[1055]

In response, PG&E states that recent spending for energy theft activities has been relatively lower in recent years because of staff attrition during a three-year transition, starting in 2017, from staff being non-represented technical employees to an IBEW union represented workforce.[1056] PG&E also attributes the decline to the COVID-19 related moratoriums on Shut-Off for Non-Payment. For this rate case period, PG&E projects that its energy theft investigations will increase significantly once the Shut-Off for Non-Payment moratorium expires in

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[1051] PG&E Ex-04 at 8-8; PG&E Opening Brief at 456.

[1052] PG&E Ex-04 at 8-9.

[1053] TURN Opening Brief at 441-443.

[1054] TURN Opening Brief at 442.

[1055] TURN Opening Brief at 443.

[1056] PG&E Ex-17 at 8-5.

late 2022.[1057] In addition, PG&E contends that it expects the number of energy theft investigations to increase due to PG&E's restructuring of the revenue assurance function and the modernizing of its work-flow process.[1058]

The Commission finds that, while PG&E seeks to increase the pace and number of its energy theft investigations, it does not provide details regarding its plan or sufficient information to support its forecast of increasing the number of future energy theft investigations. In the absence of persuasive evidence on how an increased number of energy theft investigation will be required based on its customer population, the Commission does not find PG&E's forecasted annual number of investigations to be a reasonable basis for an expense forecast. In contrast, the Commission finds TURN's arguments based on historical data persuasive. Accordingly, the Commission adopts TURN's recommended 2023 expense forecast for Field Metering Revenue Collection Program of $1.58 million, rather than PG&E's 2023 expense forecast of $2.3 million. Therefore, the Commission reduces PG&E's total 2023 expense request for Field Metering of $23.161 million by $0.72 million to reflect the lower forecast for MWC MAT IU Field Metering Revenue Collection. The Commission finds the remaining uncontested aspects of PG&E's expense forecast reasonable and adopts these expense forecasts.

4.8.2. Field Metering Capital

In explaining recent changes in its organizational structure pertaining to Field Metering, PG&E states that previously all PG&E's metering costs were presented within Customer Care but in 2018 PG&E moved the Field Metering

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[1057] PG&E Ex-17 at 8-5.

[1058] PG&E Opening Brief at 455-457.

organization from within Customer Care to Electric Operations but certain aspects of metering costs, such Meter Service and Engineering remained within Customer Care, as set forth in PG&E Ex-06.[1059] PG&E explains that field metering installations work tracked in MWC 74 Gas Metering Capital includes the labor and support costs necessary to perform AMI gas module installations, maintenance, exchanges, and removals at customer locations.[1060] PG&E presents a 2023 capital forecast of $74.4 million for MWC 74.[1061] PG&E's 2023 forecast is $56.2 million higher than 2020 recorded costs of $18.2 million.[1062] Regarding MWC 25 Electric Metering Capital, PG&E's 2023 capital expenditure forecast is $30.1 million. PG&E's 2020 recorded capital expenditures were $24.2 million.[1063] PG&E states that the primary driver is corrective maintenance related to "labor escalation and continued incremental increases in corrective maintenance for SmartMeter electric meters" discussed in Section 6.6, herein.[1064]

Cal Advocates and TURN recommend reductions to the capital forecast for MWC 74 Gas Metering Capital. Cal Advocates recommends an adjustment to PG&E's forecast for MWC 74 based on 2021 recorded costs.[1065] TURN recommends no cost recovery until the Commission determines the extent to

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1059 PG&E Ex-04 at 8-1; PG&E Ex-04 at 8-4 (fn. 6), citing to PG&E Ex-06, ch. 9, Gas AMI Module Replacement. PG&E states "the forecast for electric meter purchase is included in Exhibit (PG&E 6), Ch. 7, Metering Services and Engineering."

1060 PG&E Opening Brief at 455.

1061 PG&E Ex-04 at 8-9.

1062 PG&E Ex-04 at 8-9.

1063 PG&E Ex-04 at 8-9.

1064 PG&E Ex-04 at 8-9.

1065 Cal Advocates Opening Brief at 353.

which PG&E was responsible for the failure of the AMI gas metering modules.[1066]

The Commission addresses the arguments presented by TURN and Cal Advocates regarding MWC 74 at Section 6, herein, within the topic of Customer and Communications – Gas AMI Module Replacement, which addresses costs associated with replacing defective AMI modules. The Commission does not make any findings or conclusion regarding PG&E's capital forecast for MWC 74 here.

4.9. Vegetation Management

PG&E's 2023 expense forecast is approximately $1.31 billion.[1067] PG&E tracks vegetation management in MWC HN Routine Vegetation Management and two subaccounts, MAT IGJ Enhanced Vegetation Management and MAT IGI Tree Mortality Work.[1068]

PG&E explains it will transition to a "One Veg" program, which includes a plan to eliminate the separate Enhanced Vegetation Management (EVM) Program.[1069] PG&E also explains that it modified and lowered its vegetation management forecast in its February 28, 2022 revised testimony.[1070] PG&E's initial forecast, on June 30, 2021, was $1.196 billion. PG&E explains how this

[1066] TURN Ex-13 at 12-13.

[1067] PG&E Opening Brief at 459. (Includes the escalation rates in PG&E's September 6, 2022 Update Testimony.)

[1068] PG&E Opening Brief at 459.

[1069] PG&E Ex-04 at 9-2.

[1070] PG&E lowered its forecast in its February 25, 2022 revised testimony but its request of $1.31 billion is higher than its June 30, 2021 of $1.196 billion request because its lower forecast plus the September 6, 2022 adjusted escalation results in a request that is higher than its original June 30, 2021 request.

modification relates to its February 28, 2022 "updated wildfire mitigation strategy," as follows:

> PG&E describes its updated wildfire mitigation strategy. This integrated strategy focuses on increasing the number of miles and pace of system hardening undergrounding for long-term, permanent wildfire risk reduction and expanding the Enhanced Powerline Safety Settings (EPSS) Program to provide near-term risk reduction. Electric distribution system undergrounding will help substantially reduce wildfires caused by PG&E equipment and reduce the frequency and/or duration of Public Safety Power Shutoff (PSPS) and EPSS outages. EPSS consists of making seasonal adjustments to PG&E's powerline safety settings to make them more sensitive to detecting faults and reducing fault currents, thereby reducing the risk of an ignition. See Exhibit (PG&E-4) Chapter 4.6 for additional information on the EPSS Program.[1071] The proposed 2023-2026 wildfire mitigations focused on undergrounding and EPSS will result in a higher risk spend efficiency and greater risk reduction for each dollar spent. This new, comprehensive approach also enables PG&E to further evolve its electric distribution VM programs. During this rate case period, PG&E will lower the cost of VM by: (1) changing the scope of the Enhanced VM program; (2) reducing the amount of Routine VM work conducted each year commensurate with the amount of undergrounding miles completed; and (3) reducing unit costs through efficiencies for Routine VM, EVM and Tree Mortality by approximately 20 percent over the rate case period through

[1071] [(footnote not in original) PG&E Ex-04 at 9-3, PG&E further explains the connection between vegetation management and EPSS, stating "To address this continuously evolving wildfire risk, PG&E implemented the EPSS Program in July 2021 on approximately 11,500 miles of distribution circuits, or 45 percent of the circuit miles in HFTD areas. With EPSS, if an object such as vegetation contacts a distribution line, power is automatically shut off within 1/10th of a second, reducing the potential for an ignition. This program had a dramatic impact, decreasing CPUC-reportable ignitions from electrical equipment on EPSS enabled circuits by 80 percent compared to a three-year average. In 2022, PG&E will expand the EPSS Program to all circuits within the HFTD and High Fire Risk Area, as well as some circuits within HFTD buffer zones."

targeted programmatic adjustments that refine processes and improve resource efficiency. These changes result in a reduction to PG&E's June 30, 2021 VM forecast of approximately $1 billion expense over the rate case period.[1072]

PG&E states that these changes to its 2023-2026 wildfire mitigation vegetation management, as reflected in the February 25, 2022 revised forecast, result in a reduction approximately $1.022 billion in expense over the rate case period (2023-2026).[1073] PG&E states that this reduction reflects a "change in the scope of the Vegetation Management programs commensurate with PG&E's increased system hardening and undergrounding work in the HFTDs, application of EPSS across its HFTD distribution circuits, and PG&E's commitment to reducing the costs of its Vegetation Management programs."[1074] PG&E's expense forecasts for its three vegetation programs, revised to reflect its updated wildfire mitigation strategy is set forth in the below table. PG&E's forecast for Vegetation Management does not include any capital forecast. The table includes Cal Advocates' recommended adjustments, which are addressed below.

Table 4-I:[1075]
Vegetation Management - PG&E's Expense Forecast And Parties Recommended (Reductions)/Increases ($000s)[(a)]

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E Routine VM	$693,149	$668,123	$711,007	$871,220	$844,736	$800,294	$727,548
PG&E Enhanced VM	$451,390	$535,952	916,600	$118,022	$117,555	$112,177	$102,234
PG&E Tree Mortality	$93,070	$67,978	144,000	$69,830	$70,423	$71,003	$70,396

1072 PG&E Ex-04 at 9-2.

1073 PG&E Ex-04 at 9-4, stating that the June 30, 2021 forecast for 2023-2026 was $4.977 billion.

1074 PG&E Ex-04 at 9-4.

1075 PG&E Opening Brief at 460 (Table 4-14). The amounts noted for PG&E do not include modifications to the requested amounts due to the September 6, 2022 updated escalation rates.

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E Total VM	$1,237,610	$1,272,053	1,771,608	$1,059,072	$1,032,714	$983,475	$900,178
Cal Adv Routine VM				$(427,316)			
Cal Adv Enhanced VM				$292,327			
Cal Adv Tree Mortality				**$-**			
Cal Adv Total VM				**$(134,988)**			

(a) PG&E-17, p. 9-3, Table 9-1, lines 1-4; p. 9-17, Table 9-2, lines 1-4.

Cal Advocates recommends a total reduction to the 2023 forecast of $134.988 million.[1076]

4.9.1. Tree Mortality Program

PG&E's expense forecast of $70.771 million ($69.830 million reflected in the above table does not reflect PG&E's September 6, 2022 adjusted escalation rates in PG&E Ex-33) for 2023 for the Tree Mortality program is uncontested. PG&E states that its costs for the Tree Mortality Program, which is one of several programs tracked in MWC IG, were previously tracked in CEMA and have not been forecasted in a GRC.[1077] PG&E's 2020 GRC decision directed PG&E to start tracking all vegetation management costs, including the Tree Mortality Program, in the Vegetation Management Balancing Account beginning in 2020.[1078] PG&E's requested expense forecast of $70.771 million for its Tree Mortality Program in 2023 is a decrease of $21.156 million from PG&E's 2020 recorded expenses of $93.070 million.[1079] PG&E states that no material changes to this program were

[1076] Cal Advocates Opening Brief at 193. $924.084 million includes $443.904 million for Routine Vegetation Management, $409.409 million for Enhanced Vegetation Management, and the remaining amount is for Tree Mortality. Cal Advocates made its recommendation based on PG&E's June 30, 2021 forecast, not PG&E's February 25, 2022 forecast.

[1077] PG&E Ex-04 at 9-49.

[1078] D.20-12-005, *Decision Addressing the Test Year 2020 General Rate Case of Pacific Gas and Electric Company* (December 3, 2020) at 67.

[1079] PG&E Ex-04 at 9-49.

presented in PG&E's February 25, 2022 revised testimony.[1080] PG&E also states that it is not changing the scope of its Tree Mortality Program. PG&E also notes that in 2022 its Enhanced Vegetation Inspection and Mitigation under Tree Mortality account reflected expenses of $119.517 million.[1081] Cal Advocates does not oppose PG&E's 2023 Tree Mortality Program expense forecast.[1082] The Commission finds this uncontested expense amount reasonable for PG&E's 2023 Tree Mortality Program forecast of $70.771 million.

4.9.2. Routine and Enhanced Vegetation Management

PG&E states that its Routine Vegetation Management Program is based on an annual patrol of all PG&E distribution lines to support compliance with Commission General Order 95, Rule 35 of the Commission's Rules of Practice and Procedure, and Public Resource Code Sections 4292 and 4293.[1083] PG&E's states that its Routine Vegetation Management Program forecast is higher than the 2020 recorded costs primarily due to the change in scope related to PG&E's new wildfire mitigation strategy.[1084] According to PG&E, its Routine VM now includes an "enhanced process to perform visual assessments" of all sides of potential strike trees on routine vegetation management patrols in HFTDs, tree risk assessments to identify hazard trees, and hazard tree removal.[1085] PG&E explains that increased costs due to scope of work changes are partially offset by

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[1080] PG&E Ex-04 at 9-49.

[1081] PG&E Ex-04 at 9-49.

[1082] Cal Advocates Opening Brief at 182.

[1083] PG&E Opening Brief at 459.

[1084] PG&E Ex-04 at 9-8.

[1085] PG&E Ex-04 at 9-8.

reduced unit costs and lower headcount for Quality Assurance and Quality Verification work.[1086]

Regarding Enhanced Vegetation Management, PG&E states that on October 31, 2022, PG&E filed a 90-Day Report concerning its Corrective Action Plan in the Enhanced Oversight and Enforcement Process pursuant to Commission Resolution M-4852.[1087] PG&E explains that the report provides an overview of PG&E's 2023 plans for its Vegetation Management program, which include a restructuring of the program based on a risk-informed approach for its portfolio of wildfire mitigations, including considering Risk Spend Efficiency.[1088] PG&E states that, based on recent data and analysis, its risk reduction analysis finds that the risk reduction of the Enhanced Vegetation Management Program is lower than the risk reduction from the EPSS, which PG&E introduced in 2021, and other PG&E operational mitigations, such as its partial voltage capabilities.[1089] Additionally, PG&E states that, while its Enhanced Vegetation Management Program has reduced wildfire risk, it has been hampered by landowner refusals.[1090] As a result, PG&E plans to sunset the Enhanced Vegetation Management Program at the end of 2022.[1091] PG&E states that it will continue, and enhance, its other existing vegetation management programs.[1092]

1086 PG&E Ex-04 at 9-8.

1087 PG&E Opening Brief at 460.

1088 PG&E Opening Brief at 460.

1089 PG&E Opening Brief at 460.

1090 PG&E Opening Brief at 460.

1091 PG&E Opening Brief at 460.

1092 PG&E Opening Brief at 460.

PG&E does not expect these program changes will change the amount of funding it needs for Vegetation Management.[1093]

As set forth in the table above, Cal Advocates recommends a lower 2023 forecast for the combined Routine Vegetation Management and Enhanced Vegetation Management Programs based on a three-year average (2018-2020) of recorded Routine Vegetation Management costs instead of using just PG&E's 2020 recorded costs. According to Cal Advocates, its three-year average is more accurate than a forecast based on a single year (2020) used by PG&E because of the variability and uncertainty of routine Vegetation Management expenses each year and the higher costs in 2020. Cal Advocates states that PG&E's 2020 recorded expense of $693.149 million is $463.879 million higher than its 2020 authorized forecast of $229.27 million. Cal Advocates notes that the reasonableness of some of PG&E's 2020 recorded expenses, which are tracked in the Vegetation Management Balancing Account,[1094] are being considered separately by the Commission and could be deemed non-recoverable in rates. Cal Advocates states that these expense must be reviewed by the Commission in a separate proceeding, such as A.20-09-019,[1095] A.21-09-008, and A.22-12-009 (which PG&E calls its *PG&E Wildfire Mitigation and Catastrophic Events* proceedings).[1096] Based on its review of these pending application, Cal Advocates

[1093] PG&E Opening Brief at 460.

[1094] PG&E Ex-04 at 9-5 (fn. 10) "In accordance with PG&E's Test Year (TY) 2020 GRC Decision, D.20-12-005, OP 1 at 409-411, PG&E modified its VMBA, effective January 1, 2020, to track and record actual expenses for all of PG&E's electric distribution vegetation mitigation activities, which includes vegetation management costs previously recorded in the CEMA."

[1095] In D.23-02-017, the Commission addressed the issues presented in A.20-09-019, adopting a settlement of the issues raised.

[1096] Cal Advocates Opening Brief at 195.

also contends that PG&E incurred anomalously high costs in 2020 for its Routine Vegetation Management Program and, therefore, this 2020 amount should not be used as a basis to forecast future expenses.[1097] In addition, Cal Advocates recommends removing certain costs related to Safety Oversight, Quality Verification and Quality Control from PG&E's 2023 forecasts because the hiring costs were incurred one time in 2020.[1098] For example, Cal Advocates points out that PG&E forecasts that its Contractor Safety Program costs will increase by $8.1 million (540%) over 2020 recorded costs of $1.5 million and that the "primary driver for this increase is hiring of the new PG&E Contractor Safety Manager and staff."[1099] According to Cal Advocates, PG&E's forecast assumes that PG&E will maintain approximately the same staffing level each year 2021-2023 but Cal Advocates contends that PG&E does not demonstrate that its 2023 forecast for Routine Vegetation Management will increase due to increased headcount for its Contractor Safety Program and its Safety Oversight, QV, and QA activity.[1100] For PG&E's Enhanced Vegetation Management Program, Cal Advocates similarly argues that PG&E's forecasts should not be adopted because PG&E uses only 2020 recorded costs instead of a three-year average.[1101] In addition, Cal Advocates describes anomalous Enhanced Vegetation Management Program costs in 2020 it argues should not be used as the basis for this forecast.[1102]

[1097] Cal Advocates Opening Brief at 195.

[1098] Cal Advocates Opening Brief at 195.

[1099] Cal Advocates Opening Brief at 197.

[1100] Cal Advocates Opening Brief at 178 to 179. Note: QV means Quality Verification; QA means Quality Assurance.

[1101] Cal Advocates Opening Brief at 199.

[1102] Cal Advocates Opening Brief at 200.

In response, PG&E states that Cal Advocates' recommended forecasts using the 2018-2020 average is not reliable because it fails to account for costs related to compliance with the vegetation related wildfire prevention requirements of Senate Bill 247 (Stats. 2019, Ch. 406), which PG&E states significantly increased PG&E's labor costs for both Routine and Enhanced Vegetation Management.[1103] PG&E estimates that the requirements of Senate Bill 247 increased its costs by approximately 49%.[1104] PG&E also states that Cal Advocates' recommendation to exclude costs for hiring a new safety manager and staff are based on the incorrect assumption that all hiring costs incurred in 2020 were one-time costs and that PG&E's staffing levels are not increasing.[1105] PG&E acknowledges that the initial hiring of a new safety manager and other staff in 2020 are one-time, non-recurring costs but explains that its forecast is not for those costs but for the continuing costs to pay the safety management staff.[1106] PG&E describes its staffing levels, noting that safety management staff in 2020 ranged from 50-75 contract employees whereas PG&E's 2023 forecast includes 70 in-house safety management staff.[1107] PG&E further states that the in-house safety management employees will be paid more than the contract workers they are replacing. PG&E states that it is reasonable to bring these resources in-house to address high contractor turnover that can negatively impact the consistency of contractors' training, experience and work

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[1103] PG&E Opening Brief at 461, PG&E states that "SB 247 established qualifications for line clearance tree trimmers and required that they be paid no less than the prevailing wage for a first period apprentice electrical utility lineman."

[1104] PG&E Reply Brief at 461.

[1105] PG&E Opening Brief at 462.

[1106] PG&E Opening Brief at 462.

[1107] PG&E Opening Brief at 462.

quality; improve the stability of the safety oversight team; ensure quality control management of this critical workforce; more easily screen applicants for appropriate levels of education and experience; and make it easier to identify and act on performance issues.[1108] PG&E also presents slightly declining expenses in years 2024, 2025, and 2026.[1109]

Given the extreme change in PG&E's vegetation management program costs in 2020 following the unprecedented fires in its service territory (2016 recorded expense at $382 million to 2022 recorded expense at $1.777 billion),[1110] the Commission agrees that PG&E's 2020 vegetation management costs were significantly higher than prior recorded costs but likely reflective of future costs. Therefore, the Commission finds that 2020 recorded expense provides a reasonable basis for PG&E's forecast expense in 2023. Accordingly, the Commission adopts PG&E's forecast of approximately $1.31 billion (as noted in above table) for MWC HN Routine Vegetation Management, which includes two subaccounts, MAT IGJ Enhanced Vegetation Management and MAT IGI Tree Mortality Work. During this rate case period, the Commission directs PG&E to continue to track vegetation management costs related to wildfire mitigation in the Vegetation Management Balancing Account, which is discussed below.

4.9.3. Vegetation Management Balancing Account

PG&E records its Vegetation Management Program expenses in a two-way balancing account, the Vegetation Management Balancing Account (VMBA). The Commission addresses the continuation and terms and conditions of the VMBA in Section 4.24, herein.

[1108] PG&E Reply Brief at 462.

[1109] PG&E Ex-04 at 9-69.

[1110] PG&E Ex-04 at 9-69.

4.10. Overhead and Underground Electric Asset Inspections

As part of its Electric Asset Inspection Program, PG&E personnel regularly inspect its 81,000 miles of overhead and approximately 26,000 miles of underground electric facilities, in compliance with General Order 165 and PG&E's internal standards, to identify areas of deterioration and degradation (as well as issues caused by outside forces and third-party encroachments) that could create unsafe conditions, outages, or wildfires.[1111] PG&E requests an expense forecast for 2023 of $106.340 million.[1112] PG&E's 2020 recorded costs are $160.684 million.[1113] PG&E states that the work of inspections is tracked in 12 MAT codes within one Major Work Category, MWC BF Overhead and Underground Inspections and Patrols.[1114] Parties contest one area of this forecast, which is tracked in MAT BFB Overhead Inspections.[1115] The Commission addresses this contested forecast, below. PG&E does not present a capital forecast associated with PG&E's Electric Asset Inspection Program.[1116]

Regarding the uncontested forecasts for 2023 expense tracked in MWC BF Overhead and Underground Inspections and Patrols, the Commission finds those amounts to be reasonable. The uncontested expense and capital expenditure forecasts are set forth at Appendix A of PG&E's Opening Brief at A-17 and A-25.

[1111] PG&E Ex-04 at 10-1 and PG&E Opening Brief at 463.

[1112] PG&E Opening Brief at 464. (Includes escalation rates in PG&E Ex-33 September 6, 2022 Update Testimony.)

[1113] PG&E Ex-04 at 10-36.

[1114] PG&E Opening Brief at 464. (Includes escalation rates in PG&E Ex-33 September 6, 2022 Update Testimony.)

[1115] PG&E Opening Brief at 463.

[1116] PG&E Opening Brief at 464.

4.10.1. Overhead Inspections

PG&E tracks costs in MAT BFB Overhead Inspections for activities that involve performing detailed inspections of electric distribution overhead assets, wherein inspectors assess system components, structures and equipment through visual observations and/or diagnostic tests to identify and document abnormal conditions that may adversely impact safety or reliability.[1117] PG&E requests a 2023 expense forecast of $58.807 million for MAT BFB Overhead Inspections.[1118] PG&E's bases its forecast on performing Field Safety Reassessments, which involve a field check of a condition needing correction to determine if the condition should be resolved earlier than scheduled.[1119]

TURN recommends reducing PG&E's 2023 MAT BFB Overhead Inspections expense forecast by $9.659 million to $49.148 million to account for the costs of Field Safety Reassessment that would not be required but for PG&E's work backlog.[1120] TURN states that a Field Safety Reassessment is an inspection that must occur only because PG&E fails to remedy an identified issue for correction by the deadline, necessitating an additional check on the condition.[1121] The backlog TURN refers to is the backlog of pole replacements that has been documented for several decades, not just the number of increased inspections since 2019.

PG&E disagrees that its increased number of Electric Correction notifications under the Wildfire Safety Inspection Program (WSIP) were due to

[1117] PG&E Opening Brief at 464.

[1118] PG&E Opening Brief at 465.

[1119] PG&E Ex-17 (Rebuttal) at 10-5.

[1120] TURN Opening Brief at 449.

[1121] TURN Opening Brief at 450; TURN Reply Brief at 113.

prior inspection failures.[1122] PG&E states that inspection activities prior to 2019 were sufficient for several reasons. PG&E states that its pre-2019 inspection activities were based upon the risks known at that time.[1123] PG&E states that pre-WSIP inspections met General Order 165 requirements. PG&E states that the many factors (such as extreme weather and environmental conditions, third-party caused damage, etc.) that cause equipment to degrade or fail are dynamic and entirely unpredictable.[1124] PG&E also states that the increased number of corrective notifications was due primarily to PG&E's decision to increase the inspectors' time horizon for assessing abnormal conditions that could cause a catastrophic wildfire.

Prior to 2019, PG&E explains that it used a one-year time horizon and focused on general safety and reliability issues.[1125] PG&E explains that wildfire risk was not a focus of its inspection prior to 2019 because, according to PG&E, the Commission did not require it. PG&E states "For rural areas from 1997 to 2012, for example, General Order 165 required patrols every two years and detailed inspections every five years, with no mention of wildfire risk issues."[1126] According to PG&E, "Wildfire was subsequently expressly identified as a potential risk in a 2012 amendment to GO 165 inspection requirements, but only for southern California counties."[1127] PG&E goes on to suggest that "It was not until several years later that the Commission amended GO 165 inspection

1122 PG&E Opening Brief at 465.

1123 PG&E Reply Brief at 407.

1124 PG&E Reply Brief at 408.

1125 PG&E Reply Brief at 409.

1126 PG&E Reply Brief at 409.

1127 PG&E Reply Brief at 409.

requirements to address wildfire risk for equipment in HFTDs throughout California."[1128] PG&E argues the Commission should not adopt TURN's recommendation because it lacks quantifiable analysis.[1129]

In 2019, PG&E adopted WSIP to change its criteria for inspecting poles and associated equipment in HFTD areas[1130] to be stricter than General Order 165 requirements. Such changes included the following: (1) a five-year time horizon, meaning that inspectors were instructed to identify any abnormal wildfire-risk conditions that could emerge and require maintenance within five years; (2) stricter inspection criteria and a focus on wildfire risk; and (3) a new WSIP checklist.[1131] Additionally, PG&E began conducting patrols and inspections on an accelerated, enhanced basis in HFTD areas more frequently than the minimum requirements of General Order 165, and documenting those patrols and inspections using digital records and photos (using electronic tablets) as opposed to paper records.[1132]

The Commission is not persuaded that PG&E's change in inspection criteria "suddenly" increased the number of poles tagged for corrective action by approximately four times the average annual inspection find rate in pre-WSIP years.[1133] PG&E also has not quantified the backlog or the number of poles tagged for correction that existed prior to the adoption of WSIP in 2019.

[1128] PG&E Reply Brief at 409.

[1129] PG&E Reply Brief at 412.

[1130] PG&E Ex-04 at 10-5.

[1131] PG&E Opening Brief at 466; PG&E Ex-17 (Rebuttal) at 10-6 to 10-8.

[1132] PG&E Reply Brief at 410.

[1133] PG&E Opening Brief at 475.

TURN arguments are persuasive and cast doubt on PG&E's request. The Commission finds TURN's recommendation to reduce the forecast for MAT BFB Overhead Inspections by $9.659 million to be reasonable and adopts a 2023 expense forecast for of $49.148 million.

4.11. Overhead and Underground Electric Distribution Maintenance

PG&E requests an expense forecast for 2023 of $111.580 million for its Electric Distribution Maintenance Program.[1134] PG&E's 2020 recorded expense is $132.7 million.[1135] PG&E's capital expenditures forecast is $488.196 million in 2021, $357.579 million in 2022, $388.822 million in 2023, $433.275 million in 2024, $446.332 million in 2025, and $453.752 million in 2026.[1136] PG&E explains that its separate program, the Overhead and Underground Inspections Program, includes work to identify correction notifications (known as tags) for degraded or damaged facilities that pose a safety or reliability risk, PG&E's Electric Distribution Maintenance program involves work to correct those conditions, as well as repairing and replacing other assets.[1137] PG&E states that it plans and executes the activities in the Electric Distribution Maintenance Program to meet the requirements of the Commission's General Order 95 and General Order 128, federal regulations, and PG&E internal standards.[1138] The disputed expense and capital cost categories are discussed below.

[1134] PG&E Opening Brief at 470. (Includes PG&E's escalation rates in PG&E Ex-33, the September 6, 2022 Update Testimony.)

[1135] PG&E Ex-04 at 11-1.

[1136] PG&E Opening Brief at 470 to 471. (Includes PG&E's escalation rates in PG&E Ex-33, the September 6, 2022 Update Testimony.)

[1137] PG&E Opening Brief at 469.

[1138] PG&E Opening Brief at 469.

4.11.1. Pace of Work for Capital Overhead and Underground Electric Distribution Maintenance Programs

PG&E proposes an increased pace of work compared to the 2018-2020 rate case period to make up for work deferred to address other wildfire-related work in the last rate case cycle.[1139] Cal Advocates contends that the record does not support PG&E's increased pace of work. Cal Advocates argues that PG&E's Risk Spend Accountability Report generally states that PG&E was required to defer maintenance work below the level of PG&E's 2018-2020 forecasts to focus on higher priority activities associated with the Wildfire Safety Inspection Program, Public Safety Power Shutoffs, HFTDs, System Hardening, or other higher risk maintenance work.[1140] Cal Advocates also point out that PG&E did not provide the specific MAT codes for areas that PG&E prioritized over this maintenance work during the 2018-2020 rate case cycle.[1141] Secondly, Cal Advocates contends that PG&E has not demonstrated that its increased pace of work is necessary.[1142] For example, Cal Advocates states that it requested information regarding how PG&E scoped out its pace of work for several of the programs, including MAT 2AC Bird Safe Installations program.[1143] Cal Advocates reports that PG&E only provided an estimate of the number of units it hopes to complete per year, not a justification for why such a pace of work is necessary.[1144] As a result,

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[1139] PG&E Ex-04 at 13-30. For MAT 08J (Overhead Conductor Replacement), PG&E states that its 2020 forecast is lower than its 2023 forecast because in 2020 PG&E had to address other higher priority work. Cal Advocates Opening Brief at 184.

[1140] Cal Advocates Opening Brief at 204 to 206.

[1141] Cal Advocates Opening Brief at 204.

[1142] Cal Advocates Opening Brief at 205.

[1143] Cal Advocates Opening Brief at 205.

[1144] Cal Advocates Opening Brief at 205.

Cal Advocates generally recommends capping 2021-2023 annual average pace of work based on the average number of units that PG&E completed per year from 2019-2021, or 2018-2020 if 2021 data is unavailable or not representative.[1145] For MAT codes that do not have unit costs or have non-representative number of units completed per year (e.g., completion of a unit generally spans multiple years), Cal Advocates recommends capping pace of work based on 2019-2021 average dollars, rather than annual units completed.[1146] For several, individual MAT codes, Cal Advocates additionally makes MAT code-specific adjustments, as described below.

In response, PG&E states that its pace of performing this work is reasonable for the following reasons: (1) limiting maintenance work could increase PG&E's wildfire and other electric system risk; (2) Cal Advocates bases its recommendations on speculation; and (3) PG&E has provided sufficient justification for all relevant programs.[1147] In further explanation, PG&E describes the importance of the work to maintaining system safety and reliability and that the pace of this work is based on regulatory requirements, PG&E standards and guidelines, and risk information and prioritization.[1148] PG&E states that Cal Advocates' suggestion that PG&E will operate at a reduced pace is speculative because Cal Advocates recommendation is based on a resource-constrained history that no longer exists and that PG&E will have the capacity to complete the work barring unforeseen events by aligning resources to

[1145] Cal Advocates Opening Brief at 205.

[1146] Cal Advocates Opening Brief at 206.

[1147] PG&E Reply Brief at 415.

[1148] PG&E Reply Brief at 416-417.

complete work as efficiently as possible.[1149] This resource-alignment effort includes establishing a Project Management Organization whose staff is focused on eliminating the need to move resources away from other work but only to support system hardening work.[1150]

The Commission considers the above arguments when addressing PG&E's requests for funding related to the Electric Distribution Maintenance Program.

4.11.2. Unit Cost of Overhead and Underground Electrical Distribution Maintenance

PG&E contends that its forecasts for overhead and underground electrical distribution maintenance are reasonable because they are based on 2019-2020 unit cost data that reflects current circumstances, including current market conditions and work plans[1151] and is more accurate than the 2016-2018 data used by TURN and Cal Advocates. TURN objects to PG&E's use of 2019-2020 unit data for this work because its unit costs have doubled and tripled, for example for MAT 2AA and MAT KAA, respectively. TURN attributes such cost increases to the onset of the Wildfire Safety Inspection Program PG&E adopted in 2019 and the backlog of work impacted by insufficient prior inspections.[1152]

In addition, TURN argues that PG&E has provided an insufficient justification for why costs for this work have increased. According to TURN, PG&E initially stated that the "higher volume [of work] required more contractor and overtime resources to complete the notifications." In rebuttal, however, PG&E attributed the increase in costs to doing more high priority work that costs

[1149] PG&E Reply Brief at 416.

[1150] PG&E Reply Brief at 416.

[1151] PG&E Reply Brief at 417.

[1152] TURN Opening Brief at 451-452.

more and fewer lower priority low-cost tags. And later, PG&E asserted that the increased costs are driven by both more costly labor and the fact that higher priority work is more likely to be in difficult to access areas which are more costly to remediate, rather than only more costly labor. However, TURN states that PG&E has not quantified how much each cost driver has increased costs;[1153] whether higher priority work is in fact more expensive to complete;[1154] and whether PG&E targets costly contract and overtime labor costs at the highest priority work.[1155]

To calculate its alternative unit cost, TURN uses the unit costs for work completed before the adoption of WSIP to estimate the reasonable cost of this work, without the extra costs due to the corrective notification backlog. Specifically, TURN uses an average of 2016-2018 unit costs to develop a forecast of $20.267 million for the Overhead Repair Program (MAT KAA), for example, which produces a reduction of $38.159 million from PG&E's forecast.[1156]

In reply, PG&E maintains that there is no evidence that inspection failures led to a cost-premium associated with the remediation work now required. PG&E acknowledges that under WSIP, PG&E issued corrective notices at approximately four times the average annual inspection find rate than in pre-WSIP years. But PG&E attributes the increase in work to WSIP being a more rigorous inspection program to address wildfire risks, not past inspection

[1153] TURN Opening Brief at 453.

[1154] TURN Reply Brief at 114.

[1155] TURN Opening Brief at 454.

[1156] TURN Opening Brief at 455.

failures. PG&E states that other factors contribute to cost increases, such as supply chain issues and inflationary pressures.[1157]

The Commission finds that, for purposes of evaluating its forecast, PG&E has not persuasively established its proposed pace of work. Given this uncertainty, the Commission directs PG&E to record costs for overhead and underground electrical distribution work in a two-way balancing account. A balancing account will protect ratepayers from paying the cost of untracked deferred work and allow PG&E the flexibility to perform the work it can cost-effectively perform. In this balancing account, PG&E shall separately account for any additional costs associated with difficult to access or remote areas.

By directing the above, PG&E should aim to move beyond crisis management to plan to hire sufficient employees to sustainably perform this work without paying overtime labor. Based on these general findings, we turn to the specific forecasts for the subcategories of this work below.

4.11.3. Overhead Equipment Replacement Expense Forecast (MWC KA)

PG&E requests an expense forecast for 2023 of $74.135 million for work tracked in Major Work Category, MWC KA Overhead Equipment Replacement.[1158] The Overhead Equipment Replacement Program involves the replacement of degraded or damaged equipment identified through PG&E's inspections.[1159] PG&E's expense forecast for the maintenance work tracked in

[1157] PG&E Reply Brief at 417 to 418, 422.

[1158] PG&E Opening Brief at 470 to 4734. (PG&E notes that this figure does not reflect any potential escalation based on the September 6, 2022 Update Testimony.)

[1159] PG&E Opening Brief at 418.

MWC KA Overhead Equipment Replacement includes of a forecast of $58.425 million in expense for activities tracked in MAT KAA Overhead Notification and Repair Program.[1160] As discussed above, PG&E bases its forecast for this work on an increased pace of work and 2019-2020 unit cost data.[1161] The forecast for MAT KAA Overhead Notification and Repair Program is contested.

TURN recommends reducing PG&E's 2023 expense forecast for MAT KAA Overhead Repair Program of $58.425 million by $38.1 million to $20.267 million.[1162] TURN bases its recommendation on an average unit costs for the period from 2016 to 2018.[1163] TURN uses this data because it contends that PG&E's forecast is based on unreasonable unit costs, which doubled and tripled, in 2019 and 2020 arising from the maintenance backlog caused by PG&E's insufficient inspection practices.[1164] TURN states that ratepayers should not be responsible for costs stemming from this maintenance backlog.[1165]

For the reasons discussed above in Sections 4.11.1 and 4.11.2, the Commission does not find PG&E's forecast reasonable because PG&E's forecasted pace of work and unit cost relied upon for its forecast are not persuasive. The Commission finds reasonable TURN's lower forecast of $20.267 million for MAT KAA Overhead Notification and Repair Program based on PG&E's historical data which reflects maintenance work performed without

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[1160] PG&E Reply Brief at 418.

[1161] PG&E Reply Brief at 417; PG&E Ex-04 at 13-30, for MAT 08J (Overhead Conductor Replacement), PG&E states that its 2020 forecast is lower than its 2023 forecast because in 2020, PG&E had to address other higher priority work. Cal Advocates Opening Brief at 184.

[1162] TURN Opening Brief at 451.

[1163] TURN Opening Brief at 455.

[1164] TURN Opening Brief at 451 to 452.

[1165] TURN Reply Brief at 113.

excessive costs. Accordingly, the Commission adopts a 2023 expense forecast for MAT KAA Overhead Notification and Repair Program of $20.267 million.

4.11.4. Overhead Preventive Maintenance and Equipment Repair (MWC 2A)

PG&E's capital forecast for MWC 2A Overhead Maintenance and Equipment Repair is $416.2 million for 2021, $267.2 million for 2022, $280.5 million for 2023, $305.3 million for 2024, $310.6 million for 2025, and $323.9 million for 2026.[1166] PG&E's MWC 2A Overhead Preventive Maintenance and Equipment Repair includes disputed forecasts tracked in the following MAT codes: Overhead Notifications (MAT 2AA), Bird Safe Installation and Replacement (MAT 2AB), Bird Safe Retrofit (2AC), Overhead Idle Facilities Removal (2AF), San Francisco Incandescent Street Light Replacement Program (MAT 2AG), Street Light Program (2AH), Facilities Removal; Overhead Capital Projects (MAT 2AP); Ceramic Post Insulator Replacement (MAT 2AQ); Non-Exempt Surge Arrester Replacement Program (MAT 2AR), and the Field Automation System Overhead Replacement (MAT 2AS).[1167] These disputed capital expenditure forecasts are addressed below.

4.11.4.1. Overhead Notifications Program (MAT 2AA)

PG&E tracks costs in MAT 2AA Overhead Notifications Program for work activities to replace and repair work of electrical overhead infrastructure issues identified by PG&E during patrols and inspections.[1168] PG&E forecasts $205.363 million in capital expenditures for 2023, which represents a

[1166] PG&E Ex-04 at 11-22. (PG&E's figures do not reflect PG&E Ex-33, the September 6, 2022 Update Testimony.)

[1167] PG&E Opening Brief at 476.

[1168] Cal Advocates Opening Brief at 192.

$25.4 million increase over PG&E's 2020 recorded capital expenditures of $179.951 million.[1169] PG&E states that this increase reflects work to resolve 19,548 notifications per year under the 2019 WSIP program from 2021-2023, which is an increase of approximately 33% over prior years, except for 2019.

Cal Advocates recommends reducing PG&E's proposal by $72.3 million to $133.0 million based on a lower unit cost of $6,806 per notification calculated using PG&E's data from 2016-2018 when PG&E relied less on outside contractors and overtime labor.[1170] Similarly, as discussed in Section 4.11.2, above, TURN recommends an even lower 2023 capital forecast for this program of $120.080 million and bases its recommendation on average recorded unit costs from 2016 to 2017 of $5,987 and $6,143, respectively.[1171] In addition, TURN notes that PG&E has not provided any evidence that higher priority work is more expensive to complete.[1172]

In response, PG&E reiterates arguments made in support of its forecast for work tracked in MAT KAA, including that the lower forecasts recommended by Cal Advocates and TURN do not reflect current market conditions or the planned work.[1173] In addition, PG&E states that its work includes activities in remote areas that cost more to complete.[1174]

The Commission finds that PG&E's forecast is not persuasive because PG&E has not addressed how its forecast reflects its plans to reduce costs by

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[1169] PG&E Opening Brief at 477.

[1170] Cal Advocates Opening Brief at 211.

[1171] TURN Opening Brief at 455.

[1172] TURN Reply Brief at 114.

[1173] PG&E Reply Brief at 420.

[1174] PG&E Reply Brief at 422.

hiring more employees and completing work with less costly overtime and contract labor. Instead, the Commission finds Cal Advocates' analysis persuasive, which relies on an average unit cost that includes 2018 and earlier data, whereas PG&E's forecast relies on later years which reflect costly contracts and overtime labor. Accordingly, for MAT 2AA Overhead Notifications Program, the Commission adopts Cal Advocates 2023 expense forecast of $133.0 million based on a lower unit cost of $6,806 per notification and less overtime labor and outside contractors.

4.11.4.2. Bird Safe Installations (MAT 2AB)

PG&E tracks capital expenditures for its Bird Safe Installation and Replacement Program in MAT 2AB. PG&E forecasts capital expenditures of $3.474 million in 2023 for MAT 2AB, which represents a $1.5 million increase from PG&E's 2020 capital expenditures for this program.[1175] Under this program, PG&E modifies electric distribution poles in response to bird incidents to minimize electrocutions of birds and avoid bird-related outages. PG&E also performs this work according to agreements with the United States Fish and Wildlife Service and internal standards.[1176]

PG&E explains that the increase in the costs and number of units in 2023 is higher than 2020 recorded costs due to increasing the priority of corrective notices or tags from those labeled priority E to tags labeled priority B, resulting in more work in shorter time. PG&E issues priority B tags when the condition of an asset is of moderate potential impact to safety or reliability and corrective action is required within three months from the date the condition is identified,

[1175] PG&E Opening Brief at 478; Cal Advocates Opening Brief at 194.

[1176] PG&E Ex-04 at 11-30.

whereas priority E tags require corrective action within 12 months from the date the condition is identified (or within six months if the tag creates a potential fire ignition risk in HFTD Tier 3).[1177] As a result, PG&E asserts that because it will be completing more higher priority tags, PG&E will necessarily be completing more work in a given year than it has historically. PG&E also explains that the number of units forecast for 2023 is based on compliance requirements and risk-based prioritization.[1178] According to Cal Advocates' summary of PG&E's workpapers, PG&E's pace of work for 2023 is nearly double PG&E's forecasted pace of work for 2020, with the unit cost of approximately $3,500, similar to 2020 for approximately 1,000 units per year projected in 2023.[1179]

Cal Advocates recommends reducing PG&E's bird safe corrective action 2023 capital expenditures from $3.5 million to $2.7 million based on reducing PG&E's estimated unit cost to $2,832 per notification due to the economies of scale Cal Advocates believes PG&E can achieve with a higher volume of work. Cal Advocates explains that PG&E had higher unit costs in 2019 and 2020 due to a reduced scope of work in those two years and reduced economies of scale. In 2023, PG&E anticipates a pace of work of nearly twice the pace of work of 2020. But Cal Advocates asserts that PG&E did not decrease its unit cost to account for its increased pace of work.

In response, PG&E states that Cal Advocates' estimate of how PG&E's unit costs for this work will change with the volume of work is speculative. PG&E asserts that its unit cost estimate is reasonable based on PG&E's recorded

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[1177] PG&E Opening Brief at 480.

[1178] PG&E Opening Brief at 480.

[1179] Cal Advocates Opening Brief at 195.

2019-2020 costs reasonably reflecting its projected costs in current market conditions.[1180]

The Commission finds PG&E's forecast for this work based on compliance requirements and risk-based prioritization, including increasing the priority of corrective notices or tags from those labeled priority E to tags labeled priority B.

Accordingly, the Commission adopts PG&E's requested 2023 capital expenditure forecast for MAT 2AB Bird Safe Installation and Replacement Program of $3.474 million. The Commission also adopts PG&E's requested capital expenditures of $3.023 million for 2021 and $3.841 million for 2022.

4.11.4.3. Bird Safe Retrofits (MAT 2AC)

PG&E tracks capital costs in MAT 2AC Bird Safe Retrofits Program for modifications to distribution poles as part of the annual program which requires selecting and retrofitting a minimum of 2,000 poles to support PG&E's commitment made to the US Fish and Wildlife Service to mitigate bird-related outages.[1181] PG&E states that this retrofit program is similar to the MAT 2AB Bird Safe Installations Program but it differs in that the program work is done in conjunction with PG&E's annual pole retrofit program.[1182] PG&E's capital expenditure forecasts are $3.432 million in 2021, $3.626 million in 2022, and $3.615 million in 2023.[1183]

Cal Advocates recommends reducing PG&E's request amount based on the lower Bird Safe Retrofits unit costs using 2017-2019 averages and a slower

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[1180] PG&E Reply Brief at 422 to 423.

[1181] PG&E Opening Brief at 479.

[1182] Cal Advocates Opening Brief at 196.

[1183] PG&E Opening Brief at 479.

pace of work based on 2019-2021 averages. Cal Advocates calculates a 2023 expenditure forecast of $1.9 million.[1184]

PG&E states that Cal Advocates reduced pace of work fails to consider PG&E's plan to increase the priority of corrective notices or tags as described at Section 4.11.4.2, herein, resulting in more work in a shorter time.[1185]

Based on PG&E's explanation supporting its proposed increased pace of work, the Commission finds PG&E's pace of work estimate reasonable and the resulting forecast for MAT 2AC reasonable. Accordingly, consistent with PG&E's 2023 forecast for the MAT 2AB Bird Safe Installation and Replacement Program, above, the Commission adopts a 2023 forecast for the MAT 2AC Bird Safe Retrofits Program of $3.615 million. The Commission also adopts PG&E's capital expenditure forecasts of $3.432 million in 2021 and $3.626 million in 2022.[1186]

4.11.4.4. Idle Facilities Removal (MAT 2AF)

Capital costs tracked in the MAT 2AF Idle Facilities Removal Program include costs for removing distribution infrastructure no longer necessary to serve customers.[1187] Removing idle facilities in HFTDs also reduces risk of ignition and supports System Hardening. For this program, PG&E requests capital expenditures as follows: $20.500 million in 2021, $2.732 million in 2022, and $2.726 million in 2023. PG&E's 2023 forecast represents a $2.2 million decrease from PG&E's 2020 capital expenditures for MAT 2AF Idle Facilities Removal Program.[1188]

[1184] Cal Advocates Opening Brief at 196-198.

[1185] PG&E Reply Brief at 423-425.

[1186] PG&E Opening Brief at 479.

[1187] PG&E Opening Brief at 481.

[1188] Cal Advocates Opening Brief at 198.

Cal Advocates recommends reducing PG&E's 2023 forecast for this program by $1.1 million to $1.6 million based on a lower unit cost. Cal Advocates does not recommend reducing PG&E's proposed pace of work for this program. Cal Advocates developed its recommended lower 2023 unit cost based on a unit cost derived from the Commission's authorized forecast in the PG&E's 2020 GRC, which Cal Advocates suggests is $4,888 per unit. Using several years of historical date (2016-2023), Cal Advocates states that PG&E's higher unit costs of $6,620 are due to PG&E's heavy use of contractors during years 2017-2018 and suggests that if the use of contractors, which are unreasonably expensive, is avoidable, PG&E should reduce its pace of work so that it employs fewer contractors and keeps unit costs lower.[1189]

PG&E responds that limiting PG&E's forecast based on Cal Advocates' lower pace of work and limited use of contractors potentially limits critical System Hardening in high-risk wildfire areas.[1190]

The Commission finds that limiting unit costs by relying on a forecast that reflects fewer contractors is a reasonable goal but that the pace of work for activities related to System Hardening must proceed in a timely manner. As a result, the Commission finds PG&E's requested capital expenditures forecast reasonable. Accordingly, the Commission adopts PG&E's requested capital expenditures of $20.5 million in 2021, $2.732 million in 2022, and $2.726 million in 2023 for MAT 2AF Idle Facilities Removal Program.

[1189] Cal Advocates Opening Brief at 198-199.

[1190] PG&E Reply Brief at 425-426.

4.11.4.5. Non-Wood Streetlights and Equipment with Access Issues (MAT 2AP)

PG&E's capital expenditures for two programs are tracked in MAT 2AP Non-Wood Streetlights and Equipment with Access Issues. PG&E states that its Non-Wood Streetlight Replacement Program includes activities to replaces poles installed prior to 2005 with an unacceptable level of corrosion. PG&E states that its Equipment with Access Issues Program is for activities to relocate equipment where line workers have identified hazards in accessing equipment as currently sited.[1191] For the two programs within MAT 2AP Non-Wood Streetlights and Equipment with Access Issues, PG&E capital expenditure request is $1.943 in 2021, $2.243 in 2022 and $2.243 million in 2023.[1192]

PG&E's forecast for 2023 is contested by Cal Advocates. PG&E requests $1.0 million in 2023 capital expenditures for the Non-Wood Streetlight Replacement Program, a $700,000 increase over 2020 recorded capital expenditures. Cal Advocates recommends 2023 capital expenditures forecast of $800,000 based on PG&E's average annual pace of spending from 2019-2021, including approximately $0 in 2020.[1193] PG&E responds that Cal Advocates' recommended forecast is inadequate and compromises PG&E's safety objectives for program.[1194]

The Commission finds PG&E fails to persuasively support its forecast for the Non-Wood Streetlight Replacement Program based on historical data of minimal costs in certain years and that Cal Advocates' recommendation of a

[1191] PG&E Opening Brief at 481.

[1192] PG&E Opening Brief at 481-482.

[1193] Cal Advocates Opening Brief at 205.

[1194] PG&E Reply Brief at 426 to 427.

lower forecast is reasonable. Accordingly, the Commission adopts a 2023 forecast of $800,000 for Non-Wood Streetlight Replacement Program, rather than PG&E's forecast of $1.0 million.

Regarding the other program tracked in MAT 2AP, the Equipment with Access Issues Program, Cal Advocates recommends reducing PG&E's 2023 capital expenditure forecast of $720,000 to an escalated annual average (2016-2018) resulting in a lower 2023 forecast of $350,000. Cal Advocates states that an average is appropriate because PG&E did not record costs to this program in 2019 or 2020 and, in addition, PG&E offers no convincing reasons supporting added work in this area beyond its historical average.[1195] PG&E responds that its forecast based on the amount of work it plans to accomplish based on known hazards identified by its engineers and planners.

The Commission finds that PG&E provides insufficient evidence to support this goal, especially based on historical costs and work. As a result, the Commission does not find PG&E has substantiated its requested forecast by a preponderance of the evidence. Instead, the Commission finds Cal Advocates recommendation convincing based on the evidence that PG&E did not record costs to reflect program work tracked in MAT 2AP for both 2019 and 2020. Accordingly, the Commission adopts 2023 capital expenditures forecast consistent with Cal Advocates' recommendation for the Equipment with Access Issues Program of $350,000. The Commission adopts a 2023 capital expenditure forecast for the two programs tracked in MAT 2AP of $800,000 plus $350,000 for a total forecast of $1.150 million for MAT 2AP Non-Wood Streetlights and Equipment with Access Issues.

[1195] Cal Advocates Opening Brief at 204.

4.11.4.6. Ceramic Post Insulators (MAT 2AQ)

PG&E tracks capital expenditures for replacing insulators manufactured prior to 1972 in MAT 2AQ Ceramic Post Insulator Replacement Program.[1196] PG&E states that these ceramic post insulators, that have been 50 years in service, must be replaced in a timely manner because failure to adequately insulate electric current presents both a safety and reliability risk.[1197] PG&E requests $5.821 million in 2023 capital expenditures to replace 2,093 ceramic post insulators.[1198] PG&E requests capital expenditures of $3.960 million in 2021 and $5.832 million in 2022. PG&E's 2023 request is a $3.0 million increase over PG&E's 2020 recorded capital expenditures.[1199] PG&E explains that the 2023 forecast is $3.0 million higher than 2020 recorded costs due to increased units from the HFTDs Tier 2 and Tier 3 increase in the MAT 2AR Non-Exempt Surge Arrester Replacement Program in 2021, and the plan to perform work independent of the surge arrestor replacement work in 2022. PG&E's unit cost forecast of $2,822 is based on the three-year average (2018-2020) for insulator replacement on an existing crossarm.[1200]

Cal Advocates recommends reducing PG&E's 2023 request to $1.1 million based on PG&E's average pace of work (2019-2021) of 396 units compared to PG&E's proposed pace of work in 2023 of 2,093 units. However, Cal Advocates presents no rationale for its proposed reduction and does not address PG&E's reason for the increase in replacements coupled to the surge arrestor program.

[1196] PG&E Opening Brief at 483.

[1197] PG&E Reply Brief at 428.

[1198] PG&E Opening Brief at 483.

[1199] Cal Advocates Opening Brief at 201-202.

[1200] PG&E Ex-04 at 11-29 to 11-30.

As a result, the Commission finds PG&E's request reasonable, because PG&E provides a convincing basis for its forecasted increase capital expenditures along with unit cost based on historical data. Accordingly, the Commission adopts PG&E's capital expenditure request for the MAT 2AQ Ceramic Post Insulator Replacement Program of $3.960 million in 2021, $5.832 million in 2022, and $5.821 million in 2023.

4.11.4.7. Field Automation System Overhead Replacement (MAT 2AS)

PG&E tracks capital costs in its Field Automation System Overhead Replacement Program (MAT 2AS) that involves work identified during a field job repair, including the replacement or installation of overhead facilities such as electric distribution conductors, components, structures and associated equipment constructed above the ground. PG&E requests a forecast of $830,000 in 2023 capital expenditures for this program based on 2,625 units,[1201] an increase of $610,000 over PG&E's 2020 expenditures.[1202] For this program, PG&E requests capital expenditures of $639,000 for 2021 and $831,000 for 2022.

Cal Advocates recommends a lower forecast based on its expected slower pace of work, consistent with the pace of work during 2017-2019 at 2,130 units, Cal Advocates calculate a 2023 capital expenditure forecast of $670,000.[1203] PG&E disagrees and maintains its forecast is supported by PG&E engineers' best estimate about how the system is functioning today and what replacement level will be needed to sustain performance.[1204]

[1201] PG&E Opening Brief at 484.

[1202] Cal Advocates Opening Brief at 203.

[1203] Cal Advocates Opening Brief at 203.

[1204] PG&E Reply Brief at 429.

Given PG&E's plans to increase maintenance of overhead electrical distribution maintenance, the Commission finds PG&E's plans to increase field automation system overhead replacement work to be reasonable. For this reason, the Commission finds PG&E's capital expenditure forecasts for its MAT 2AS Field Automation System Overhead Capital Program of $639,000 for 2021, $831,000 for 2022, and $830,000 for 2023 to be reasonable and adopts them.

4.11.4.8. Non-Exempt Surge Arrester Replacement (MAT 2AR)

PG&E states that surge arresters reduce the potential for release of electrical arcs, sparks, or other hot material during operation of electrical lines[1205] and are regulated by Public Resources Code Section 4292. According to PG&E, this statute and the associated regulations require certain surge arrestors to be clear of surrounding vegetation to reduce the risk of fire ignition, unless the equipment is exempt from this requirement.[1206] PG&E states that its Non-Exempt Surge Arrester Replacement Program replaces non-exempt surge arresters with exempt surge arresters and corrects abnormal electrical grounding issues, as necessary.[1207] This program is a mitigation for both the risk of wildfires and the failure of electric distribution lines.[1208]

PG&E states that it plans to complete non-exempt surge arrester replacements in high fire threat districts by 2022 and complete replacements system wide by 2026.[1209] PG&E requests capital expenditures of $17.759 million

[1205] PG&E Opening Brief at 485.

[1206] TURN Ex-09 at 34.

[1207] PG&E Opening Brief at 485.

[1208] PG&E Ex-04 at 11-27 to 11-28.

[1209] PG&E Ex-04 at 11-28.

in 2023 and $143.87 million total for 2022-2026 to replace 30,852 non-exempt surge arresters primarily in non-HFTD areas.[1210]

TURN recommends no funding for this program, unless the replacement work is in a HFTD or HFTD buffer areas. Alternatively, TURN recommends lowering the grounding-correction portion of the forecast by 20% and disallowing 100% of the expenditures related to tank-mounted grounding work, and 20% of the capital expenditures for corrections to non-tank-mounted surge arresters.[1211]

TURN states that replacing surge arresters in non-HFTD areas has limited safety benefits and PG&E should not prioritize this work.[1212] TURN states that outside of high fire threat districts and buffer areas, the risk posed by not replacing surge arresters, represented by a Risk Spend Efficiency value of 0.09, is low and only 4.88% of the risk in high fire-threat districts (a Risk Spend Efficiency of 1.88).[1213] TURN also contends that the Commission authorized a forecast of $72 million to perform surge arrester grounding work in the 2017 GRC of which PG&E spent only $0.7 million. Lastly, TURN questions whether a sufficient safety reason exists for replacing grounds.[1214]

In response, PG&E maintains that installing exempt surge arresters is a prudent mitigation of fire risk because when non-exempt surge arresters fail, the arrester can produce hot particles, including metals, capable of starting a fire in the presence of fuel whereas exempt surge arresters reduce the potential for

[1210] PG&E Opening Brief at 485.

[1211] TURN Opening Brief at 456; TURN Ex-09 at 37.

[1212] TURN Opening Brief at 452.

[1213] TURN Opening Brief at 452.

[1214] TURN Opening Brief at 457.

release of electrical arcs, sparks, or hot material during operation.[1215] PG&E states further that vegetation management under poles with non-exempt equipment reduces risk, but it does not eliminate it because wind can blow the particles outside the perimeter that is cleared as required by Public Resources Code Section 4292.[1216]

The Commission considers risk spend efficiencies as part of evaluating the relative risk reduction of mitigation measures. The risk reduction benefit of replacing non-exempt surge arrestors in non-HFTD areas, based on RSEs, appears relatively low. Nevertheless, RSEs are only one component to be considered and, after taking all the evidence into consideration, the Commission finds PG&E's Non-Exempt Surge Arrester Replacement Program forecast to be reasonable based on the likelihood of reducing this known risk in the non-HFTDs. Accordingly, the Commission adopts PG&E's 2023 Non-Exempt Surge Arrester Replacement Program (MAT 2AR) capital expenditure forecast of $17.759 million. The Commission also adopts PG&E's capital expenditure request of $88.859 million in 2021 and $16.804 million in 2022.

4.11.5. Underground Equipment Replacement (MWC 2B)

The following two underground equipment replacement programs are disputed.

4.11.5.1. Underground Notifications (MAT 2BA)

PG&E states that it corrects abnormal maintenance conditions in underground facilities through the MAT 2BA Underground Notifications Program to improve system reliability and safety, and to ensure regulatory

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[1215] PG&E Ex-04 at 11-27.

[1216] PG&E Reply Brief at 432-433.

compliance.[1217] As with PG&E's MAT 2AA Overhead Notifications Program the Underground Notifications Program involves replacing and repairing electrical underground infrastructure issues identified by PG&E personnel during patrols and inspections.[1218] PG&E requests capital expenditures of $46.680 million in 2021, $46.391 million in 2022, and $47.807 million in 2023 capital expenditures for the Underground Notifications program.[1219] PG&E's 2023 request is a $9.9 million increase from PG&E's 2020 capital expenditures.[1220] PG&E attributes the increase to a higher number of units, as well as an increase in unit cost.[1221]

Cal Advocates recommends reducing PG&E's 2023 request MAT 2BA Underground Notifications from $47.8 million to $36.4 million based on a lower average unit cost derived from PG&E's average annual unit cost from 2016-2018 of $20,036 in 2023 dollars instead of PG&E's unit cost of $26,317. Cal Advocates states that a reduced unit cost is reasonable because PG&E should be managing its workload to avoid using the additional contract and overtime labor that PG&E used in 2019 and 2020.[1222]

In response, PG&E reiterates that its request is reasonable because it reflects current market conditions, or the work plan presented in the forecast. In addition, PG&E adds that the unit costs for this work have been impacted by (1) additional work for regulatory tags (F Priority), which were identified during the 2014-2017 timeframe to be completed in the 2018-2020 timeframe, and (2) an

[1217] PG&E Opening Brief at 490.

[1218] Cal Advocates Opening Brief at 206.

[1219] PG&E Opening Brief at 490.

[1220] Cal Advocates Opening Brief at 206.

[1221] Cal Advocates Opening Brief at 207.

[1222] Cal Advocates Opening Brief at 207.

increase in the cost of work on primary enclosures (larger enclosures that contain high-voltage cables), as opposed to secondary enclosures (smaller enclosures that contain low-voltage cables).[1223]

Based on these additional factors, the Commission finds PG&E's request for capital expenditures for MAT 2BA Underground Notifications Program of $46.680 million in 2021, $46.391 million in 2022, and $47.807 million in 2023 to be persuasive and reasonable, and adopts it.

4.11.5.2. Underground Critical Operating Equipment (MAT 2BD)

PG&E tracks costs in MAT 2BD Underground Critical Operating Equipment Program for work to perform corrective maintenance on equipment including reclosers, regulators, and switches.[1224] For this program, PG&E requests capital expenditures of $6.573 million in 2021, $6.354 million in 2022, and $6.926 million in 2023[1225] based on approximately 144 notifications per year.[1226] PG&E states that its 2023 forecast represents a $0.7 million decrease from its 2020 capital expenditures due to a lower unit cost.[1227] PG&E's unit cost is based on the 2018-2019 two-year average of the find rate plus additional units for open or pending jobs.[1228]

Cal Advocates recommends reducing PG&E's 2023 forecast for this program from $6.9 million to $5.6 million based on reducing the pace of this

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[1223] PG&E Reply Brief at 435 to 436.

[1224] PG&E Opening Brief at 490; Cal Advocates Opening Brief at 208.

[1225] Cal Advocates Opening Brief at 208.

[1226] PG&E Reply Brief at 437.

[1227] PG&E Opening Brief at 490.

[1228] PG&E Reply Brief at 437.

program to the most recent three full years of data that were available, from 2018-2020. During that time the PG&E completed 116 notifications per year.[1229]

In response, PG&E states that performance of this work was negatively impacted by the COVID-19 pandemic because this program has a lower priority than other maintenance work. As a result, PG&E suggests that including the COVID-impacted 2020 work volume in an average to determine the 2023 unit forecast results in an understated forecast not reflective of PG&E's work plans. In addition, PG&E states that the 144 units PG&E forecasts in 2023 is like the recorded number of units in 2016, 2017 and 2018.[1230]

The Commission finds PG&E's forecast to be reasonable and adopts its forecast for the MAT 2BD Underground Critical Operating Equipment Program of $6.573 million in 2021, $6.354 million in 2022, and $6.926 million in 2023.

4.11.5.3. Street Light Program (MAT 2AH)

PG&E tracks work in MAT 2AH LED Streetlight Conversion Program for replacing high-pressure sodium vapor streetlights with light-emitting diode (LED) illuminated streetlights.[1231] PG&E requests capital expenditures of $1.028 million in 2021, $2.116 million in 2022, and $7.075 million in 2023 capital for the LED Streetlight Conversions Program.[1232] This 2023 forecast represents a $4.5 million increase from PG&E's 2020 recorded expenditures.[1233]

PG&E states that this program improves system reliability and public safety by reducing streetlight burnouts and by producing more consistent light

[1229] Cal Advocates Opening Brief at 208-209.

[1230] PG&E Reply Brief at 436-437.

[1231] PG&E Ex-04 at 11-25.

[1232] PG&E Ex-04 at 11-26.

[1233] Cal Advocates Opening Brief at 199.

output throughout their service life than high-pressure sodium vapor bulbs do. PG&E also states that LED fixtures last for approximately 20 years, whereas high-pressure sodium vapor bulbs last for approximately four to five years.[1234]

PG&E states that in the 2020 GRC, the Commission authorized a forecast to convert PG&E's remaining conventional and decorative streetlights by the end of 2019 but approximately 15,000 decorative streetlights still need to be converted. PG&E states that this delay was due to an "incremental facility charge" that customers were not willing to incur.[1235] PG&E states that this incremental facility charge will be reduced in half by 2022 and eliminated by 2023, at which point PG&E will be able to complete the remaining decorative streetlight conversions.[1236]

Cal Advocates recommends reducing PG&E's 2023 capital expenditure forecast for this program by $0.4 million based on PG&E's pace of work between 2019-2021. Cal Advocates also questions the basis for PG&E's projection of increased demand and the reason increasing the pace of work.[1237] However, Cal Advocates acknowledges that there may be greater demand for the LED Streetlight Conversions program once incremental facility charges expire in 2023.[1238]

The Commission finds PG&E's forecast to be reasonable because it is based on a sufficient correlation between PG&E's estimated demand with the decrease in the facility charge. Accordingly, the Commission adopts PG&E capital

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[1234] PG&E Ex-04 at 11-25 to 11-26.

[1235] PG&E Ex-04 at 11-26.

[1236] PG&E Ex-04 at 11-26.

[1237] Cal Advocates Opening Brief at 200.

[1238] Cal Advocates Opening Brief at 200.

expenditure forecast for MAT 2AH LED Streetlight Conversion Program of $1.028 million in 2021, $2.116 million in 2022, and $7.1 million in 2023 forecast.

4.11.5.4. San Francisco Incandescent Streetlight Replacement (Capital MAT 2AG)

PG&E explains that the San Francisco Incandescent Streetlight Replacement program involves replacing the remaining outdated incandescent streetlights that PG&E owns and operates in San Francisco. PG&E is not currently planning to perform any work in this program in 2020-2022 because of the City and County of San Francisco's five-year paving moratorium, which went into effect in late 2017. After that moratorium expires, PG&E requests capital expenditures of $2.5 million in 2023 and $2.6 million in 2024 to complete the program.[1239] PG&E's forecast is based on replacing the remaining 49 incandescent streetlights starting in 2023.[1240]

Cal Advocates recommends a forecast of $2.4 million in 2021 and does not contest PG&E's capital expenditure for this program in 2022-2023.[1241] However, PG&E did not plan to perform any work for this program in 2021. Accordingly, the Commission finds it reasonable to adopt $0 in capital expenditures for 2021 for MAT 2AG San Francisco Incandescent Streetlight Replacement. In addition, the Commission finds PG&E's forecast for this program of $0 for 2022, $2.5 million in 2023, and $2.6 million in 2024 to be reasonable and adopts it.

4.12. Pole Asset Management

PG&E's electric distribution system includes approximately 2.3 million wood poles. PG&E tracks work in its Pole Asset Management Program to

[1239] PG&E Ex-04 at 11-25.

[1240] PG&E Ex-04 at 11-25.

[1241] Cal Advocates Opening Brief at 205.

maintain the safety and reliability of wood pole assets through comprehensive inspection and repair/replacement programs.[1242] Regarding the uncontested forecasts for 2023 expense and 2021, 2022, and 2023 capital expenditures for PG&E's Pole Asset Management, the Commission finds those amounts to reasonable.[1243] The disputed aspects of the Pole Asset Management Program are addressed below.

4.12.1. Prior Pole Inspection and Replacement

Cal Advocates and TURN contend that PG&E historically has not adequately inspected and replaced (when necessary) distribution poles under PG&E's Pole Replacement Program and that PG&E has a history of deferring pole asset management capital projects that had previously been authorized by the Commission.[1244] As a result, Cal Advocates recommends disallowing costs to account for these historical deficiencies and excluding higher replacement costs that could have been avoided.[1245] Similarly, TURN states that PG&E's inspection process prior to the Wildfire Safety Inspection Program was deficient, which has directly led to the backlog that has generated unit costs that are well above the historical norm.[1246]

In response, PG&E claims that the high volume of pole maintenance/replacement items is due to PG&E applying stricter inspection criteria in order to ensure that wildfire risks were being addressed

[1242] PG&E Opening Brief at 492-493.

[1243] The uncontested expense and capital expenditure forecasts are set forth at Appendix A of PG&E's Opening Brief at A-12 and A-22.

[1244] PG&E Opening Brief at 440; TURN Opening Brief at 460-461; Cal Advocates Reply Brief at 52-53.

[1245] Cal Advocates Reply Brief at 53.

[1246] TURN Opening Brief at 460-461.

sufficiently.[1247] PG&E states that Cal Advocates and TURN fail to acknowledge that many factors (such as extreme weather and environmental conditions, intrusive insects and rot, third-party-caused damage, etc.) that cause poles to degrade or fail are dynamic, unpredictable, and often sudden.

Following the unprecedented number of wildfires in PG&E's service territory beginning in 2017,[1248] PG&E adopted the Wildfire Safety Inspection Program in 2019 to "expand inspections of poles and associated equipment in HFTD areas on an accelerated and enhanced basis."[1249] As a result of this enhanced inspection, PG&E is faced with an increased backlog of poles identified for remediation.[1250]

As the Commission stated in D.19-05-037, PG&E has always had an obligation to inspect its electric system with sufficient thoroughness and regularity so as to prevent its system from igniting wildfires. Based on PG&E's deferral of pole replacement work since 2003,[1251] the Commission finds that PG&E's deferral of pole replacement work in the last twenty years has contributed to PG&E's current backlog of this work. PG&E's enhancement of its inspection program was long overdue. Although the enhanced inspection may have contributed to PG&E's pole replacement backlog, the Commission finds that PG&E's backlog occurred over decades, not suddenly.

Against this backdrop, we address PG&E's forecasts for pole replacements below.

[1247] PG&E Reply Brief at 441.

[1248] D.23-01-005 at 5 to 9.

[1249] PG&E Ex-04 at 10-5.

[1250] TURN Opening Brief at 445.

[1251] Cal Advocates Ex-05 at 21-30.

4.12.2. Pole Replacement Programs (MAT 07D, MAT 070, and MAT 07C)

PG&E tracks capital expenditure costs in MAT 07D Pole Replacement Program for work to replace poles identified as deteriorated, degraded, or damaged. PG&E requests a capital forecast of $311.884 million for 2021, $366.453 million for 2022, and $379.514 million for 2023 for MAT 07D Pole Replacement Program. PG&E calculates its pole replacement unit cost by first determining the unit cost of each of PG&E's 23 geographical divisions in its service territory (using recorded costs for 2018-2020), and then multiplying those unit costs by the number of forecast pole replacements in each geographic area.[1252]

PG&E's Pole Asset Management also includes the intrusive inspection and reinforcement of wood poles, the Pole Replacement Program, the Pole Loading Program, which is tracked in MAT 07O, and the replacement of tree attachments, which is tracked in MAT 07C,[1253] and joint utilities coordination.[1254]

PG&E contends that its pole replacement unit cost is reasonable for several reasons. PG&E states that its three-year average takes into consideration annual fluctuations with an upward trend and existing market conditions, including higher labor and non-labor costs, disposal costs, and environmental/permitting costs. PG&E also states the increase of pole replacement costs in recent years can be attributed to the locations of the pole replacements. PG&E states that it has appropriately prioritized pole replacements in HFTD Tier 2 and Tier 3 areas, where the poles at times are not accessible with bucket trucks and require the use

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[1252] PG&E Reply Brief at 444.

[1253] PG&E Opening Brief at 495.

[1254] Cal Advocates Opening Brief at 209.

of more expensive equipment, including helicopters, large cranes, or other heavy equipment, which adds significant cost to those replacements.[1255]

Cal Advocates recommends a reduced 2023 capital forecast for MAT 07D of $347.679 million based on a different pole replacement unit cost.[1256] Cal Advocates uses the same methodology for determining this unit cost as PG&E except that Cal Advocates bases its unit cost on 2018 data. Cal Advocates then escalates the 2018 unit costs using the Construction Cost Escalation Rates that PG&E provides for Electric Distribution capital projects. Using these electric distribution construction cost escalation rates for each of PG&E's 23 geographical divisions, Cal Advocates escalates each of the 2018 unit costs year by year to produce the unit costs for the year 2023. Using these revised 2023 pole replacement unit costs, Cal Advocates multiplies those unit costs by the same number of pole replacements that PG&E forecast for that year.[1257]

Cal Advocates uses the unit cost for 2018 in its forecast for several reasons. First, pole replacement unit costs increased dramatically in 2019. Second, Cal Advocates contends that if PG&E had inspected its electric distribution more thoroughly earlier, as later mandated, and had not deferred authorized pole replacement capital projects (beginning not later than its TY 2003 GRC), PG&E would likely have discovered failing poles much earlier, with sufficient time and opportunity to replace them in a normal (i.e., non-emergency) manner. Third, under that scenario, PG&E would not need to hire additional contract workers

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[1255] PG&E Reply Brief at 445.

[1256] Cal Advocates Opening Brief at 209 and 214.

[1257] Cal Advocates Opening Brief at 218.

(with additional overtime) for MWC 07 capital projects.[1258] Cal Advocates methodology produces a lower unit cost.

As discussed above, TURN contends that the number of poles PG&E has marked for remediation exceeds what would be expected from the current inspection process and is instead due to a failure on PG&E's part to implement prudent inspection practices.[1259] As a remedy, TURN also proposes a different unit cost. TURN's recommended unit cost relies on 2016-2017 data as the last "business as usual" years before the number of units remediated almost doubled, which TURN attributes to a significant number of contract or overtime hours. TURN then estimated the increased cost of heavy equipment based on $4,300 hourly costs for helicopters, at two pole replacements an hour and an estimate of 1,498 poles in hard to access locations. TURN also includes $403 in its unit costs to account for the increased use of heavy equipment. The result is a unit costs of $18,079 for 2023 as the basis for TURN's forecast compared to PG&E's $23,076 unit cost for 2023.[1260]

The parties do not dispute PG&E's forecast for the number of electric distribution poles needing replacement. The Coalition of California Utility Employees recommends approving PG&E's pole replacement program proposal and reject Cal Advocates' and TURN's arguments concerning unit costs. In support of its recommendation, Coalition of California Utility Employees indicates that PG&E's proposal has a revenue requirement with net present value

[1258] Cal Advocates Reply Brief at 53.

[1259] TURN Reply Brief at 115.

[1260] TURN Opening Brief at 465.

of $10.744 billion for 2022-2031, which is 7% of the cost of the wildfires in California in 2018 of $149 billion.[1261]

Cal Advocates and TURN base their proposed pole replacement unit cost on data from years prior to the dramatic increase in the unit cost for pole replacement. Such costs rose by approximately 48% from about $19,773 per unit in 2018 to about $29,379 in 2019,[1262] arguably due to increased costs associated with accelerating the replacement of electric distribution poles. Cal Advocates and TURN argue the use of pre-2019 data is reasonable because accelerating pole replacements would not have been as necessary had PG&E not deferred pole replacements in the last two decades. On the other hand, PG&E contends that its forecast based on data from 2018 to 2020 is reasonable because it reflects current conditions, and current costs should be adopted because they are not in PG&E's control. In this case, the Commission finds that PG&E has had the ability to reduce its unit costs for this work. The record shows that higher 2019-2020 costs forecast by PG&E were impacted by the need to hire additional contractors and increased overtime as a result of the need to acceleration of work in HFTDs.[1263] As a result, consistent with the Commission's finding in the last adjudicated rate case in 2014, the Commission adopts a forecast based on a pole replacement unit cost based on 2018 data prior to the time period when the cost of pole replacements increased due to PG&E having to accelerate its pole replacement work to eliminate a long-standing backlog. Accordingly, the Commission adopts Cal Advocates' 2023 capital forecasts for the Pole Replacement Programs, shown below, including $337.48 million for MAT 07D, $7.18 million for MAT 07O and

[1261] CUE Ex-02 (Rebuttal Testimony) at 5 to 11.

[1262] TURN Opening Brief at 464 (Table 47).

[1263] Cal Advocates Reply Brief at 53.

$3.02 million MAT 07C. Cal Advocates' capital forecast for 2023 does not include costs tracked in the Wildfire Mitigation Plan Memorandum Account because PG&E does not track costs for Pole Asset Management in the Wildfire Mitigation Plan Memorandum Account after 2022.[1264]

Table: 4-J [1265]
Pole Replacement Programs (Mats 07D, 07O And 07C):
PG&E's Capital Forecast And Parties Recommended Reductions ($000s)(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
MAT 07D							
PG&E	$238,714	$301,007	$355,298	$368,381	$388,115	$387,889	$388,355
Cal Advocates				$(30,901)			
TURN			$(76,660)	$(79,764)			
MAT 07O							
PG&E	$11,114	$10,877	$7,852	$7,837	$8,600	$9,391	$10,210
Cal Advocates				$(657)			
MAT 07C							
PG&E	$87	$-	$3,303	$3,296	$3,500	$3,709	$3,924
Cal Advocates				$(276)			
Cal Advocates (b)		$(155,605)	$(227,390)				
Total Forecast	$249,916	$311,884	$366,453	$379,514			
Cal Advocates Total Rec. Reduction		$(155,605)	$(227,390)	$(31,83)			
TURN Total Rec. Reduction			$(76,660)	$(79,764)			

(a) PG&E-17, p. 12-14, Table 12-5, lines 1-3 (PG&E's 2020-2026 recorded and forecast costs); p. 12-15, Table 12-6, lines 1 and 4; p. 12-4, Table 12-2, lines 1-3 (Parties' recommendations).

(b) Cal Advocates' recommended reductions for 2021 and 2022 are related to PG&E's Pole Replacement Program and are not allocated by MAT.

[1264] Cal Advocates Opening Brief at 214.

[1265] PG&E Reply Brief at 440 (Table 4-30).

4.12.3. Pole Replacement Forecasts for 2021 and 2022

Cal Advocates recommends removing from rate base PG&E's recorded and forecast pole replacement capital expenditures that are simultaneously being tracked in the Wildfire Mitigation Plan Memorandum Account until the Commission has found those costs to be reasonable.[1266] PG&E claims that "it is not precluded from including in rate base costs tracked in memorandum accounts for purposes of computing its test year and post-test-year revenue requirements in a GRC."[1267] In addition, PG&E states "[t]here is no reasonable dispute that these recorded plant costs are currently used and useful."[1268]

Since the specific amounts at issue require a reasonableness review prior to PG&E's recovery, the Commission does not authorize cost recovery of amounts in memorandum accounts prior to that review. The Commission will review such costs through the processes already established to review them outside this GRC. The Commission directs PG&E to remove capital expenditures from the revenue requirements requested herein that are recorded any memorandum account or balancing account subject to Commission reasonableness review, such as the Wildfire Mitigation Plan Memorandum Account. This topic is further addressed in Section 16, herein.

4.13. Overhead and Underground Asset Management and Reliability

PG&E's Overhead Asset Management program involves overhead asset replacement for deteriorated overhead conductor and switches. PG&E's Underground Asset Management program addresses asset replacement for

[1266] Cal Advocates Opening Brief at 212 to 214; Cal Advocates Reply Brief at 53.

[1267] PG&E Ex-23 (Rebuttal) at 15-3.

[1268] PG&E Ex-23 (Rebuttal) at 15-3; PG&E Opening Brief at 827.

underground assets, including primary underground distribution cable, switches, vaults, enclosures, and conduits. In addition to these asset replacement programs, PG&E implements a reliability program that involves providing additional distribution protection device zones or automated switching equipment to reduce or mitigate the number of customers impacted by future outages. PG&E tracks the capital expenditures for this work in three Major Work Categories: MWC 08 Electric Distribution Overhead Asset Replacement, MWC 49 Distribution Circuit Zone Reliability and MWC 56 Electric Distribution Underground Asset Replacement. The Commission addresses each of these Major Work Categories below.

4.13.1. Electric Distribution Overhead Asset Replacement (Capital MWC 08)

Regarding the uncontested capital expenditures requests for MWC 08 Electric Distribution Overhead Asset Replacement, the Commission finds the uncontested amounts requested for MWC 08 to be reasonable.[1269] The disputed aspects of PG&E's request related to MWC 08 Electric Distribution Overhead Asset Replacement are discussed below.

4.13.1.1. Overhead Conductor Replacement Program (MAT 08J)

Through PG&E's MAT 08J Overhead Conductor Replacement program, PG&E proposes to proactively replace overhead conductor in non-HFTD areas to address elevated rates of downed wires, deteriorated or damaged conductors, and to improve system safety, reliability, and integrity.[1270] PG&E explains that wires replaced in HFTDs are replaced through PG&E's System Hardening

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[1269] These uncontested capital expenditure requests are set forth at Appendix A of PG&E's Opening Brief at A-17 and A-25.

[1270] PG&E Opening Brief at 505.

Program (MAT 08W).[1271] PG&E requests capital expenditures of $41.2 million in 2021, $32.7 million in 2022, and $43.0 million in 2023 for this program.[1272] PG&E's request represents a $26.4 million increase over PG&E's 2020 capital expenditures. PG&E states that the cost increase results from a lower volume of 2020 work than planned, as PG&E in 2020 allocated resources to higher priority work and wildfires support programs.[1273] PG&E replaced 29.4 miles of conductor in the Overhead Conductor Replacement program in 2020, and forecasts 73.6 miles in 2023.[1274]

Cal Advocates recommends a lower forecast for 2023 of $17.2 million for MAT 08J Overhead Conductor Replacement because, according to Cal Advocates, PG&E's proposed 2021-2023 pace/amount of forecasted work is excessive and not consistent with PG&E's recent historic trends. In addition, Cal Advocates questions whether PG&E has the capacity to expand the pace of work for its non-HFTD Overhead Conductor Replacement program, while at the same time suggesting it will ramp up the same HFTD wildfire support programs that reduced the pace of the MAT 08J Overhead Conductor Replacement in 2019-2020. Cal Advocates proposes a reduced forecast based on PG&E's pace of replacing 44 miles of conductor per year work in 2021, which is the approximate level PG&E is projected to meet at end of 2021, and a pace of 29 miles in 2022- 2023, which is PG&E's average pace of work from 2019-2021.

AARP recommends a forecast for 2023 of $14.157 million based on the three-year average spent from 2018–2020 until wildfire risk spending slows, or

[1271] Cal Advocates Opening Brief at 223.

[1272] PG&E Opening Brief at 505.

[1273] Cal Advocates Opening Brief at 223.

[1274] Cal Advocates Opening Brief at 223-224.

until data is collected which indicates that pre-emptive conductor replacement delivers benefits in excess of cost.[1275] AARP also contends that the risk and cost-effectiveness for reconductoring work by PG&E outside of HFTD areas is low.[1276]

In response, PG&E asserts that the recommendations by Cal Advocates, TURN, and AARP should be rejected for several reasons. First, basing funding for this program on the prior resource-constrained pace of work that occurred from 2019-2021 would be imprudent because the proposed pace of work is necessary to keep the electric distribution system reliable.[1277] According to PG&E, its proposed replacement level is supported by a 2018 study completed by the National Electric Energy Testing Research and Applications Center that concluded a significant annual increase of total conductor replacements would be needed to avoid increasing outage levels.[1278] Second, PG&E claims that its forecasted replacement is achievable.[1279]

As presented by PG&E, its Overhead Conductor Replacement program focuses on replacing overhead conductor with the highest conductor and splice failure rates.[1280] As such, the Commission finds that PG&E's replacement rate and forecast to be reasonable based on avoiding safety hazards and outages and ensuring reliability. Accordingly, for PG&E's MAT 08J Overhead Conductor Replacement program, the Commission adopts PG&E's capital expenditure

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[1275] AARP Opening Brief at 30-33.

[1276] AARP Opening Brief at 30-33.

[1277] PG&E Reply Brief at 451.

[1278] PG&E Reply Brief at 451.

[1279] PG&E Reply Brief at 452.

[1280] PG&E Reply Brief at 453.

request for 2021 of $41.2 million, 2022 of $32.7 million, and 2023 of $43.0 million. The Commission also finds it reasonable to require more certainty regarding the reliability of PG&E's service. For this reason, the Commission requires PG&E to provide data regarding outage levels and the useful lives of the equipment being replaced to support future programs impacting system reliability, including this one, in its 2027 GRC.

4.13.1.2. Overhead Switch Replacements (Capital MAT 08S)

PG&E tracks work in MAT 08S Overhead Switch Replacement Program to replace switches installed between 1950 and 1970, known as "grasshopper switches," for the purpose of minimizing potential safety issues during switching operations and improving reliability.[1281] PG&E requests a capital expenditures of $0.925 million in 2021, $0.949 million in 2022, and $0.975 million in 2023.[1282] PG&E's request for 2023 represents a $0.5 million increase over PG&E's 2020 recorded capital expenditures for MAT 08S Overhead Switch Replacement Program. PG&E bases its forecast on completing 30 replacements per year from 2021-2023.[1283]

Cal Advocates recommends reducing the 2023 request by approximately $0.7 million to $0.3 million based on a lower replacement rate of nine per year. Cal Advocates' bases its recommended replacement rate on PG&E's 2021 rate of 12 replacements per year and the approximate average pace of work from 2019-2021.[1284] In addition, Cal Advocates contends that PG&E has not

[1281] PG&E Opening Brief at 509.

[1282] PG&E Opening Brief at 509.

[1283] Cal Advocates Opening Brief at 225.

[1284] Cal Advocates Opening Brief at 226.

demonstrated how PG&E determined the rate of 30 replacements per year or reasons for increasing the replacement rate and argues that this equipment is still functional and can be replaced at the end of its useful life.[1285]

In response, PG&E states that its proposed replacement rate is consistent with the replacement rate agreed upon in the last two GRCs that settled.[1286] The Commission finds previous settlement to be an insufficient evidentiary basis for establishing a replacement rate that departs from the estimate of this equipment's useful life. Accordingly, the Commission adopts Cal Advocates 2023 capital forecast of $0.3 million for the PG&E's MAT 08S Overhead Switch Replacement Program and the Commission adopts the uncontested amounts of $0.925 million of 2021 and $0.949 million for 2022.

4.13.2. Distribution Circuit Zone Reliability (Capital MWC 49)

PG&E's tracks costs in MWC 49 Distribution Circuit Zone Reliability for work that focuses on achieving reliability improvements through the following targeted measures: (1) performance of base reliability work including work to improve service to customers; (2) installation of overhead protective devices including fuses; (3) installation of distribution system line reclosers; (4) installation of FuseSaver devices; and (5) installation of Fault Location, Isolation and Service Restoration (FLISR) systems.[1287]

Some aspects of forecasts for expense and requests for capital expenditures related to MWC 49 Distribution Circuit Zone Reliability are uncontested and the

[1285] Cal Advocates Opening Brief at 226.

[1286] PG&E Reply Brief at 454.

[1287] PG&E Opening Brief at 510 to 511.

Commission find those amounts to be reasonable.[1288] Cal Advocates contests the forecast for MAT49C Overhead Fuses, and the Commission addresses this dispute below.

4.13.2.1. Overhead Fuses (MAT 49C)

PG&E tracks cost in MAT 49C Overhead Fuse program for work to install new line fuses on overhead distribution circuits in order to limit the impact and scope of outages and the number of customers affected.[1289] PG&E forecasts installing approximately 100 new sets of overhead fuses per year on tap lines to prevent mainline outages at $1.560 million in capital in 2023.[1290] PG&E states that its 2023 request represents a $1.3 million increase over PG&E's 2020 capital expenditures.[1291]

Cal Advocates recommends reducing PG&E's forecast for MAT 49C Overhead Fuse program to the level of the 2020 program or to $0.3 million in 2023. Cal Advocates bases its reduction on PG&E having installed 79 fuses in 2021 and estimating that it replaced 129 fuses each in 2022 and 2023.
Cal Advocates' recommendation is based on the approximate average pace of work from 2019-2021 of 13 installations per year.[1292]

In response, PG&E states that Cal Advocates' extrapolation of PG&E's pace of work at 13 units based upon partial 2021 costs is inconsistent with PG&E's actual pace of work for 2021 of 97 fuses installed.[1293] PG&E plans to

[1288] The uncontested expense and capital expenditure forecasts are set forth at Appendix A of PG&E's Opening Brief at A-17 and A-25.

[1289] PG&E Opening Brief at 511.

[1290] PG&E Opening Brief at 511.

[1291] Cal Advocates Opening Brief at 226.

[1292] Cal Advocates Opening Brief at 226 to 227.

[1293] PG&E Reply Brief at 456.

increase this pace going forward during this rate case period. PG&E explains that the lower 2018-2020 pace of work was primarily driven by its focus on wildfire mitigation efforts. Since then, PG&E states that it has returned to a pace of work similar to its 2016-2017 unit completion rate, as reflected in its 2021 pace of work.[1294]

With the evidence of a previously achieved rate of replacement for this equipment, the Commission finds PG&E's forecast for 2023 to be reasonable and consistent with promoting safety and reliability. Accordingly, the Commission adopts PG&E's 2023 capital forecast for PG&E's overhead fuse program of MAT 49C Overhead Fuse program of $1.560 million. The Commission adopts the uncontested capital expenditures request of $0.882 million in 2021 and $1.5 million in 2022 for MAT 49C Overhead Fuse program.

4.13.3. Electric Distribution Underground Asset Replacement (MWC 56)

PG&E's electric underground distribution system consists of primary distribution cable and associated switches, vaults, enclosures, conduits, splices, cable connectors, and other equipment. PG&E states that capital work in the Underground Asset Management program primarily consists of replacing underground cables and switches.[1295] Regarding the uncontested forecasts for expense and capital expenditures for electric distribution underground asset replacement tracked in MWC 56 Electric Distribution Underground Asset Replacement, the Commission find those amounts to be reasonable.[1296]

[1294] PG&E Reply Brief at 456-457.

[1295] PG&E Opening Brief at 512.

[1296] The uncontested expense and capital expenditure forecasts are set forth at Appendix A of PG&E's Opening Brief at A-17 and A-25.

Cal Advocates recommends a forecast reduction for the four programs within MWC 56 Electric Distribution Underground Asset Replacement, as discussed below.

4.13.3.1. Reliability Related Cable Replacement (MAT 56A)

PG&E forecasts $36.976 million in 2023 for replacing underground distribution cable,[1297] which is work tracked in MAT 56A Reliability Related Cable Replacement program. PG&E requests capital expenditures of $38.013 million in 2021 and $39.556 million in 2022. PG&E states that its 2023 request represents a $19.0 million increase from PG&E's 2020 capital expenditures.[1298] PG&E plans to increase the replacement rate to maintain "a steady proactive replacement of aging cables" and to make up work deferred in 2019 and 2020 by replacing 25.7 miles in 2021, 21.3 miles in 2022, and 17.5 miles 2023.[1299] PG&E bases this forecast on the cables' reliability performance, age, and type or a combination of these factors and other influences.

Cal Advocates recommends a lower forecast for 2023 capital expenditures of $28.3 million based on reducing PG&E's rate of replacement to its 2018-2020 average.

In response, PG&E contends that its proposed pace is needed to maintain a steady proactive replacement of aging cables in the system and to complete certain work originally scheduled in 2019 and 2020. PG&E states that the work planned for 2019 and 2020 was rescheduled due to construction and estimating

[1297] PG&E Opening Brief at 513.

[1298] Cal Advocates Opening Brief at 227.

[1299] Cal Advocates Opening Brief at 227.

(design) resource constraints that it does not anticipate having in this rate case period.[1300]

Considering PG&E's deferral of work to higher priority matters in 2019 and 2020, the Commission finds PG&E's forecast for MAT 56A Underground Distribution Cable Replacement to be reasonable to maintain system reliability. Accordingly, the Commission adopts PG&E's request for capital expenditures of $38.013 million in 2021, $39.556 million in 2022, and $36.976 million in 2023 for MAT 56A Reliability Related Cable Replacement program. In addition, as with the overhead conductor replacement program and other reliability related electric distribution programs, PG&E shall provide in its 2027 GRC the following additional information to support forecasts for this cable replacement program: (1) data regarding outage levels for this equipment, (2) the age of the equipment being replaced, and (3) the unit cost for replacing it.

4.13.3.2. Critical Operating Equipment Cable Replacement (MAT 56C)

PG&E tracks work in MAT 56C Critical Operating Equipment Cable Replacement Program for replacing failed sections of underground distribution cable. This program tracks costs in MAT 56C to replace single segments of failed cable as opposed to the program costs tracked in MAT 56A that typically replaces much larger segments of cable over several city blocks.[1301] PG&E forecasts $36.002 million in 2023 capital expenditures[1302] to complete

[1300] PG&E Opening Brief at 459.

[1301] PG&E Opening Brief at 515.

[1302] PG&E Opening Brief at 515.

approximately 190 projects per year from 2021-2023, a $15 million increase from PG&E's 2020 capital expenditures.[1303]

Cal Advocates recommends that the Commission require PG&E to reduce its MAT 56C Critical Operating Equipment Cable Replacement Program pace of work to its 2019-2021 average pace of work, which would reduce PG&E's 2023 capital expenditures for this program to $24.6 million. Cal Advocates bases its recommendation on reducing PG&E's 2021 pace of work to 174 projects on the following: (1) extrapolating PG&E's 2021 pace of work; (2) the approximate average pace of work from 2019-2021 of 139 projects per year; and (3) PG&E has continued to propose high levels of work for wildfire-related programs, without explaining how it can maintain this increased pace or avoiding running into more construction and estimating resource constraints in 2022 and 2023.[1304]

In response, PG&E states that: (1) the lower pace of work executed in 2019-2020 was caused by construction and estimating (design) resource constraints; (2) PG&E has addressed its resource constraints, including estimating resources; and (3) PG&E is now more experienced at resourcing both wildfire mitigation and base work.[1305]

The parties' forecasts for this program differ primarily in PG&E's proposed pace of work or its ability to complete the work at the proposed pace in very general terms. To provide PG&E with the flexibility to complete the amount of work that is necessary and to protect ratepayers when the work is not performed, funds for reliability conductor replacement work shall be placed in a two-way balancing account and documented annually via a Tier 1 Advice Letter

[1303] Cal Advocates Opening Brief at 229.

[1304] Cal Advocates Opening Brief at 229-230.

[1305] PG&E Reply Brief at 460.

along with the following additional information to support future forecasts for this cable replacement program: (1) data regarding outage levels, (2) the useful lives of the equipment being replaced, and (3) the unit cost for replacing it. Accordingly, the Commission adopts PG&E's requested capital expenditure forecasts of $34.260 million in 2021, $33.030 million in 2022, and $36.002 million in 2023 for MAT 56C Critical Operating Equipment Cable Replacement Program.

4.13.3.3. Load Break Oil Rotary Switch Replacements (MAT 56S)

PG&E tracks costs related to underground load break oil rotary (LBOR) switches in MAT 56S LBOR Switch Replacement program. PG&E states that these switches are manually operated, oil-filled switches that use solid blade mechanisms immersed in oil to break or make loads but that LBOR switches manufactured before 1975 pose a safety risk for crews, as they may fail. PG&E states that it is working to replace these and other antiquated switches with devices that conform to current design standards.[1306] PG&E requests capital expenditures of $9.252 million in 2021, $9.493 million in 2022, and $8.124 million in 2023 capital expenditures for the MAT 56S LBOR Switch Replacement program.[1307] PG&E's 2023 request represents a $2.7 million increase over PG&E's 2020 capital expenditures.[1308] PG&E states that it bases its LBOR switch replacement forecast on a rate of replacement of 77 switches per year during this rate case period.[1309] PG&E states this rate of replacement is consistent with the

[1306] PG&E Ex-04 at 13-39 to 13-40; PG&E Opening Brief at 516.

[1307] PG&E Opening Brief at 516.

[1308] Cal Advocates Opening Brief at 230-231.

[1309] PG&E Ex-04 at 13-40.

LBOR rate of replacement adopted in the 2020 GRC settlement.[1310] PG&E also states that its rate of replacement is consistent with the prior the recommendation of the Commission's Safety and Enforcement Division (previously known as the Office of Safety Advocates). The Office of Safety Advocate stated that the LBOR switches are a known safety hazard and pose a threat to public safety and PG&E employees, especially when operated long past their service life and recommended that PG&E accelerate the replacement of pre-1975 LBOR switches.[1311]

Cal Advocates recommends reducing PG&E's 2023 capital expenditures for this program by $5.7 million to $2.4 million because, according to Cal Advocates, two-thirds of pre-1975 LBOR switches do require replacement and a five-year average of unit costs rather than a three-year average results in a lower amount and smooths out the effects of the variable unit costs.[1312]

The Commission finds that pre-1975 LOBR switches present an unreasonable risk to workers and to reliability, and, as a result, finds that PG&E should not decrease the forecasted rate of replacement, as suggested by Cal Advocates. The Commission finds PG&E's forecast is reasonable for MAT 56S LBOR Switch Replacement program. Accordingly, the Commission adopts PG&E's capital expenditure request of $9.252 million for 2021, $9.493 million for 2022, and $8.1 million for MAT 56S LBOR Switch Replacement. In addition, the Commission directs PG&E to include additional information regarding the LBOR Switch Replacement program, including the number of

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[1310] PG&E Ex-04 at 13-40.

[1311] PG&E Opening Brief at 518.

[1312] Cal Advocates Opening Brief at 231.

LOBR switches in operation, the service life, and years in service in PG&E's next GRC.

4.13.3.4. Temperature Alarm Devices (MAT 56T)

PG&E tracks costs in MAT 56T Temperature Alarm Devices (TAD) Program that involve installation of temperature monitors on targeted oil-filled subsurface equipment, such as LBOR switches, that send an alarm signal when abnormal temperatures are detected.[1313] PG&E explains that Temperature Alarm Devices are battery-powered remote sensing units that continuously capture and analyze temperature data from the oil-filled equipment to prevent catastrophic equipment failures.[1314] PG&E requests capital expenditures of $9.589 million in 2021, $3.303 million in 2022, and $9.1 million in 2023 capital for the Temperature Alarm Devices program, which represents a $0.9 million increase from PG&E's 2020 capital expenditures.[1315] PG&E states the increase reflects a plan to continue ramping up this relatively new program, which PG&E bases on 2018-2020 average unit costs, equivalent to a unit cost of $3,966 in 2023 dollars.[1316]

Cal Advocates does not dispute the need for the TAD program or the number of units to be replaced in this program. Cal Advocates only disputes PG&E's estimated program costs. Cal Advocates recommends that PG&E reduce the TAD program forecast from $9.1 million to $8.5 million using 2019-2020 for the unit cost instead of a unit cost based on the 2018-2020 average. Cal Advocates contends that data on PG&E's 2018 unit cost should be excluded because PG&E's

[1313] Cal Advocates Opening Brief at 232.

[1314] PG&E Opening Brief at 518.

[1315] PG&E Opening Brief at 519.

[1316] Cal Advocates Opening Brief at 232.

2018 unit cost of $138,100 was over 40 times PG&E's unit costs in 2019 and 2020.[1317]

PG&E maintains that its 2018 unit cost should be included in the average used for forecasting because it is still incurring start-up-related costs similar to those incurred in 2018. To support that, PG&E states that it is developing a long-term connectivity strategy (and incurring associated startup costs), which includes implementing a new cyber-safe approach outside of PG&E's Distribution Control Center.[1318]

The Commission finds that PG&E's explanation fails to support continued use of the 2018 unit cost after the unit cost dropped approximately 40 times in 2019 and 2020. Accordingly, the Commission finds the forecast presented by Cal Advocates reasonable and adopts Cal Advocates 2022 capital forecast for the MAT 56T Temperature Alarm Devices of $8.928 million in 2021, $3.075 million in 2022, and $8.5 million in 2023.

4.14. Network Asset Management

PG&E's Electric Distribution Network includes assets to ensure that its distribution networks are designed to be redundant for the commercial and residential customers in specific areas of its service territory, namely the downtown areas of San Francisco and Oakland.[1319] These distribution network electric assets are located underneath sidewalks and streets or in high-rise buildings.[1320]

1317 Cal Advocates Opening Brief at 232- 233.

1318 PG&E Opening Brief at 463.

1319 PG&E Ex-04 at 14-1.

1320 PG&E Ex-04 at 14-1.

PG&E forecasts 2023 expense of $5.021 million for operations and maintenance of Electric Distribution Network.[1321] PG&E states that the 2023 forecast is $0.1 million higher than PG&E's 2020 recorded costs of $4.9 million, which is a 2.7% expense increase.[1322] PG&E tracks this expense in MWC KC Network Preventive Maintenance and Repair.[1323] PG&E's expense forecast for Electric Distribution Network MWC KC Network Preventive Maintenance and Repair is uncontested. The Commission finds this uncontested expense forecast of $5.021 million for MWC KC Network Preventive Maintenance and Repair Electric Distribution Network reasonable.

PG&E requests capital expenditures of $41.1 million for 2021, $44.0 million for 2022, $44.4 million for 2023, $45.3 million for 2024, $46.3 million for 2025, and $47.3 million for 2026 for capital additions and replacement of deteriorated or obsolete Electric Distribution Network equipment.[1324] PG&E's 2020 recorded capital expense is $44.495 million.[1325] PG&E tracks these capital expenditures in two Major Work Categories: (1) MWC 2C Install/Replace Network Assets, and (2) MWC 56 Electric Distribution UG Asset Replacements.[1326] AARP and Cal Advocates contest certain aspects of PG&E's capital expenditures request. The Commission considers PG&E's capital request and the objections by AARP and Cal Advocates, below.

[1321] PG&E Ex-04 at 14-2; PG&E-17 (Rebuttal) at 14-3. (Forecast does not reflect September 6, 2022 Update Testimony (PG&E Ex-33) escalation rates.)

[1322] PG&E Ex-04 at 14-2.

[1323] PG&E Ex-04 at 14-3.

[1324] PG&E Ex-04 at 14-2.

[1325] PG&E Ex-04 at 14-4.

[1326] PG&E Ex-04 at 14-3.

PG&E states that its work tracked in MWC 2C Install/Replace Network Assets includes ongoing replacement of network transformers and network protectors, installation of new Supervisory Control and Data Acquisition (SCADA) safety monitoring equipment, and installation of new venting manhole covers on vaults.[1327] Work recorded in MWC 56 includes reliability-related replacement of primary and secondary network cables.[1328] PG&E tracks cost within MWC 2C in several Maintenance Activity Type (MAT) subcategories, including MAT 2CA and MAT 2CC Network Transformer, Protector and Relay Replacement, MAT 2CB Fiber/SCADA Communications Replacement, MAT 2CD Venting Manhole Cover, MAT 2CE Network SCADA Safety Monitoring, MAT 2C# Other, and MAT 2CP Other.[1329]

AARP recommends disallowing a combined $72.5 million (approximately 33%) of PG&E's capital request for MWC 2C Install/Replace Network Assets.[1330] Regarding work recorded in MAT 2CC Network Transformer, Protector and Relay Replacement, AARP contends that changing out older dry-type transformers in high-rise buildings is unnecessary because these transformers almost never fail and, even when these transformers fail, dry-type transformers are specifically designed not to catch fire.[1331]

AARP also recommends no funding for Network Component Replacements. In response, PG&E states that replacing dry-type transformers

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[1327] PG&E Ex-04 at 14-13 to 14-14.

[1328] PG&E Opening Brief at 521.

[1329] PG&E Ex-04 at 14-19.

[1330] AARP Ex-01 at 44-46; PG&E Opening Brief at 522.

[1331] AARP Opening Brief at 34.

under MAT 2CC ensures network reliability, not just fire safety.[1332] PG&E asserts that it is important to replace older dry-type transformers because, since these transformers are custom-made, PG&E is unable to retain stock of spare units and a replacement unit takes six to eight months.[1333]

Regarding the Network Component Replacements, PG&E states it is continuing its program to upgrade 1980s vintage monitoring equipment.[1334] AARP proposes zero funding because, according to AARP, replacement is not needed until equipment fails.[1335] PG&E disagrees and states that the new upgraded SCADA systems are needed because they are, among other things, designed to improve safety on the distribution networks.[1336]

AARP also recommends that the Commission reduce PG&E's forecast for the Primary Network Cable Replacement Program but provides no rationale to support its recommendation.[1337] PG&E states that without funding this aspect of its program, aging primary network cables are at risk of failing and pose a safety risk to people and property in close proximity to the network system.[1338]

Regarding the capital work recorded in MWC 56 Electric Distribution UG Asset Replacements, PG&E indicates that its Network Systems Replacement Program started in 2012 to replace primary and secondary cables and modifying

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[1332] PG&E Opening Brief at 527.

[1333] PG&E Opening Brief at 528.

[1334] PG&E Opening Brief at 529.

[1335] AARP Ex-01 at 44-46.

[1336] PG&E Opening Brief at 530.

[1337] AARP Ex-01 at 46-47.

[1338] PG&E Opening Brief at 532-533.

network transformers to accept the new primary cables.[1339] PG&E states that many of the existing network primary and secondary cables date back to between the 1920s and the 1960s and are reaching the end of their service life.[1340] AARP states that no justification exists for "pre-emptive replacement" of network assets of any kind because underground networks are "extremely" redundant, and if a network cable fails, it is replaced with no service interruption to customers.[1341] PG&E indicates that proactively identifying and replacing equipment is crucial to maintaining system reliability.[1342] Furthermore, PG&E states that primary and secondary network cable failures pose a safety risk from manhole displacements, vault explosions, smoke and fires, some of which may cause personal injury and property damage.[1343]

Cal Advocates recommends the Commission adopt a lower forecast based on calculation from PG&E's updated 2021 capital expenditures provided by PG&E to Cal Advocates in 2022. The Commission rejects this proposal and will rely on PG&E's 2021 figures, consistent with PG&E's June 30, 2021 Application.

The Commission is not persuaded by AARPs recommendations regarding the forecast for work tracked in (1) MWC 2C Install/Replace Network Assets, and (2) MWC 56 Electric Distribution UG Asset Replacements. PG&E is proposing a reasonable work plan to replace aging equipment to maintain safety and reliability. In addition, proactive replacement in this instance helps PG&E to use its resources efficiently and avoid the need to scramble to do repairs on an

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[1339] PG&E Ex-04 at 14-20.

[1340] PG&E Ex-04 at 14-20.

[1341] AARP Ex-01 at 45.

[1342] PG&E Ex-17 (Rebuttal) at 14-17.

[1343] PG&E Ex-17 (Rebuttal) at 14-17.

emergency basis. Doing repairs on an emergency basis for these assets might put PG&E in a position where it may not be able to do repairs because needed equipment is already deployed elsewhere. The Commission also declines to rely on the recorded 2021 costs, which PG&E submitted in this proceeding on March 9, 2022, after filing its Application on June 30, 2021.

Accordingly, regarding (1) MWC 2C Install/Replace Network Assets, and (2) MWC 56 Electric Distribution UG Asset Replacements, the Commission adopts capital expenditures of $41.1 million for 2021, $44.0 million for 2022, and $44.4 million for 2023 for capital additions and replacement of deteriorated or obsolete Electric Distribution Network equipment.[1344] The uncontested expense forecast of $5.021 million for MWC KC Network Preventive Maintenance and Repair is found reasonable.

4.15. Substation Asset Management

PG&E states that it operates 758 electric distribution substations—which are the hubs of its electric distribution system—consisting of power transformers, circuit breakers, switchgears, protective relays, bus structures, and voltage regulation equipment.[1345] Each substation transforms high voltage electricity from PG&E's electric transmission system to lower voltage for delivery to PG&E's customers.[1346] PG&E operates its substations within its Substation Asset Management Program.[1347]

[1344] PG&E Ex-04 at 14-2.

[1345] PG&E Ex-04 at 15-1.

[1346] PG&E Ex-04 at 15-1.

[1347] PG&E Ex-04 at 15-1.

PG&E requests a 2023 expense forecast of $50.9 million for its Substation Asset Management Program to maintain and operate substations.[1348] This forecast represents a 0.6% decrease from PG&E's 2020 recorded expense of approximately $51.2 million.[1349] PG&E tracks its expense for Substation Asset Management in MWC GC Operate and Maintain Substations.[1350] PG&E states that its key cost drivers include expense for major emergency corrective maintenance of substations as well as substation vegetation management, which is a wildfire risk mitigation cost.[1351] These expense costs account for more than half of the requested expense.[1352] PG&E's expense forecast is undisputed and, as such, the Commission finds PG&E's 2023 expense forecast of $50.9 million for its Substation Asset Management Program, which is tracked in MWC GC Operate and Maintain Substations, reasonable.

PG&E requests capital expenditures of $225.3 million for 2021, $204.2 million for 2022, and $208.1 million for 2023.[1353] The 2023 capital forecast represents a 10% decrease over PG&E's 2020 recorded capital costs of $231.8 million.[1354] PG&E's capital expenditures are tracked in four Major Work Categories: (1) MWC 48 Replace Substation Equipment, (2) MWC 54 Distribution Transformer Replacements, (3) MWC 58 Distribution Substation Safety and

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[1348] PG&E Ex-04 at 15-1.

[1349] PG&E Ex-04 at 15-1.

[1350] PG&E Ex-04 at 15-2.

[1351] PG&E Ex-04 at 15-2, 15-21, and 15-22.

[1352] PG&E Ex-04 at 15-22 (Table 15-8).

[1353] PG&E Ex-04 at 15-4.

[1354] PG&E Ex-04 at 15-2.

Security, and (4) MWC 59 Distribution Substation Emergency Equipment Replacement.[1355]

PG&E's key capital cost drivers are the MWC 48 Replace Substation Equipment and MWC 59 Distribution Substation Emergency Equipment Replacement Programs, which together comprise a large percentage of the total requested expenditures.[1356] Some of PG&E's work within Substation Asset Management is wildfire mitigation work, such as vegetation management around substations.[1357] PG&E indicates that its past wildfire mitigation work was recorded in the WMPMA, which PG&E removed from this proceeding to seek reasonableness review and authorization to collect from ratepayers in a separate application before the Commission.[1358] In 2020, PG&E recorded approximately $12.5 million in capital and $3.1 million in expense in the WMPMA related to Substation Asset Management.[1359] In 2023, PG&E forecasts capital expenditures of $6.5 million for wildfire risk mitigations.[1360]

AARP, Cal Advocates, and TURN propose alternative forecasts for certain categories of capital expenditures, as illustrated in the below chart.

Table 4-K:
Electric Substation Asset Management Capital Expenditures ($1,000)

Program	Program MWC	2020 PG&E Recorded	2021 Recorded	Party	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
	MWC 48	$77.377		PG&E	$76.601	$9.588	$96.331	$87.218	$84.078	$77.723
				AARP						

[1355] PG&E Ex-04 at 15-2; PG&E Opening Brief at 553-554.

[1356] PG&E Ex-04 at 15-4 (Figure 15-2).

[1357] PG&E Ex-04 at 15-21.

[1358] PG&E Ex-04 at 15-5, 15-21, and 15-44.

[1359] PG&E Ex-04 at 15-44.

[1360] PG&E Ex-04 at 15-18.

Program	Program MWC	2020 PG&E Recorded	2021 Recorded	Party	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
Replace Substation Equipment[1361]				CALPA	$62.756	$75.532	$68.757	-	-	-
				TURN	-	$55,033	$77,715	-	-	-
Distribution Transformer Replacement[1362]	MWC 54	$3.,907		PG&E	$40.766	$27.970	$21.243	$30.294	$35.418	$38.721
				AARP	-	-	$5,229	$6.303	$6.946	$7.392
				CALPA	$39.719	$27.640	$21.003	-	-	-
Distribution Substation Safety and Security[1363]	MWC 58	$3.369		PG&E	$5.980	$1.738	$8.232	$12.882	$15.743	$22.218
				CALPA	$4.332	$3.487	$5.173	-	-	-
Distribution Substation Emergency Equipment Replacement[1364]	MWC 59	$119.133		PG&E	$101.935	$77.872	$82.323	$84.550	$86.831	$89.175

The disputed capital expenditures requests are addressed below.

We first address the forecast for work tracked in MWC 48 Replace Substation Equipment. PG&E includes 11 MAT codes within MWC 48.[1365] PG&E's MATs 48A, 48B, and 48R are uncontested and represent approximately $4.220 million of PG&E's forecast presented for work tracked in MWC 48 Replace Substation Equipment.[1366] Cal Advocates recommends reductions to MATs 48D,

[1361] PG&E-04 at 15-30 (Table 15-9).

[1362] PG&E-04 at 15-35 (Table 15-10). Totals reflect forecast adjustments made to ensure that total forecasts did not exceed Plan of Reorganization forecasts. Forecast adjustment was $113,000 in 2021. For more information, PG&E Ex-04, Ch. 2, Section D.

[1363] PG&E Ex-04 at 15-39 (Table 15-11). The 2020 recorded and 2021 forecast totals include costs attributed to the now discontinued MAT 58C subprogram (Distribution Substation Miscellaneous Equipment) to enable forecasting for the Applied Technical Services-funded work and has since been removed. The costs were $16,000 and $21,000 in 2020 and 2021, respectively.

[1364] PG&E-04 at WP 15-35 (Table 15-34). The totals here reflect forecast adjustments made to ensure that total forecasts did not exceed Plan of Reorganization forecasts. Forecast adjustment was $1.709 million in 2021. PG&E Ex-04, Ch. 2, Section D for more information.

[1365] PG&E Opening Brief at 534.

[1366] PG&E Opening Brief at 534.

48X, 48C, 48H, 48N, and 48F. [1367] TURN recommends a reduction to the forecast presented for MAT 48D.[1368] AARP recommends reductions to MATs 48D, 48E, and 48L.[1369]

4.15.1. Circuit Breaker Replacement (Capital MAT 48D)

PG&E tracks capital expenditures for its Circuit Breaker Replacement program in MAT 48D, which includes work to prioritize and replace deteriorating and obsolete distribution circuit breakers before in-service failure.[1370] PG&E's 2023 capital expenditure forecast for MAT 48D Circuit Breaker Replacement is $28.6 million, a $24.1 million increase from PG&E's recorded 2020 capital expenditures of $4.5 million.[1371] PG&E's capital expenditures request for 2021 is $14.3 million and for 2022 is $31.3 million.[1372] PG&E states that it plans to replace 16 circuit breakers in 2021, 37 in 2022, and 40 in 2023.[1373] However, as Cal Advocates states, PG&E only replaced between 0-6 circuit breakers per year in 2016-2020.[1374]

AARP disputes the cost forecast for the Circuit Breaker Replacement Program under MAT 48D, recommending a forecast reduction totaling $121.976 million over four-years, 2023-2026.[1375] AARP alleges that PG&E's

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[1367] PG&E Opening Brief at 534-535.

[1368] PG&E Opening Brief at 534-535.

[1369] PG&E Opening Brief at 534-535.

[1370] PG&E Opening Brief at 535.

[1371] PG&E Ex-04 at 15-24.

[1372] PG&E Ex-04 at 15-24.

[1373] PG&E Ex-04 at 15-24.

[1374] Cal Advocates Opening Brief at 236.

[1375] AARP Ex-01 at 50.

practice of pre-emptive equipment replacement utilizes subjective assessments of an asset's age and condition as opposed to using more objective methods that all utilities employ.[1376] AARP alleges that PG&E's pre-emptive replacement strategy for these assets is profit driven as fully depreciated equipment that remains in service earns no rate of return.[1377]

PG&E disagrees with AARP and contends that it does not rely on non-objective criteria and that equipment testing is not the only criterion that would trigger a replacement.[1378] PG&E further states that there are many benefits to using a proactive approach rather than relying solely on just-in-time replacement.[1379] Finally, PG&E states that because it has a large population of assets at or near end of life, it would not be feasible to address a cluster of failures likely to occur when a large number of assets reach end of life at the same time, which would also burden other programs which are forecasted lower precisely because of the proactive replacement strategy.[1380]

Cal Advocates recommends $15.9 million for 2023 capital expenditures for this program, which is $12.7 million lower than PG&E's proposal. Cal Advocates' recommendation is based on reducing PG&E's MAT 48D pace of work to its 2016-2020 maximum pace of work.[1381]

TURN recommends that the Commission reduce PG&E's forecast for MAT 48D Circuit Breaker Replacement to $9.7 million in 2022 and $10 million in

[1376] AARP Ex-01 at 48.

[1377] AARP Ex-01 at 49.

[1378] PG&E Ex-17 (Rebuttal) at 15-14.

[1379] PG&E Ex-17 (Rebuttal) at 15-15.

[1380] PG&E Ex-17 (Rebuttal) at 15-15.

[1381] Cal Advocates Opening Brief at 238.

2023 to better reflect historical levels of PG&E spending.[1382] In the alternative, TURN recommends that the Commission adopt a one-way balancing account to protect ratepayers from overpaying if the utility continues its habit of significantly underspending in this program.[1383]

The Commission finds reasonable PG&E's capital request for its Circuit Breaker Replacement Program (MAT 48D) of $14.3 million for 2021, $31.3 million for 2022, and $28.6 million in 2023 because the forecast seeks to align safety, reliability, and other benefits with a more proactive and reasonable circuit breaker replacement rate.

4.15.2. Switch Replacement Subprogram (Capital MAT 48E)

PG&E tracks capital costs in MAT 48E Switch Replacement Subprogram related to replacing motor operated air switches, circuit switches, or disconnect switches that are damaged or obsolete, are difficult and/or unsafe for personnel to operate or require a high frequency of maintenance and repair.[1384] PG&E requests capital expenditures of $945,000 in 2021 and $3.457 million in 2022.[1385] PG&E's 2023 capital expenditure forecast is $2.166 million.[1386]

AARP disputes the cost forecast for MAT 48E Switch Replacement Subprogram and recommends removing certain costs, totaling $14.706 million over the rate case period, 2023-2026.[1387] AARP alleges that PG&E's practice of pre-emptive equipment replacement utilizes subjective assessments of an asset's

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[1382] TURN Opening Brief at 465-468.

[1383] TURN Opening Brief at 465-468.

[1384] PG&E Ex-04 at 15-27.

[1385] PG&E Ex-04 at WP 15-35.

[1386] PG&E Ex-04 at WP 15-35.

[1387] AARP Ex-01 at 50.

age and condition as opposed to using more objective methods that all utilities employ.[1388] AARP alleges that PG&E's pre-emptive replacement strategy for these assets is profit driven as full depreciated equipment that remains in service earns no rate of return.[1389]

PG&E disagrees with AARP's recommendation for the same reasons as explained above regarding MAT 48D Circuit Breaker Replacement, stating that these assumptions are incorrect and proactive replacement has significant advantages over emergency replacement.[1390] PG&E states that defunding proactive substation equipment replacement would not only deprive PG&E customers of the advantages of proactive replacement discussed above, it would also lead to additional in-service failures that would need to be replaced on a just in time/emergency basis as part of PG&E's Emergency Substation Equipment Replacement program in MWC 59.[1391]

Cal Advocates disputes the cost forecast for Switch Replacement Subprogram under MAT 48E, recommending $1.9 million for 2023 capital expenditures for this subprogram, which is $0.2 million lower than PG&E's proposal.[1392] Cal Advocates states that the 2020 expenditures were anomalously high at $2.7 million, considering expenditures from 2016-2020 never exceeded $1.8 million.[1393] Cal Advocates further states that, in this instance, annual unit

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[1388] AARP Ex-01 at 48.

[1389] AARP Ex-01 at 49.

[1390] PG&E Ex-17 (Rebuttal) at 15-23.

[1391] PG&E Ex-17 (Rebuttal) at 15-23.

[1392] CALPA Ex-06 at 76.

[1393] CALPA Ex-06 at 76.

costs are not necessarily representative of annual expenditures.[1394] Cal Advocates recommends the 2021 forecast be based on the extrapolated pace of work for units completed, while 2022-2023 forecasts should reflect the average annual spend from 2019-2021.[1395] CUE opposes Cal Advocates' assertion that the pace of work is flawed and states that PG&E's request is reasonable.[1396] PG&E explains that its requests are reasonable and that the level of work proposed is achievable.[1397] PG&E states its goal is to be more proactive with switch replacements by identifying legacy switches and those with missing attachments that may not be bundled or captured through breaker replacement projects.[1398] PG&E states that the forecast level and ramp up adequately reflect the time required to identify locations and replace the switches.[1399]

The Commission finds PG&E's capital expenditures requests for MAT 48E Switch Replacement Subprogram of $945,000 in 2021, $3.457 million in 2022, and $2.166 million in 2023, which seeks to align safety, reliability and other benefits with a more proactive switch replacement rate, reasonable.

4.15.3. Animal Abatement (Capital MAT 48X)

PG&E tracks capital expenditures regarding animal abatement measures concerning substations in MAT 48X Animal Abatement.[1400] PG&E states that animal contacts are one of the main contributors to substation outage events with

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[1394] CALPA Ex-06 at 76.

[1395] CALPA Ex-06 at 77.

[1396] CUE Ex-02 at 11-13

[1397] PG&E Ex-17 (Rebuttal) at 15-22.

[1398] PG&E Ex-17 (Rebuttal) at 15-22.

[1399] PG&E Ex-17 (Rebuttal) at 15-22.

[1400] PG&E Ex-04 at 15-25.

the highest impact and animal abatement is also a key program in PG&E's Wildfire Mitigation Plan.[1401] PG&E's 2023 capital forecast for MAT 48X is $5.760 million, which represents a $0.8 million increase from PG&E's 2020 capital expenditures of $4.961 million.[1402] PG&E states that its 2023 forecast represents a steady state replacement rate of 17 sites per year for animal abatement mitigations.[1403] PG&E requests capital expenditures of $4.533 million in 2021 and $5.404 million in 2022.[1404]

Cal Advocates recommends $2.3 million for 2023 capital expenditures (MAT 48X), which is $3.5 million lower than PG&E's proposal.[1405] Cal Advocates questions PG&E's ability to achieve the pace of work it proposes based on its past performance.[1406] Cal Advocates' recommendation is based on reducing PG&E's 2021 pace of work to eight installations, the extrapolated pace of work PG&E appears on track to accomplish from PG&E's 2021 cost data, and reducing PG&E's 2022-2023 work to five installations per year, the approximate average pace of work from 2019-2021.[1407]

The Commission finds PG&E's capital expenditures request for MAT 48X Animal Abatement of $4.533 million in 2021, $5.404 million in 2022, and $5.760 million for 2023, which aligns safety, reliability and other benefits with a more proactive approach, reasonable.

1401 PG&E Ex-17 (Rebuttal) at 15-16.

1402 PG&E Ex-17 (Rebuttal) at 15-32 (Table 15-6).

1403 Cal Advocates Opening Brief at 238.

1404 PG&E Ex-17 (Rebuttal) at 15-6 (Table 15-32).

1405 CALPA Ex-06 at 69.

1406 Cal Advocates Opening Brief at 257.

1407 CALPA Ex-06 at 69; Cal Advocates Opening Brief at 239.

4.15.4. Battery Replacement (Capital MAT 48C)

PG&E tracks work in MAT 48C Battery Replacement that consists of proactive replacement of substation batteries that are used to power equipment such as protective relays, control systems, and communications equipment. PG&E requests capital expenditures MAT 48C Battery Replacement of $200,000 in 2021and $3 million in 2022.[1408] PG&E's 2023 capital expenditure forecast for MAT 48C is $3.3 million, which represents a $3.0 million increase from PG&E's recorded 2020 capital expenditures.[1409] PG&E states that its forecast will permit it to proactively install batteries at a sustainable level of 10 per year starting in 2022.[1410]

Cal Advocates proposes a lower forecast for 2022 and 2023 and contends that PG&E's expected pace of work should be reduced to levels consistent with its past work and, in addition, that PG&E's work in this area can be done on a "just-in-time" basis, rather than on a proactive basis.[1411] In response, PG&E and CUE contend that proactive replacement work is important to avoid in-service failures and that a strategy of "just-in-time" replacement is not reasonable because PG&E does not keep an emergency stock of batteries due to the need to custom design.[1412]

The Commission finds PG&E's 2023 capital expenditure forecast for MAT 48C Battery Replacement of $200,0000 in 2021, $3 million in 2022, and $3.3 million in 2024 reasonable because, in this instance, proactive replacement of

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[1408] PG&E Ex-04 at 15-25.

[1409] PG&E Ex-04 at 15-25.

[1410] PG&E Ex-04 at 15-25 to 15-26.

[1411] Cal Advocates Opening Brief at 240-241.

[1412] PG&E Ex-17 (Rebuttal) at 15-17.

these components avoids negative reliability consequences of failures and allows flexibility to accommodate supply chain and other delivery issues with these components.

4.15.5. Line Work Support (Capital MAT 48L)

PG&E tracks work related to major and minor substation equipment replacements in MAT 48L Line Work Support and other MAT codes.[1413] More specifically, MAT 48L Line Work Support tracks PG&E's work associated with distribution lines related to substation equipment replacement activities, such as switchgear and transformer replacement projects.[1414]

PG&E requests capital expenditures of $24.931 million in 2021, $6.027 million in 2022, and $9.105 million in 2023.[1415] PG&E's recorded 2020 capital expenditure for MAT 48L Line Work Support is $15.926 million.[1416]

Cal Advocates does not dispute the total forecast cost for MAT 48L Line Work Support but recommends that the "unspent" $5.6 million from 2021 be moved to the 2022 forecast. PG&E states that it is not appropriate to shift forecast funds that were not used in 2021 to 2022 because 2022 is a separate forecast year.[1417] AARP contends that PG&E's proactive replacement program is not based on objective criteria and, as a result, proposes cost disallowances for this program.[1418]

[1413] PG&E Ex-04 at 15-23 to 15-26.

[1414] PG&E Ex-04 at 15-23 to 15-26.

[1415] PG&E Ex-04 at 15-30 (Table 15-9).

[1416] PG&E Ex-17 (Rebuttal) at 15-6 (Table 15-32).

[1417] CALPA Ex-06 at 72-73.

[1418] AARP Ex-01 at 48-50.

The Commission finds reasonable PG&E's capital expenditures forecast for MAT 48L Line Work Support of $24.931 million in 2021, $6.027 million in 2022, and $9.105 million in 2023 because PG&E's robust proactive replacement program for these types of assets appears critical to maintaining reliability and public safety. The Commission is not convinced that Cal Advocates' reductions are appropriate at this point in the proceeding. Moreover, the Commission is not persuaded by AARP's position that proactive replacement of assets should be completely disallowed because PG&E criteria for evaluating the need for replacement is not reliable.

4.15.6. Other Equipment Replacement Work

PG&E tracks additional work in Other Equipment Replacement Work in the following MAT Codes: MAT 48A Ancillary Equipment Replacement, MAT 48F Switchgear Replacement, MAT 48H Civil Structure, and MAT 48N Insulator Replacement.[1419] PG&E also tracks costs in MAT 48B Regulator Replacement and MAT 48R Arc Flash Reduction that are part of Other Equipment Replacement Work, but the forecasts for these MATs are not contested and are de minimis.[1420] PG&E's request for capital expenditures for the work tracked in Other Equipment Replacement Work is $5.858 million for 2021, $19.608 million for 2022, and $17.218 million for 2023. PG&E's recorded adjusted capital expenditure in 2020 for Other Equipment Replacement Work is $6.335 million.

MAT 48A Ancillary Equipment Replacement includes work for replacement of transformer cooling fans and radiators, substation service

[1419] PG&E Ex-17 (Rebuttal) at 15-6 (Table 15-32).

[1420] PG&E Ex-17 (Rebuttal) at 15-6 (Table 15-32).

transformers, and ground grid upgrades or replacements.[1421] PG&E's 2023 capital expenditure forecast is $4.220 million.[1422] This request is not contested.

MAT 48F Switchgear Replacement includes equipment such as electrical disconnect switches, bus conductors, and circuit breakers used to interrupt power flow, isolate problems, and protect electrical equipment.[1423] PG&E's capital expenditure forecast for MAT 48F Switchgear Replacement is $26.8 million in 2021, $31.3 million in 2022, $32.4 million in 2023, $16.7 million in 2024, $16.6 million in 2025, and $15.7 million in 2026.[1424] Cal Advocates does not oppose PG&E's 2021-2023 capital expenditure forecasts but states that, in the 2018-2020 GRC cycle, PG&E's El Cerrito G Substation Rebuild project had $1.5 million in costs for delays and design extension due to the involvement of multiple engineering teams in the design process that led to design gaps.[1425] Cal Advocates states that, since PG&E's engineering design process caused unreasonable delays, Cal Advocates recommends denying recovery of $1.5 million from PG&E's 2020 recorded costs.[1426] PG&E opposes Cal Advocates' recommendation.[1427] PG&E suggests that the "involvement of multiple engineering teams in the design process is not a flaw in the design process, but rather a natural result of the complexity of the El Cerrito G project and of

[1421] PG&E Ex-04 at 15-26.

[1422] PG&E Ex-04 at WP 15-35.

[1423] PG&E Ex-04 at 15-23.

[1424] PG&E Ex-04 at 15-24.

[1425] Cal Advocates Opening Brief at 255.

[1426] Cal Advocates Opening Brief at 255.

[1427] PG&E Reply Brief at 473.

scope/schedule/cost refinement in the course of project execution."[1428] While PG&E's explanation is persuasive, the Commission expects PG&E to work within expected budget on all of its projects, many of which are complex.
Cal Advocates' request is not adopted.

MAT 48H Civil Structures Replacement includes work to replace structures such as roofs as well as current-carrying equipment, and this work includes the mitigation aimed at minimizing wood structures in substations.[1429] PG&E requests capital expenditures in 2021 of $514,000 and in 2022 of $4.1 million.[1430] PG&E's 2023 capital expenditure forecast for MAT 48H is $5.416 million for the support of eight in-flight civil projects.[1431] Cal Advocates disputes the 2021, 2022, and 2023 capital forecast for MAT 48H Civil Infrastructure and for 2023 recommends a forecast of $0.5 million in capital expenditures for this subprogram, a recommendation which is $4.9 million lower than PG&E's request.[1432] Cal Advocates' reduction in cost is based on increasing PG&E's 2021 pace of work to $1.4 million, the extrapolated pace of work PG&E appears on track to perform from PG&E's 2021 cost data, and then reducing PG&E's 2022-2023 costs to $0.5 million per year, the approximate average pace of work from 2019-2021.[1433] CUE opposes Cal Advocates' assertion that PG&E's proposed pace of work is inaccurate and contends PG&E's request is

[1428] PG&E Ex-17 (Rebuttal) at 15-24.

[1429] PG&E Ex-04 at 15-27 to 15-28.

[1430] PG&E Ex-17 (Rebuttal) at 15-33 (Table 15-7) and PG&E Ex-17 (Rebuttal) at 15-4 (Table 15-2).

[1431] PG&E Ex-17 (Rebuttal) at 15-4.

[1432] CALPA Ex-06 at 73.

[1433] CALPA Ex-06 at 74.

reasonable.[1434] PG&E states that its forecast is reasonable and the levels of work contained therein achievable.[1435]

The Commission finds PG&E's request for capital expenditures in 2021 of $514,000, $4.113 million in 2022, and $5.416 million in 2023 reasonable for MAT 48H Civil Structures Replacement because, in this instance, PG&E's proactive replacement has several advantages over PG&E's prior strategy of "just-in-time" replacement and part of a comprehensive replacement strategy along with emergency replacement.

PG&E tracks in MAT 48N Insulator Replacement work to replace certain insulators within PG&E's substations that are prone to failure.[1436] PG&E forecasts capital expenditures of $5.416 million in 2023 for MAT 48N Insulator Replacement, which represents a $4.8 million increase over PG&E's 2020 capital expenditures of $0.6 million.[1437] PG&E states that its forecasted 2023 spending is higher than 2020 spending because its 2020 expenditures represent work on a certain type of insulator, whereas the 2023 spending represents expanding the subprogram to other types of insulators.[1438] PG&E requests $0 in 2021 and $0.5 million in 2022 in capital expenditures for the Insulator Replacement program.[1439]

[1434] CUE Ex-02 at 11 to 13.

[1435] PG&E Ex-17 (Rebuttal) at 15-20.

[1436] PG&E Ex-04 at 15-28; PG&E Opening Brief at 542.

[1437] PG&E Ex-04 at 15-28; PG&E Ex-17 (Rebuttal) at 15-4 (Table 15-2).

[1438] PG&E Opening Brief at 542.

[1439] PG&E Ex-04 at 15-28. PG&E Ex-04 at 15-28 to 15-29, stating PG&E's 2020 recorded expenditures were for transmission voltage distribution class Ohio Brass insulator replacements that have known catastrophic failure modes. The 2023 forecast represents an expansion of the program to address additional Ohio Brass insulators as well as other types of older distribution class and distribution voltage insulators because the risk is still present.

Cal Advocates recommends that the Commission require PG&E to reduce its MAT 48N pace of work to its 2019-2021 average pace of work, which would reduce PG&E's 2023 capital expenditures for the Insulator Replacement subprogram from $5.4 million to $2.0 million.[1440] In support of its recommendation, Cal Advocates states that PG&E has not shown that an expanded pace of work is feasible.[1441]

PG&E states its insulator replacement work at the level planned is achievable.[1442] PG&E further states that proactive replacement has several advantages over just-in-time replacement and should be part of a comprehensive replacement strategy along with emergency replacement.[1443]

The Commission finds, in this instance, that PG&E's assertion is persuasive that historical spending in this program is not indicative of future spending because it is targeting a different asset type. As a result, the Commission finds PG&E's request for capital expenditures for MAT 48N Insulator Replacement to be reasonable.

For these reasons, the Commission finds PG&E's request for capital expenditures for the work tracked in Other Equipment Replacement Work reasonable as capital expenditures of $5.858 million for 2021, $19.608 million for 2022, and $17.218 million for 2023.

In summary, regarding MWC 48 Replace Substation Equipment, the Commission finds PG&E's request reasonable, for the reasons noted above, and adopts capital costs at $76.601 million for 2021, $96.588 million for 2022, and

[1440] Cal Advocates Opening Brief at 535.

[1441] Cal Advocates Opening Brief at 243-244.

[1442] PG&E Opening Brief at 543.

[1443] PG&E Opening Brief at 542-543.

$96.331 million for 2023. PG&E's expense forecast for MWC 48 was not contested and, as such, the Commission finds this expense forecast reasonable.

4.15.7. Electric Distribution Substation Transformer Replacements (MWC 54)

PG&E tracks work in MWC 54 Distribution Transformer Replacements that includes "proactive" transformer replacements of substation transformers, procurement of new emergency transformers or mobile equipment, and transformer reconditioning.[1444] The work that PG&E tracks in MWC 54 consists of the following two subcategories of capital expenditures: (1) MAT 54A Proactive Substation Transformer Replacements & Mobile Equipment and Capitalized Emergency Materials, and (2) MAT 54L Transformer Life Extension.[1445] PG&E's forecast for MAT 54L is uncontested and, as such, the Commission finds reasonable PG&E requests for capital expenditures of $0 in 2021, $3.2 million in 2022, and $3.25 million in 2023 for MAT 54L Transformer Life Extension. The work that PG&E tracks in MAT 54A includes two distinct activities: (1) Proactive Substation Transformer Replacements, and (2) Mobile Equipment and Capitalized Emergency Materials.[1446]

PG&E's capital expenditure request for the first subcategory of MAT 54A, Proactive Substation Transformer Replacements, is as follows: $32.2 million in 2021, $22.1 million in 2022, $16 million in 2023, $24 million in 2024, $28.5 million in 2025, and $31.3 million in 2026.[1447] PG&E states that its 2023 forecast is

[1444] PG&E Ex-04 at 15-31.

[1445] PG&E Ex-04 at 15-33.

[1446] PG&E Opening Brief at 545.

[1447] PG&E Ex-04 at 15-31.

$16.7 million less than 2020 recorded capital expenditures of $32.7 million.[1448] PG&E states that the decrease in 2023 as compared to 2020 is due to prioritization of a different type of work, namely breaker replacements. [1449]

PG&E's capital expenditure request for the second subcategory of MWC 54A, Mobile Equipment and Capitalized Emergency Materials, which maintains an inventory of emergency transformers, mobile transformers, and spare transformers for emergency response, is as follows: $8.7 million in 2021, $2.7 million in 2022, $2.0 million in 2023, $3.0 million in 2024, $42.5 million in 2025, and $3.9 million in 2026. PG&E's recorded 2020 capital expenditures were negative $0.8 million.[1450] PG&E did not purchase any emergency material in 2020 and received a credit from a prior procurement, which is reflected in the negative recorded amount.[1451]

Regarding the forecast for Proactive Transformer Replacements, which is part of the work tracked in MAT 54A, PG&E states that, in its 2020 GRC, it was in the process of shifting to a temporarily "just-in-time" replacement strategy for substation transformers to provide resources to pursue its other higher priority wildfire mitigation work.[1452] PG&E explains that its current replacement strategy is a "guard rail" strategy, which seeks to replace transformers to sustain a service list more in-line with industry standards.[1453] As explained by PG&E, its 2021 and

[1448] PG&E Ex-04 at 15-31 to 15-32.

[1449] PG&E Ex-04 at 15-31 to 15-32.

[1450] PG&E Ex-04 at 15-32 to 15-33.

[1451] PG&E Ex-04 at 15-32 to 15-33.

[1452] PG&E Ex-04 at 15-31.

[1453] PG&E Ex-04 at 15-31.

2022 forecast reflects completion of mostly in-flight work.[1454] Then, PG&E explains that its 2023 forecast is a decrease over 2020 recorded costs; however, the forecast will be used to initiate new transformer replacement projects during the rate case period.[1455] PG&E states that the decrease in funding in 2023 supports the reprioritization of funds to initiate breaker replacements.[1456] Additionally, PG&E explains that it plans to implement the guard rail approach for transformer replacements in anticipation of reaching transformer replacements system-wide each year to sustain an average expected service life aligned with industry standards.[1457] PG&E states that sustainable levels of replacement are needed to work in combination with mitigation measures tracked in MWC 54 to ensure system reliability.[1458]

Regarding PG&E's request for costs associated with the work tracked in MAT 54A Mobile Equipment and Capitalized Emergency Materials, Cal Advocates recommends $1.7 million for 2023 capital expenditures for this subprogram, which is $0.2 million lower than PG&E's proposal. Cal Advocates bases this recommendation on a reduced substation risk score of approximately 12.1% resulting in a reduced need, according to Cal Advocates, for emergency substation equipment of 12.1%.[1459] In response, PG&E states that Cal Advocates' reduction to this emergency program could limit PG&E's emergency readiness.

[1454] PG&E Ex-04 at 15-31.

[1455] PG&E Ex-04 at 15-31.

[1456] PG&E Ex-04 at 15-31.

[1457] PG&E Ex-04 at 15-31.

[1458] PG&E Ex-04 at 15-31.

[1459] Cal Advocates Opening Brief at 247.

AARP disputes PG&E's cost forecast for the work tracked in MAT 54A Proactive Transformer Replacements and recommends cost reductions totaling $99.806 million over the rate case period, 2023-2026.[1460] AARP states that PG&E's decision to rely on pre-emptive (or proactive) equipment replacement utilizes an unreasonable subjective assessment of an asset's age and condition, as opposed to using more objective methods that other similar utilities employ.[1461] AARP contends that PG&E's strategy for replacing these assets is profit driven, as fully depreciated equipment that remains in service earns no rate of return.[1462] In response, PG&E states that targeted proactive replacement of substation equipment is a reasonable and appropriate approach to the long-term management of its substation assets and that AARP's proposed forecast reductions would jeopardize the balance PG&E seeks to strike with its desired level of inventory and replacement strategy.[1463] PG&E also states that its planned transformer replacements have operational advantages that afford PG&E the ability to determine whether additional asset replacements should be added to the project scope to meet long term objectives to maintain safe and reliable service and, in contrast, emergency replacement does not offer this advantage.[1464]

The Commission does not agree with AARP that proactive replacement of assets should be completely disallowed. An objective and robust proactive replacement program for these types of assets is important to maintaining reliability and public safety because transformer outages at substations affect

[1460] AARP Ex-01 at 50.

[1461] AARP Ex-01 at 48.

[1462] AARP Ex-01 at 49.

[1463] PG&E Ex-17 (Rebuttal) at 15-27.

[1464] PG&E Ex-17 (Rebuttal) at 15-27.

large numbers of customers and tend to be high energy events, which can endanger the public and PG&E's workforce. Additionally, the Commission does not agree with Cal Advocates' reduced forecast because, in this instance, a reduction to this emergency program could limit PG&E's emergency readiness by resulting in PG&E having lower inventory levels to support transformer failures, which in turn would compromise PG&E's efforts to reduce risk through its proactive transformer replacement project. In this instance, waiting until the end of the asset's life or until asset failure to perform replacements could be risky and more costly because of supply chain issues and long lead times for this type of equipment. For these reasons, the Commission finds PG&E's requested capital expenditures forecast for 2021, 2022, and 2023 for work related to MAT 54A Distribution Transformer Replacements reasonable but finds the past relaxed approach to work in this area, under a "just-in-time" strategy, concerning, especially because PG&E's revised plan, the "guard rail" approach, appears to require a substantial amount of work to reduce risks, at a forecast of $3.2 million of work, to reach an acceptable level of risk for safety and reliability.

Accordingly, the Commission adopts capital expenditures of $40.766 million in 2021, $27.970 million in 2022, and $21.243 million in 2023 for MWC 54A and MWC 54L Distribution Transformer Replacements.

4.15.8. Electric Distribution Substation Safety and Security (MWC 58)

The work that PG&E tracks in MWC 58 Distribution Substation Safety and Security consists of four subprograms, tracked in four separate MAT codes.[1465] PG&E's forecast related to its work in two of the MAT codes is not contested,

[1465] PG&E Opening Brief at 547.

MAT 58B Seismic and MAT 58C Distribution Substation Miscellaneous Equipment (now discontinued).[1466]

PG&E's MAT 58A Fire Protection Suppression subprogram tracks work to install fire mitigations as required by local fire marshals and state regulations, and MAT 58S Security tracks work under the Distribution Substation Security subprogram, which installs, upgrades, or replaces physical security measures within substations.[1467] For the MAT 58A Fire Protection Suppression subprogram, PG&E requests capital expenditures of $1.7 million for 2021, $0 for 2022, $3.3 million in 2023, $3.3 million in 2024, $1.1 million in 2025, and $1.2 million in 2026, with the 2023 forecast representing a $0.7 million increase from PG&E's 2020 recorded capital expenditures of $2.6 million.[1468]

Cal Advocates recommends removing $1.6 million from PG&E's 2021 request for Fire Protection Suppression subprogram MAT 58A and moving it to the 2022 request because PG&E likely will spend less, approximately $1.6 million, for this subprogram in 2021.[1469] Cal Advocates also states that the reason for the increase includes PG&E's past reprioritization of work for this program, as well as ramping up this subprogram to meet insurance obligations based on third-party review.[1470] PG&E disagrees and states it is inappropriate to shift forecast funds that were not used in a particular MAT in 2021 to 2022 because 2022 is a separate forecast year and because PG&E routinely does less

[1466] PG&E Opening Brief at 547.

[1467] PG&E Opening Brief at 547; PG&E Ex-04 at 15-36 to 15-37.

[1468] PG&E Ex-04 at 15-36.

[1469] CALPA Ex-06 at 80.

[1470] Cal Advocates Opening Brief at 266, *citing to* PG&E Ex-04 at 15-36.

work than forecast in some MATs while doing more work than forecast in others.[1471]

The Commission finds that Cal Advocates' recommendation to reallocate forecast funds from 2021 to 2022 for the MAT 58A is unsupported. In addition, the Commission finds reasonable PG&E's capital expenditure request of $1.7 million for 2021, $0 for 2022, and $3.3 million in 2023 for the Fire Protection Suppression subprogram MAT 58A.

PG&E's Distribution Substation Security subprogram MAT 58S tracks work to install physical security measures within substations. PG&E's capital expenditure request is $3.2 million in 2021, $1.7 million in 2022, $5 million in 2023, $5.6 million in 2024, $4.6 million in 2025, and $0 in 2026.[1472] PG&E states that its 2023 forecast represents a $4.4 million increase from PG&E's 2020 recorded capital expenditures of $0.6 million.[1473] PG&E states that the reason for the increase is to replace fence installations for North American Electric Reliability Corporation (NERC)-defined low-impact distribution physical security sites. PG&E also states that sites are identified based on meeting the directives in D.19-01-018, the Commission's decision on physical security of electric utilities.[1474]

Cal Advocates recommends reducing PG&E's 2023 capital forecast for Distribution Substation Security subprogram MAT 58S because Cal Advocates does not find PG&E capable of the proposed pace of work since historically

[1471] PG&E Opening Brief at 548.

[1472] PG&E Ex-04 at 15-37.

[1473] PG&E Ex-04 at 15-37.

[1474] PG&E Ex-04 at 15-37, citing to D.19-01-018, Phase I Decision on Order Instituting Rulemaking Regarding the Physical Security of Electrical Corporations.

PG&E has performed less work in this area.[1475] Cal Advocates recommends reducing the forecast for 2023 from $5.0 million to $1.9 million based on PG&E's 2019-2021 average pace for this type of work.[1476]

The Commission finds that PG&E's below average pace of work in this area tracked in MAT 58S does not necessarily mean that PG&E's future work will not increase for Distribution Substation Security subprogram MAT 58S. In addition, the Commission finds that PG&E's past average pace of work does not necessarily meet the future needs for substation security and that the PG&E's forecast for Distribution Substation Security subprogram (MAT 58S) is consistent with its directives[1477] regarding substation security. Therefore, the Commission finds PG&E's capital expenditures request reasonable for MAT 58S Distribution Substation Security of $3.2 million in 2021, $1.7 million in 2022, and $5.0 million in 2023. Accordingly, the Commission adopts capital expenditures for MWC 58 Distribution Transformer Replacement of $5.980 million for 2021, $1.738 million for 2022, and $8.232 million for 2023.

4.16. Electric Distribution System Automation and Protection

PG&E presents a request for expense and capital expenditures for its Electric Distribution System Automation and Protection (DSAP) Program.[1478] PG&E states that the DSAP Program covers the installation, upgrade, and replacement of remotely controlled automation and protection equipment in

[1475] Cal Advocates Opening Brief at 249.

[1476] Cal Advocates Opening Brief at 249.

[1477] D.19-01-018; PG&E Ex-04 at 15-37.

[1478] PG&E Ex-04 at 16-1.

distribution substations.[1479] PG&E explains that it will shift the primary focus of the DSAP Program to replacing obsolete SCADA and protection equipment.[1480] According to PG&E, this work will improve operating efficiency, enable better outage response and diagnosis, improve system protection, and improve employee and public safety by enabling PG&E to automatically and remotely shut off electricity during emergencies as well as disabling circuit breaker reclosing during periods of high fire risk. [1481]

Expense work is tracked in MWC HX DSAP Support. [1482] PG&E's 2023 expense forecast of $3.008 million is uncontested.[1483] PG&E's 2020 recorded expense is $2.3 million.[1484] The key cost drivers for expense expenditures include overseeing substation automation projects; relaying and protecting all distribution substation assets; and deployment, operation, and maintenance of substation human-machine interfaces.[1485]

Capital work is tracked in MWC 09 Electric Distribution SAP.[1486] PG&E's capital expenditures request is $25.483 million in 2021, $26.371 million in 2022, $27.003 million in 2023, $27.745 million in 2024, $28.540 million in 2025, and $29.281 million in 2026.[1487] PG&E states that its 2023 capital forecast is

[1479] PG&E Ex-04 at 16-5.

[1480] PG&E Ex-04 at 16-5.

[1481] PG&E Ex-04 at 16-5.

[1482] PG&E Opening Brief at 549.

[1483] PG&E Opening Brief at 549. (Forecast does not include September 6, 2022 Update Testimony (PG&E Ex-33) escalation rates.)

[1484] PG&E Ex-04 at 16-1.

[1485] PG&E Ex-04 at 16-9 to 16-10.

[1486] PG&E Opening Brief at 549.

[1487] PG&E Opening Brief at 549; PG&E Ex-04 at 16-1. (Forecast does not include September 6, 2022 Update Testimony (PG&E Ex-33) escalation rates.)

$10.4 million or 28% lower than the 2020 recorded costs of $37.4 million.[1488] The key cost drivers for capital expenditures include a shift in primary program focus from the initial installation of SCADA equipment at a substation to the replacement of obsolete SCADA equipment, increasing the rate of replacement of relays at or near the end of their service life, and the failure rate of existing automation and protection equipment.[1489] PG&E's capital forecast is also uncontested.

The Commission finds the uncontested expense forecast for 2023 and capital expenditures requests for 2021, 2022, and 2023 reasonable.[1490] Accordingly, the Commission adopts expense forecast for MWC HX Electric Distribution SAP of $3.008 million for 2023 and capital expenditures for MWC 09 Electric Distribution SAP of $25.483 million in 2021, $26.371 million in 2022, and $27.003 million in 2023.

4.17. Electric Distribution Capacity, Engineering, and Planning

PG&E presents a request for an expense forecast and capital expenditure costs for the following two programs: (1) Engineering and Planning Program, and (2) Electric Distribution Capacity Program.[1491] For these two programs, PG&E tracks its expense in MWC FZ Electric Engineering and Planning, and PG&E tracks capital expenditures in MWC 46 Distribution Substation Capacity and MWC 06 Distribution Line Capacity.[1492]

[1488] PG&E Ex-04 at 16-1.

[1489] PG&E Ex-04 at 16-10, 16-11, 16-14, and 16-15.

[1490] PG&E Opening Brief, Appendix A at A-12 and A-23.

[1491] PG&E Ex-04 at 17-4.

[1492] PG&E Ex-04 at 17-6 and 17-7.

PG&E states that the Engineering and Planning Program supports a variety of asset management and operating activities and is necessary to plan, design, and operate PG&E's electric distribution system, including supporting the distribution system improvements required to meet commitments in PG&E's Wildfire Mitigation Plan.[1493] Regarding PG&E's Electric Distribution Capacity Program, PG&E states that this program is used to manage substation and distribution line investments necessary to meet customer demand.[1494]

PG&E's 2023 expense forecast for its Engineering and Planning Program is $19.943 million and is uncontested.[1495] PG&E's 2020 recorded expense for this program is $15.158 million.[1496] PG&E explains that this increase "is primarily due to escalation and additional Distribution Engineering headcount."[1497] PG&E also states that this program supports distribution system improvements required to "meet commitments" in PG&E's Wildfire Mitigation Plan.[1498] PG&E does not present a capital expenditure request for this program.

PG&E requests capital expenditures for the Electric Distribution Capacity Program of $286.313 million in 2021, $215.512 million in 2022, $195.7 million in

[1493] PG&E Ex-04 at 17-4 to 17-5.

[1494] PG&E Ex-04 at 17-4.

[1495] PG&E Opening Brief at 549. PG&E's TY 2023 forecast including the September 6, 2022 Update Testimony (PG&E Ex-33) escalation adjustment is $20.473 million. Expense work is tracked in MWC FZ Electric Engineering and Planning.

[1496] PG&E Ex-17 (Rebuttal) at 17-17.

[1497] PG&E Ex-04 at 17-19, stating "The increase in Distribution Engineering headcount is to facilitate local presence at the regional level and support increased workload which created the need for two additional engineering planning offices to improve local engineering presence and accountability."

[1498] PG&E Ex-04 at 17-5.

2023, $231.2 million in 2024, $248.3 million in 2025, and $262.2 million in 2026.[1499] PG&E's 2023 forecast is $52.2 million higher than its 2020 recorded costs of $143.5 million.[1500] PG&E states that the increase in capital expenditures is primarily driven by an increase in new applications for service and added loads that require capacity work to serve customers, especially in the areas of transportation electrification, internet-based distribution centers, data centers, high tech campuses, state and local infrastructure, agricultural well pumping, dairy bio digesters, and indoor cultivation.[1501] PG&E also states that work is driven by "a significant increase in overloaded transformer replacement program, and higher project costs."[1502] PG&E does not present an expense forecast for this program.

Several parties contest PG&E's capital expenditure request for the Electric Distribution Capacity Program, including Cal Advocates, TURN, and the Joint Community Choice Aggregators. As stated above, PG&E tracks costs related to its Electric Distribution Capacity Program in two Major Work Categories. PG&E explains that MWC 46 Distribution Substation Capacity tracks work to upgrade "within" distribution substations projected to have a capacity deficiency and MWC 06 Distribution Line Capacity tracks line work "outside" of the substations associated with capacity projects.[1503] PG&E tracks specific types of costs in a number of MAT codes under MWC 46 Distribution Substation Capacity and

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[1499] PG&E Ex-17 (Rebuttal) at 17-18; PG&E Ex-64 (JCE) at 2-298 and 4-107.

[1500] PG&E Ex-04 November 5, 2021 at 17-5.

[1501] PG&E Ex-04 at 17-5. PG&E provides unit costs at WP 17-32 (Table 17-27) and project costs in various tables. The unit cost of equipment and project costs include both labor and material. PG&E has not broken down and separated the labor costs for its capital expenditures.

[1502] PG&E Ex-04 at 17-8.

[1503] PG&E Ex-17 (Rebuttal) at 17-5.

MWC 06.[1504] PG&E explains that the key objectives of the Electric Distribution Capacity Program are to address: (1) capacity expansion necessary to meet customer demand growth; (2) potential equipment overload conditions; and (3) voltage and power factor compliance requirements.[1505] PG&E states that substation equipment upgrades are multi-year projects that require "three years or more to design, procure the necessary material, and construct, though some minor substation upgrades take less time."[1506] According to PG&E, new substations generally "take 5-7 years to build, due to permitting requirements."[1507]

PG&E provides more information about how it develops its workplan related to substations, as follows:

> System capacity deficiency projects identified during the forecasting process were part of the 2020 Distribution Investment Deferral Framework (DIDF) and were the basis for the 2020 Grid Needs Assessment (GNA) report issued by PG&E on August 15, 2020. These projects will appear again in the 2021 GNA report and be more fully developed and scoped than the newer emergent projects identified during the 2020 forecasting process. These emergent projects will be identified in the 2021 GNA report to be issued by PG&E on August 15, 2021. Emergent projects are identified in a separate section of the Chapter 17 workpapers, WP 17-21, lines 86-123 and WP 17-22, lines 86-123 and have rough dates, scope, and forecasted dollars associated with them. [1508]

[1504] PG&E Ex-17 (Rebuttal) at 17-5.

[1505] PG&E Ex-04 at 17-10.

[1506] PG&E Ex-17 at WP 17-51.

[1507] PG&E Ex-04 at 17-12.

[1508] PG&E Ex-04 at 17-11.

In updates to PG&E's initial application on June 30, 2021, PG&E states it revised its capital request for its Electric Distribution Capacity Program to remove costs associated with a contract with Tesla to build the utility-owned Renz Energy Storage project.[1509] Removal of the capital forecasts equates to reduction in MAT 46A (Normal Capacity Deficiencies) by $26.287 million in 2021 and $0.154 million in 2022.[1510] PG&E states that it terminated the contract and has removed the 2021 and 2022 capital forecasts associated with this project.[1511]

PG&E's request for capital expenditures for this program, including both MWC 06 and MWC 46, together with the recommended reductions to PG&E's request by Cal Advocates, TURN, and Joint Community Choice Aggregators are summarized below.

Table 4-L:
Capital Summary MWC 46 & MWC 06 (Thousands of Nominal Dollars)[1512]

Program	2020 Recorded Adjusted	2021 Recorded Adjusted	Party	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
MWC 46 Distribution Substation Capacity	$36.270	$54.216	PG&E	$52.593	$65.036	$58.082	$68.061	$71.985	$74.728
			TURN	--	--	$45.748	--	--	--
			Cal Advocates	$52.593	$64.439	$54.599	--	--	--
MWC 06 Distribution Line Capacity	$107.255	$157.046	PG&E	$233.720	$150.476	$137.655	$163.173	$176.314	$187.492
			TURN	--	--	$119.245	--	--	--
			Cal Advocates	$190.139	$111.054	$122.728	--	--	--
Total	**$143.525**	**$211.262**	**PG&E**	**$286.313**	**$215.512**	**$195.737**	**$231.234**	**$248.299**	**$262.219**
			TURN	**--**	--	**$164.993**	--	--	--

[1509] PG&E Ex-17 (Rebuttal) at 17-1; PG&E Ex-17 (Rebuttal) at 17-9, in which PG&E indicates that it is not necessary to subtract $26.3 million from PG&E's 2021 forecast for MAT 46A and add it to PG&E's 2023 forecast because PG&E has cancelled the Renz Energy Storage project and has removed these 2021 and 2022 capital forecasts. PG&E also indicates $0 forecast on Table 17-16 at PG&E Ex-17 (Rebuttal) at WP 17-16.

[1510] PG&E-17 (Rebuttal) at 17-19 (Table 17-6).

[1511] PG&E Ex-17 (Rebuttal) at 17-1.

[1512] PG&E Ex-64 (JCE) at 2-296 to 2-298 and 4-10 (reflecting removal of Renz Energy Storage project).

Program	2020 Recorded Adjusted	2021 Recorded Adjusted	Party	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
			Cal Advocates	$242.732	$175.493	$177.327	--	--	--

Cal Advocates proposes a reduction to PG&E's 2022 forecast for MAT 06H New Business-Related Capacity Work due to PG&E's lower than expected historical spending in 2021. Cal Advocates notes that in 2021 PG&E spent significantly less than its forecast for MAT 06H. According to Cal Advocates, PG&E explained this variance, stating as follows: "Estimating, Dependency and Construction resources diverted to higher priority work (Wildfire Mitigation Plan and High Fire Threat District Tag Initiative)."[1513] Cal Advocates states that, because similar resource shortages are likely to affect 2022 work, the Commission should reduce PG&E's forecast accordingly.[1514] PG&E responds that the existence of lower spending in 2021 does not indicate lower spending will occur in 2022 for this cost category and that the opposite is possible as incomplete work is carried over from 2021 into 2022, increasing the need for 2022 funding. [1515] In addition, PG&E explains that since the 2023 forecast was finalized by PG&E, PG&E has received numerous new applications for service that will require capacity work to serve, including a significant increase in applications for service partly due to increased demand for electric vehicle charging.[1516] The Commission does not find Cal Advocates' recommended reduced forecast due to lower spending in 2021 for MAT 06H persuasive because the data was filed after PG&E's June 30, 2021 GRC.

[1513] Cal Advocates Opening Brief at 252-256.

[1514] PG&E Opening Brief at 551.

[1515] PG&E Opening Brief at 551.

[1516] PG&E Opening Brief at 551.

Cal Advocates also recommends proposed reductions to the forecasts related to MAT 46H New Business-Related (Includes Emergent Work) and MAT 06H New Business-Related Capacity Work because, according to Cal Advocates, the operational date of PG&E's Garberville Project is delayed.[1517] Cal Advocates explains that the Garberville Circuit and Substation Reinforcement Project (also known as the Garberville Project) represents the highest capital expenditure forecast for a proposed electric distribution capacity project in this rate case period (2023-2026).[1518] Cal Advocates states that PG&E presents a forecast of capital expenditures of $53.907 million that are reflected in the forecasts for years 2022, 2023, and 2024.[1519] Cal Advocates explains that, according to PG&E's June 30, 2021 Application, PG&E stated that the Garberville Project was expected to be operational on June 1, 2024.[1520] However, based on information obtained by Cal Advocates during this rate case, Cal Advocates suggests that the scope of the project is not well-defined and will likely be expanded, which will result in only certain portions of the project being operational by June 1, 2024.[1521] As a result, Cal Advocates recommends a reduction to the capital expenditure forecast to remove the Garberville Project by the following amounts: $14.927 million from MWC 06H and $3.483 million from MWC 46H.[1522] In response, PG&E states that since PG&E filed its June 30, 2021 Application, several projects have become necessary due to new loads in the

[1517] Cal Advocates Opening Brief at 275-276.

[1518] Cal Advocates Opening Brief at 275.

[1519] Cal Advocates Opening Brief at 275-276.

[1520] Cal Advocates Opening Brief at 276.

[1521] Cal Advocates Opening Brief at 276.

[1522] Cal Advocates Opening Brief at 256-258.

Garberville area, including a line work project to reconductor overhead line on the Newbury and Rio Dell circuits and installing new overhead line to support additional substation capacity at Rio Dell Substation.[1523] PG&E states that if there are changes to the Garberville project timeline that result in lower spending in 2023, the unused amount would be deployed to the Garberville project in the attrition years or to the other Garberville area capacity projects described above, or to other emergent capacity projects during the rate case period, such as large electric vehicle projects.[1524] The Commission finds Cal Advocates' recommendation unpersuasive as PG&E's forecast New Business-Related Capacity (MAT 06H and MWC MAT 46H) accommodates potential changes in the Garberville Project while also incorporating changing demands on the system by other Garberville area capacity projects and demands related to electric vehicle charging.

TURN recommends a reduction in PG&E's 2023 capital forecast for MAT 06A Feeder Projects Associated With Substation Work, MAT 06H New Business-Related Capacity Work, MAT 46A Normal Capacity Deficiencies, and MAT 46H New-Business (Includes Emergent Work) associated with agricultural load.[1525] In support of this recommendation, TURN states that its recommendation takes into account the likely effect of new time-of-use rates on the forecast peak demand driven by agricultural load.[1526] TURN states further that the impact of time-of-use rates, which were implemented in March of 2021, was not reflected in the historical peak data from 2016-2020 used to forecast

[1523] PG&E Opening Brief at 552.

[1524] PG&E Opening Brief at 552.

[1525] TURN Opening Brief at 468.

[1526] TURN Opening Brief at 469-483; TURN Reply Brief at 117-118.

future circuit peak loads.[1527] In response, PG&E states that the additional applications PG&E has received for new service since filing its 2023-2026 forecast would more than offset the amount of TURN's recommended reductions due to time-of-use rates.[1528] The Commission finds the evidence of emergent capacity needs presented by PG&E persuasive and provides justification for its forecast. The recommendation by TURN of a 50% reduction could result in insignificant funding of capacity projects needed to respond to currently identified and emergent capacity needs.[1529] The Commission finds TURN's recommendation does not justify a reduction in PG&E's forecast, and PG&E has established that sufficient capacity projects are needed and supported by the forecast. Nevertheless, the Commission takes note of TURN's finding that "including the 'catch-up' work of 2021-2022, the average expenditures in 2016-2022 were $106 million. PG&E is thus forecasting a 50% increase in annual spending for distribution capacity investments, even accounting for the completion of work deferred due to 'reprioritization' in 2016-2020."[1530]

Joint Community Choice Aggregators argue that the Commission must consider "cost causation" issues and properly align costs with either distribution or generation.[1531] Joint Community Choice Aggregators provide, as an example, the now withdrawn Renz Energy Storage project and suggest that the project cost for battery-related projects should not be entirely placed on distribution

[1527] TURN Opening Brief at 469-483; TURN Reply Brief at 117-118.

[1528] PG&E Opening Brief at 554.

[1529] TURN Opening Brief at 476.

[1530] TURN Opening Brief at 468.

[1531] Joint Community Choice Aggregators Opening Brief at 8-9.

customers since it also serves the needs of generation customers.[1532] The Commission will consider this issue in a rate design proceeding.

Accordingly, for the reasons stated above, the Commission adopts capital expenditures for Electric Distribution Capacity Program (MWC 46 and MWC 06) of $286.313 million in 2021, $215.512 million in 2022, and $195.7 million in 2023. The Commission also adopts the uncontested 2023 expense forecast of $19.943 million (MWC FZ).

4.18. New Business and Work at The Request of Others

PG&E identifies a number of factors driving the need for additional investments in its electric operations, including distribution upgrades in order to serve increased customer load, new connections, and electric vehicle charging infrastructure investments in support of the state's goals for vehicle electrification.[1533] PG&E presents an expense forecast and capital expenditures for the New Business and Work At The Request Of Others Program.[1534] PG&E states that its New Business and Work At The Request Of Others Program consists of the following: (1) (New Business) installing electric infrastructure required to connect new customers to PG&E's distribution system and accommodating increased load from existing customers; (2) (Work at the Request of Others) relocating PG&E's existing electric facilities, including underground of existing overhead electric facilities, at the request of customers and governmental agencies under the provisions of PG&E's Electric Rule 20B and Electric

[1532] Joint Community Choice Aggregators Opening Brief at 9.

[1533] PG&E Opening Brief at 3-4.

[1534] PG&E Ex-04 at 18-1.

Rule 20C;[1535] and (3) customer contact, design and engineering, job cost estimation, contract preparation, construction, inspection of third-party work, and facility mapping.[1536]

PG&E's 2023 expense forecast for the New Business and Work At The Request Of Others Program is $24.161 million.[1537] PG&E's 2020 recorded expense is $28.507 million. PG&E's 2023 expense forecast tracked in MWC EV and MWC EW is uncontested.[1538] The Commission finds this expense request reasonable.

PG&E's request for capital expenditures for the New Business and Work at the Request of Others Program is as follows: $667,558 for 2021, $745,170 for 2022, $781,194 for 2023, $841,719 for 2024, $913,712 for 2025, $978,178 for 2026.[1539] PG&E's recorded capital expenditure for 2020 is $681,819.[1540]

PG&E tracks costs related to the New Business and Work At The Request Of Others Program in the following two Major Work Categories: (1) MWC 10 Electric Distribution Work At the Request Of Others General, and (2) MWC 16 Electric Distribution Customer Connects.[1541]

PG&E's capital forecast for work in MWC 10 includes costs for upgrading two substations to allow for continued electrification of Caltrain's transportation system. The Commission addressed this forecast as part of Track 2 of this

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1535 PG&E Ex-04 at 18-1 to 18-2.

1536 PG&E Ex-04 at 18-1 to 18-2.

1537 PG&E Ex-04 at 18-2 and 18-3.

1538 PG&E Opening Brief at 554-555; PG&E Ex-04 at 18-2.

1539 PG&E Ex-17 (Rebuttal) at 18-4 (Table 18-3).

1540 PG&E Ex-04 at 18-4 and WP 18-17.

1541 PG&E Ex-04 at 18-4.

proceeding and in this decision as part of the Settlement of Track 2.[1542] As stated in Section 15, herein, regarding the January 6, 2023 Settlement, the Commission finds the costs presented for PG&E's Substation Upgrades related to Caltrain reasonable. Furthermore, as directed by D.20-05-008, the Commission reaffirms the 60% (PG&E)-40% (Caltrain) cost allocation approved by the Commission in D.20-05-008. Accordingly, the Commission adopts a total of $8.176 million for the Caltrain Project to be added to PG&E's rate base and recovered in revenue requirement beginning in 2023. No party contested this settlement provision. After addressing the issues pertaining to Caltrain, no party opposes PG&E's remaining forecast for MWC 10 Electric Distribution Work at the Request Of Others General. The Commission finds the forecast for work tracked in MWC 10 Electric Distribution Work at the Request of Others General reasonable, as set forth in Section 4.18.

Regarding PG&E's forecast for the work tracked in MWC 16 Electric Distribution Customer Connects, several parties dispute the capital expenditure forecast. PG&E tracks work in MWC 16 Electric New Business that consists of installing the electric infrastructure required to connect new customers to PG&E's distribution system or to accommodate increased load from existing customers.[1543] PG&E's capital expenditure request for MWC 16 Electric New Business is as follows: $511.868 million for 2021, $600.122 million for 2022, $648.425 million for 2023, $701.877 million for 2024, $762.885 million for 2025,

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[1542] October 1, 2021 Assigned Commissioner's Scoping Memo and Ruling at 4; January 6, 2023 Joint Motion of Pacific Gas and Electric Company and The Public Advocates Office at the California Public Utilities Commission for Approval of a Settlement of Track 2 Issues at 1.

[1543] PG&E Ex-04 at 18-10.

and $801.837 million for 2026.[1544] PG&E's 2020 recorded capital expenditure is $536.190 million.[1545] PG&E states that expenditures for 2023 are forecast to increase by approximately $130 million (or 24%) over PG&E's 2020 recorded expenditures, mainly driven by forecasted increased demand for residential customer connections and service upgrade and infrastructure work related to increased load from electric vehicles.[1546]

The parties recommend reductions in four areas of MWC 16, as follows: (1) Residential Connects, (2) Non-Residential Connects, (3) Plug-in Electric Vehicles; and (4) Transformer Purchases.[1547] The Commission addresses these four topics within MWC 16 below.

4.18.1. Residential Connects

PG&E's Residential Connects includes the costs of building new underground and overhead primary electric distribution systems, and the associated secondary systems and services to residential customers.[1548] PG&E's 2023 forecast for Residential Connects is $261.565 million based on its projection of 57,434 new connections, which PG&E expects to increase during the attrition years.[1549] By comparison, PG&E's for 2020 (recorded) is $197 million based on actual 2020 connection of 41,521 units.[1550] PG&E states that, consistent with the 2017 and 2020 GRCs, the new connects forecast was developed using an

[1544] PG&E Ex-04 at 18-4.

[1545] PG&E Ex-04 at 18-4; PG&E Ex-17 (Rebuttal) at 18-4.

[1546] PG&E Ex-04 at 18-11.

[1547] PG&E Ex-17 (Rebuttal) at 18-4; PG&E Ex-04 at 18-10.

[1548] PG&E Opening Brief at 554-556.

[1549] PG&E Ex-04 at 18-27; PG&E Opening Brief at 483.

[1550] PG&E Ex-04 at 18-27; PG&E Opening Brief at 483.

economic model developed by Rosen Consulting Group, an independent real estate economics consulting firm that specializes in California and Bay Area markets.[1551] The Rosen Consulting Group model analyzes PG&E historic connects data in relation to historic leading indicator data using a multiple linear regression technique.[1552] The primary variables for residential connections are residential permitting and employment growth.[1553] PG&E multiplies its forecast number of new connections by a unit cost in each year to determine PG&E's cost forecast.[1554]

Regarding Residential Connects MWC 16, TURN recommends a lower 2023 forecast for residential new connections on the basis that PG&E's forecast is overly optimistic and higher than historical amounts.[1555] TURN contends that PG&E's expectation of significantly increased demand for residential permits in coming years is based on Rosen Consulting Group's assumptions of real estate demand in PG&E's service territory, which has changed since June 2021 when PG&E submitted its GRC application.[1556] TURN contends that it was unable to fully research its theory because PG&E did not provide TURN with access to the consultant's model and inputs used to forecast new permits, claiming the information was proprietary and owned by a third-party, Rosen Consulting Group.[1557]

[1551] PG&E Ex-04 at Ch. 18, in Attachment A, Rosen Consulting Group (RCG), *Evaluation of PG&E 2023 GRC Utility Connects Rebuttals (2022)* at 1-5.

[1552] PG&E Reply Brief at 482-483.

[1553] PG&E Ex-17 (Rebuttal) at 18-8.

[1554] PG&E Ex-17 (Rebuttal) at 18-8.

[1555] TURN Opening Brief at 485.

[1556] TURN Opening Brief at 486.

[1557] TURN Opening Brief at 486.

TURN engaged in its own analysis, which resulted in a lower forecast of residential permits.[1558] TURN suggests the Rosen Consulting Group's analysis is flawed because it fails to account for the lack of labor and supplies to meet the demand for new housing in PG&E's service territory.[1559] TURN applied the five-year 2015-2019 annual permit growth rate (8.9% for single family and 9.1% for multifamily) to the five-year 2015-2019 average of annual permits to estimate residential permits in test year 2023.[1560] TURN does not oppose PG&E's unit costs for residential connections.[1561] TURN applied PG&E's unit costs and connection allocation methodology to the modified regression model results to produce a forecast for residential new electric connections of 45,599 in 2023 (in contrast to PG&E's estimate of 57,434 in 2023).[1562] TURN explains that its lower residential permit forecast results in a recommendation of $207.668 million for 2023 (in contrast to PG&E's forecast of $261.565 million in 2023).[1563] TURN explains that its forecast allows for growth over recent recorded data but is aligned with the pre-COVID trajectory in new housing connections and the more reasonable assumption of ongoing constraints to building new residential housing in California, particularly over the near term.[1564]

For similar reasons, Cal Advocates disputes PG&E's forecast for Residential Connects and recommends reducing PG&E's forecast for Residential

[1558] TURN Ex-08 at 13-14.

[1559] TURN Ex-08 at 13-14.

[1560] TURN Ex-08 at 16.

[1561] TURN Opening Brief at 485.

[1562] TURN Ex-08 at 16; TURN Opening Brief at 487.

[1563] TURN Ex-08 at 16.

[1564] TURN Ex-08 at 16.

Connects by $89.232 million for 2021 and $2.484 million for 2022 (PG&E's request was $167.496 million in 2021 and $238.545 million for 2022).[1565]

In response, PG&E supports its Residential Connects MWC 16 forecast by pointing to the increased need for housing and a more development-friendly legislative environment as drivers for an increased rate of permitting.[1566]

The Commission finds that, since the specifics of Rosen Consulting Group's model are not provided, it is difficult to determine how the model might accommodate economic impacts of the COVID-19 pandemic in the 2020-2021 years and the changes in California housing regulation and funding that have attempted to ease the housing crisis in California. Nevertheless, the Commission is not persuaded by the analysis of TURN or Cal Advocates because the state has adopted regulatory changes to speed up the permitting process in an effort to address the state's housing shortage. For these reasons, even though the Rosen Consulting Group's model provides little insight, the Commission finds PG&E's Residential Connects MWC 16 forecast aligns with the goal of the state to promote increased growth in residential permits. For these reasons, the Commission finds PG&E's forecast for Residential Connects MWC 16 reasonable.

4.18.2. Non-Residential Connects

PG&E's Non-Residential Connects activity is also tracked in MWC 16.[1567] PG&E states that Non-Residential Connects captures the costs of building new underground and overhead primary electric distribution systems, the associated secondary systems, and services to non-residential customers.[1568] PG&E's

[1565] Cal Advocates Opening Brief at 280-285.

[1566] PG&E Ex-04 at 18-12.

[1567] PG&E Ex-17 (Rebuttal) at 18-13.

[1568] PG&E Ex-17 (Rebuttal) at 18-13.

forecast for non-residential connects follows the same process as the forecast for residential connects except that subcategories are not used.[1569] The forecast number of connects is based on the Rosen Consulting Group model.[1570] Unit costs are based on historical three-year averages (2018-2020), adjusted to nominal 2020 dollars.[1571]

Regarding Non-Residential Connects MWC 16, Cal Advocates disputes PG&E's capital forecasts for connecting new non-residential customers to PG&E's electrical system.[1572] PG&E's 2023 capital expenditures forecast is $192.848 million.[1573] Cal Advocates is not confident in the recommendations by the Rosen Consulting Group because its resulting connection forecasts have consistently differed from the actual number of connections.[1574] Cal Advocates claims that PG&E's connection forecasts are an unreliable foundation for predicting new connections and recommends an alternative that increases PG&E's 2022 and 2023 capital forecast for residential connects.[1575] Cal Advocates analyzed PG&E's historical connections data and adjustment factors, developed by Cal Advocates, which it applied to PG&E's new connections forecast to arrive at its forecast that is slightly higher than PG&E's forecast in those same years.[1576]

[1569] PG&E Ex-04 at 18-28.

[1570] PG&E Ex-04 at 18-28.

[1571] PG&E Ex-04 at 18-28.

[1572] Cal Advocates Opening Brief at 262.

[1573] PG&E Ex-04 at 18-29.

[1574] Cal Advocates Opening Brief at 265.

[1575] Cal Advocates Opening Brief at 263.

[1576] PG&E Opening Brief at 556.

In response, PG&E states that the Non-Residential capital funding levels recommended by Cal Advocates are not enough for PG&E to complete the amount of non-residential connection work that its models predict will be necessary in the rate case period.[1577]

Similar to the above regarding Residential Connects, the Commission finds that, since the specifics of Rosen Consulting Group's model are not provided regarding Non-Residential Connects, it is difficult to determine how the model might accommodate economic impacts of the COVID-19 pandemic in the 2020-2021 years and changes in California housing regulation and funding that have attempted to ease the housing crisis in California. Nevertheless, the Commission is not persuaded by the analysis of TURN or Cal Advocates because evidence shows an increased trend in Non-Residential Connects that TURN and Cal Advocates did not address. For these reasons, the Commission finds reasonable PG&E's forecast for Non-Residential Connects MWC 16.

4.18.3. Plug-In Electric Vehicles-Related Upgrade Costs

PG&E states that Plug-In Electric Vehicles, which is tracked in MWC 16, reflects costs of all distribution transformer, secondary and service upgrade work to serve increased loads related to Plug-In Electric Vehicles.[1578] PG&E explains that the portions of the capital expenditure forecast that are relevant to this discussion (rather than other parts of PG&E's forecast) are the utility-side distribution costs ("to the meter") related to PG&E's Electric Vehicle Charge 2 Application [A.21-10-010].[1579] PG&E describes this work as including electric

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[1577] PG&E Ex-17 (Rebuttal) at 18-15.

[1578] PG&E Opening Brief at 560.

[1579] PG&E Opening Brief at 560.

distribution infrastructure, such as trenching, concrete, and electrical wires on the utility side of the meter, previously funded by third-party non-residential customers, and includes other upgrades.[1580] PG&E requests a 2023 capital expenditure forecast of $21.691 million.[1581] PG&E's 2020 recorded capital expenditure is $19.277 million.[1582]

TURN recommends that PG&E's 2023 capital forecast for the Electric Vehicle Charge 2 portion of MWC 16 be reduced to align with the number of charging ports that PG&E is authorized by the Commission in the Electric Vehicle Charge 2 Application proceeding.[1583] TURN states that PG&E's forecast for utility-side infrastructure costs related to its Electric Vehicle Charge 2 Application, A.21-10-010, assumes a different number of charging ports and different deployment timeline than PG&E presented in its Electric Vehicle Charge 2 application, with a much smaller number of charging ports and no deployment costs in TY 2023.[1584] TURN states that PG&E's GRC forecast should be modified to incorporate the number of charging ports ultimately authorized by the Commission in the Electric Vehicle Charge 2 proceeding.[1585]

On May 12, 2023, PG&E filed a Petition for Modification of D.22-12-054, "requesting that D.22-12-054 be modified to allow PG&E not to implement Phase 1 of the EVC 2 program, because to implement the program under the

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[1580] PG&E Ex-04 at 18-13.

[1581] PG&E Ex-17 (Rebuttal) at 18-4 (Table 18-2, Line 6 and Table 18-3 summarizes the adjustment of $(18,370) at the MWC 16 level); PG&E Ex-04 at 18-32 presents initial request of $40.061 million.

[1582] PG&E Ex-04 at 18-32.

[1583] TURN Ex-08 at 2-4.

[1584] PG&E Ex-08 at 2-5.

[1585] PG&E Ex-08 at 2-5.

approved budget would be infeasible or result in a severe reduction of total ports installed."[1586] The Commission understands that PG&E's forecast for utility-side infrastructure costs related to its EVC 2 application, in the context of this GRC, may be called into question by PG&E's request in its Petition for Modification, and thus finds it prudent not to address PG&E's revenue requirement request until more certainty has been established regarding this matter. Accordingly, the Commission declines to adopt a 2023 capital expenditure forecast for Plug-In Electric Vehicles MWC 16 and defers to the ongoing proceeding where PG&E filed its Petition for Modification for consideration of EVC 2's scope and budget.

4.18.4. Distribution Transformer Purchases

PG&E explains that it purchases all the distribution transformers that are installed as part of any capital project under New Business Program MWC 16.[1587] PG&E explains that transformers are revolving stock and the transformer forecast includes not only transformers installed in New Business projects but also transformers used to replace transformers that fail in the field, transformers used in relocation work, and transformers used as part of conversion of overhead to underground facilities.[1588] PG&E requests capital expenditures of $141.570 million in 2021, $151.725 million in 2022, and 169.068 million in 2023.[1589] PG&E also requests specific forecasts for 2024, 2025, and 2026.[1590] PG&E's 2020 recorded capital expenditure is $107.281 million.[1591]

[1586] May 12, 2023 PG&E Petition for Modification of D.22-12-054 at 3.

[1587] PG&E Ex-04 at 18-13.

[1588] PG&E Ex-04 at 18-14.

[1589] PG&E Ex-04 at 18-34.

[1590] PG&E Ex-04 at 18-34.

[1591] PG&E Ex-04 at 18-34.

Cal Advocates recommends a forecast for capital expenditure that is $30.014 million lower than PG&E's forecast for 2021, $23.052 million lower for 2022, and $12.057 million lower for 2023.[1592] Cal Advocates' lower forecast for these years is based on adjustments in other capital expenditure categories: Pole Replacements (MWC 07), New Business (MWC 16) and Major Emergency (MWC 95).[1593]

In response, PG&E states that Cal Advocates' recommended reduction for Distribution Transformer Purchases should not be adopted because the other proposed reductions – to MWC 07 and MWC 95 – upon which it depends should not be adopted.

The Commission does not agree with Cal Advocates' analysis because the Commission did not adopt any corresponding reductions to Pole Replacements (MWC 07), New Business (MWC 16) and Major Emergency (MWC 95) to justify the reduction requested by Cal Advocates. The Commission finds PG&E's recommendation for capital expenditures of $141.570 million in 2021, $151.725 million in 2022, and $169.068 million in 2023 reasonable regarding Distribution Transformer Purchases.

4.19. Tariff Rule 20A

Traditionally, when PG&E performs work to underground its electrical infrastructure in response to requests by governmental agencies, for aesthetic reasons or to address traffic concerns, the work is referred to as Rule 20A undergrounding work.[1594] The guidelines for this program are outlined in PG&E's Electric Tariff Rule 20A. The Commission in D.21-06-013 made

[1592] Cal Advocates Opening Brief at 280.

[1593] Cal Advocates Opening Brief at 280 and 290.

[1594] PG&E Ex-04 at 19-1.

modifications to the Tariff Rule 20A program.[1595] D.23-06-008, issued on June 13, 2023, closed R.17-05-010 and discontinued the Rule 20A and Rule 20D program.[1596] PG&E's work in the Electric Rule 20A Program is not related to PG&E's proposed forecast to underground its infrastructure for purposes of wildfire ignition mitigation.

PG&E uses MWC IG to record expense items for the Electric Rule 20A Program and does not request an expense forecast but intends to record actual costs in its Rule 20A Balancing Account, for which PG&E will later request recovery.[1597] PG&E's 2019 recorded adjusted amount was $1.219 million.[1598] PG&E's capital expenditures forecast is $47.288 million in 2021, $39.954 million in 2022, $39.876 million in 2023, $40.957 million in 2024, $42.060 million in 2025, and $43.204 million in 2026.[1599] These capital costs are tracked in MWC 30.[1600] PG&E's 2022 forecast is based on a three-year average (2018-2020).[1601] In addition, PG&E proposes to continue its one-way balancing account, the Rule 20A Balancing Account, through 2026.[1602] Specifically, PG&E requests that the "carry-over of any over-collected balances for use in future projects be continued in the 2023 GRC."[1603] PG&E estimates a $32.7 million balance in the Rule 20A balancing

[1595] D.21-06-013, *Phase 1 Decision Revising Electric Rule 20 and Enhancing Program Oversight* (June 3, 2021).

[1596] D.23-06-008, *Phase 2 Decision Revising Electric Rule 20 and Establishing Local and Tribal Government Consultation Requirements* (June 8, 2023)

[1597] PG&E Ex-04 at 19-1.

[1598] PG&E Ex-04 at 19-10.

[1599] PG&E Opening Brief at 562.

[1600] PG&E Opening Brief at 562.

[1601] PG&E Opening Brief at 562.

[1602] PG&E Ex-04 at 2-10 and 19-1.

[1603] PG&E Ex-04 at 19-8.

account at the end of 2022 that will be available to fund projects in the 2023 general rate case period, should this carry-over function be re-authorized.[1604]

TURN recommends a reduction in PG&E's capital expenditure forecast for the Electric Rule 20A Program of approximately $11 million annually from 2022–2026.[1605] TURN determined its recommendation by first using the recorded 2021 capital figure to adopt a forecast for 2022 using a five-year average.[1606] Next, TURN recommends that the forecasted amount for 2022-2026 be reduced by the accumulated balance in the one-way balancing account, which TURN states is consistent with the treatment adopted in SCE's recent GRC decision, D.21-08-036.[1607]

In response, PG&E contends that its use of the three-year (2018-2020) average instead of a five-year average (2017-2021) is more reasonable for the following reasons: (1) PG&E's recorded costs increased every year from 2017 to 2019; 2020 and 2021 recorded costs, while lower than 2019 recorded costs, were still much higher than both 2017 and 2018 costs; (2) TURN's use of a five-year average starting in 2017 gives too much weight to PG&E's relatively low spending in 2017 and 2018; (3) PG&E's three-year (2018-2020) average more accurately represents the direction of the program and is more consistent with PG&E's 2021 spending of $37.8 million than TURN's approach; (4) the entire balance of the existing Rule 20A balancing account should not be spent down by the end of 2026 because PG&E's forecast already accounts for a spend down of a

[1604] TURN Opening Brief at 497.

[1605] TURN Ex-15 at 5.

[1606] TURN Ex-15 at 5.

[1607] TURN Opening Brief at 497.

significant portion of the balancing account balance; (5) PG&E has many more potential Rule 20A projects in the queue than it currently has the resources to complete; (6) adopting TURN's proposal would make the problem of the backlogged projects worse due to even less access to needed resources; (7) any remaining funds in the balancing account will provide flexibility to perform more project work than forecast if resources become available; and (8) SCE's recent GRC decision, D.21-08-036, should not be followed because PG&E has a much larger number of Rule 20A projects in its queue than SCE does.[1608]

The Commission finds TURN's use of a five-year (2017-2021) average accounts for price changes over time and offers the more reasonable forecast. However, none of the above proposals adequately addresses PG&E's history of underspending relative to forecast for Rule 20A conversion projects and whether Rule 20A funds are being cost-effectively spent. The parties, for example, provide no analysis of Rule 20A metrics of the cost per mile converted. Accordingly, the Commission adopts a forecast of $37.8 million for 2021, $28.2 million for 2022, and $29.2 million for capital expenditures in 2023 for MWC 30 Electric Rule 20A.

4.20. Electric Distribution Data Management and Technology

PG&E's forecast for the following Major Work Categories for Electric Distribution are set forth in PG&E Ex-04, ch. 20: (1) MWC GE Electric Distribution Mapping (expense), and (2) MWC JV (expense) and MWC 2F (capital) Information Technology is set forth in.[1609] PG&E tracks additional capital expenditures under MWC 21 Miscellaneous Capital.[1610] The combined

[1608] PG&E Opening Brief at 563-564.

[1609] PG&E Ex-04 at 20-1.

[1610] PG&E Ex-04 at 20-3.

total capital forecast for MWC 2F and MWC 21 of $17.696 million for 2021, $23.605 million for 2022, and $19.700 for 2023 is uncontested.[1611] Two expense forecasts are contested, MWC GE Electric Distribution Mapping and MWC JV Information Technology, which are discussed below. In addition, Cal Advocates requests modifications to PG&E's Project Estimating Tool (PET), which is used to estimate most of PG&E's Information Technology-related project costs.[1612] The Commission addresses the disputes regarding PET, MWC GE Electric Distribution Mapping, and MWC JV Information Technology, below.

4.21. PG&E's Project Estimating Tool

Building on concerns stated in prior GRCs, Cal Advocates recommends that the Commission direct PG&E to make PET more transparent and easier to analyze.[1613] PG&E claims that the changes recommended by Cal Advocates are not necessary for demonstrating the viability and accuracy of the PET and Cal Advocates' recommendations are based on a fundamental misunderstanding of the purpose of the PET.[1614]

Cal Advocates states that 15 of 17 estimates produced by PET and provided by PG&E to Cal Advocates included manual overrides for the labor component of the project and that PG&E does not provide enough information to allow parties to validate PG&E's justification for these manual overrides.[1615] Cal Advocates recommends the Commission require PG&E to (1) provide a comparison of past PET estimates after adjustment versus actual project costs in

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[1611] Cal Advocates Opening Brief at 272; PG&E Reply Brief at 490.

[1612] PG&E Reply Brief at 490.

[1613] Cal Advocates Opening Brief at 273-278.

[1614] PG&E Reply Brief at 491-492.

[1615] Cal Advocates Opening Brief at 273-275.

each subsequent GRC filing, (2) provide more detail on PET estimates relating to its last GRC and data on PET estimates relating to all past rate cases, (3) provide a justification in workpapers for each manual override explaining what factors cause the manual override to more accurately estimate costs, (4) propose revisions to the PET that would cause it to take into account the factors at hand, and (5) identify the internal processes and authorities that support initiating and approving manual overrides.[1616]

In response, PG&E states PET provides a standard, consistent estimating approach across all its IT projects using a documented assumption-driven methodology and, in addition, that PET is not a proxy for a detailed job estimates or business cases because it represents an investment estimate at a high level and a specific point in time.[1617] PG&E states that it is not viable to provide an analysis comparing PET analysis to actual project costs due to the differing level of assumptions and the passage of time, PET cannot accommodate all factors used to produce a final project estimate, and that PG&E may not even retain the initial manual overrides in the execution of the project.[1618] PG&E further states that it does not create a resource plan to more precisely determine contractor labor versus internal labor until later in project development but provides assurance that PG&E continues to make improvements to PET and it will disclose any significant changes to the Commission.[1619]

Considering the above, the Commission finds it reasonable to direct PG&E, in future GRCs, to provide an explanation and workpaper justification,

[1616] Cal Advocates Opening Brief at 275-276.

[1617] PG&E Reply Brief at 491.

[1618] PG&E Reply Brief at 492.

[1619] PG&E Reply Brief at 492.

for each manual override performed on PET estimates, which at a minimum explain why the PET manual override more accurately estimates costs. The Commission finds that the information provided by PG&E in such explanations and workpapers may inform future improvements and visibility into PET analysis.

4.21.1. Electric Distribution Mapping

PG&E states that the work of Electric Distribution Mapping involves the maturation of capabilities and management of core data quality and systems/platforms (e.g., GIS, SAP AG Software (SAP), and Foundry) to provide asset information that is accurate, traceable, verifiable, and complete and to enable effective data-driven decisions for asset and risk management.[1620] PG&E groups the activities in MWC GE Electric Distribution Mapping into four categories: Base Mapping, GIS Technical Enhancements, GIS Asset Data Improvements, and Data Management and Analytics activities.[1621] For MWC GE Electric Distribution Mapping, PG&E's expense forecast is $21.524 million in 2023.[1622] PG&E's 2020 recorded adjusted expense is $8.845 million.[1623] The below chart indicates PG&E's recorded expense and forecasted expense for each category of MWC GE Electric Distribution Mapping, as follows:

[1620] PG&E Opening Brief at 565.

[1621] Cal Advocates Opening Brief at 289.

[1622] PG&E Opening Brief at 565.

[1623] PG&E Opening Brief at 565.

Table 4-M:
MWC GE – Electric Distribution Mapping Expense Forecast Details ($1,000)[1624]

Program	2020 Recorded	2021 Recorded	Party	2021 Forecast	2022 Forecast	2023 Forecast
Base Mapping	$1,430	N/A	PG&E	$1,640	$1,640	$391
GIS Technical Enhancements	$711	N/A	PG&E	$900	$900	$6,765
GIS Asset Data Improvements	$2,552	N/A	PG&E	$8,991	$8,991	$9,115
Data Management and Analytics	$4,152	N/A	PG&E	$6,500	$4,723	$5,253
Forecast Adjustment	$0	N/A	PG&E	($2,143)	($2,146)	$0
Total MWC GE	**$8,845**	**N/A**	**PG&E**	**$15,888**	**$14,108**	**$21,524**

Cal Advocates recommends a 2023 forecast for MWC GE Electric Distribution Mapping of $8.845 million, which corresponds to PG&E's 2020 recorded expense.[1625] In support of its recommendation, Cal Advocates states that $8.845 million forecast for 2023 is higher than PG&E's recorded figures in the years 2016 to 2019 and $12.679 million less than PG&E's requested 2023 forecast of $21.524 million.[1626] Cal Advocates' recommendation is based on PG&E's repeated deferral of the Field Asset Inventory, an electric distribution mapping project (which is now known as the Next Gen GIS project), for which PG&E requested funding in the 2014, 2017, and 2020 GRCs but PG&E deferred its work.[1627]

[1624] PG&E Ex-04 at WP 20-7 (Table 20-7).

[1625] Cal Advocates Opening Brief at 289.

[1626] Cal Advocates Opening Brief at 289.

[1627] CALPA Ex-04 at 34; Cal Advocates Opening Brief at 288-290.

PG&E states its 2023 forecast for MWC GE Electric Distribution Mapping is significantly higher than 2020 recorded costs primarily due to the required implementation of PG&E's Next Gen GIS project beginning in 2023, as well as an increased number of updates to the asset registry stemming from PG&E's implementation of enhanced inspections.[1628] In addition, PG&E states it anticipates higher costs in 2023 to implement the electric data strategy, which will be led by PG&E's Data Management and Analytics organization.[1629] Lastly, PG&E denies that forecasted amounts should be removed for deferring the previously funded Field Asset Inventory project because PG&E cancelled the Field Asset Inventory project and performed other valuable work instead.[1630]

The Commission finds that PG&E has failed to support the entirety of its 2023 expense request of $9.115 million for the GIS Asset Data Improvements project, specifically the Next Gen GIS project (previously known as the Field Asset Inventory project), which is component of PG&E's forecast for MWC GE Electric Distribution Mapping. The Commission's finding is based on questions raised by Cal Advocates on the lack of supporting information and PG&E's repeated reallocation and deferral of previously authorized revenue requirement in PG&E's 2014, 2017, and 2020 GRCs for the Field Asset Inventory project.[1631] However, the Commission finds that it is reasonable to adopt $5.2 million of PG&E's $9.115 million 2023 expense forecast for the four components of the GIS Asset Data Improvements project that are unrelated to the historic Field Asset

[1628] PG&E Opening Brief at 566.

[1629] PG&E Opening Brief at 566.

[1630] PG&E Opening Brief at 565-567.

[1631] Cal Advocates Opening Brief at 288-290; PG&E Opening Brief at 565-567.

Inventory efforts.[1632] The 2023 expense requests for these four unrelated components of the GIS Asset Data Improvements project are $0.5 million for streetlight inventory, $2.7 million for underground facilities inventory, and $2.0 million combined for Request for Work map corrections and the development, implementation, and maintenance of critical features in GIS.[1633]

No parties disputed PG&E's 2023 expense forecasts for these other categories in MWC GE Electric Distribution Mapping, which are as follows: $0.391 million for Base Mapping, $6.765 million for GIS Technical Enhancements, and $5.253 million for Data Management and Analytics. These categories in MWC GE Electric Distribution Mapping are separate and unrelated to the historic Field Asset Inventory efforts.[1634]

As such, the Commission reduces PG&E's 2023 forecast for MWC GE Electric Distribution Mapping of $21.524 million by $3.915 million for the Next Gen GIS project component of the GIS Asset Data Improvements that PG&E failed to justify as reasonable. This reduction is calculated as the difference between PG&E's total 2023 expense request of $9.115 million for GIS Asset Data Improvements and the $5.2 million for the portions of the 2023 expense request for the four components that are unrelated to the historic Field Asset Inventory efforts, as described above. This results in a total 2023 expense forecast for MWC GE Electric Distribution Mapping of $17.609 million: $0.391 million for Base Mapping, $6.765 million for GIS Technical Enhancements, $5.253 million for Data Management and Analytics, and $5.2 million for the adequately supported portions of GIS Asset Data Improvements. Accordingly, the Commission finds

[1632] PG&E Opening Brief at 566; PG&E Ex-17 (Rebuttal) at 20-6.

[1633] PG&E Ex-04 at WP 20-23 to WP 20-25.

[1634] PG&E Opening Brief at 566; PG&E Ex-17 (Rebuttal) at 20-6.

reasonable and adopts a reduced forecast for 2023 for Electric Distribution Mapping (MWC GE) of $17.609 million.

4.21.2. Maintain Information Technology and Applications and Infrastructure

PG&E's work reflected in MWC JV Maintain IT Applications and Infrastructure includes the portfolio technology investments needed to improve capabilities related to asset and work management, customer service, and billing and rates.[1635] PG&E used the IT PET to forecast the "vast majority of IT-related projects and programs."[1636] For MWC JV Maintain IT Applications and Infrastructure, PG&E forecasts expense of $4.501 million for 2023. The below chart indicates PG&E's expense forecast for MWC JV Maintain IT Applications and Infrastructure, as follows:

Table 4-N:
MWC JV – Maintain and Operate Applications and Infrastructure Expense Forecast Details ($1,000)[1637]

Program	2020 Recorded	2021 Recorded	Party	2021 Forecast	2022 Forecast	2023 Forecast
Asset Management & Risk Analysis	$1,455	N/A	PG&E	$444	$420	$372
Billing & Rates	$69	N/A	PG&E	$44	$100	$100
Customer Service	$0	N/A	PG&E	$273	$199	$120
Data Enablement	$27	N/A	PG&E	$448	$0	$0
Enterprise Resource Management	$406	N/A	PG&E	$0	$0	$0
Event Management	$51	N/A	PG&E	$0	$0	$0

[1635] PG&E Opening Brief at 567.

[1636] PG&E Ex-04 at 20-39.

[1637] PG&E Ex-04 at WP 20-7 (Table 20-8).

Program	2020 Recorded	2021 Recorded	Party	2021 Forecast	2022 Forecast	2023 Forecast
Field Work Management	$132	N/A	PG&E	$785	$1,158	$2,267
IT Electric Distribution Non-WF NPAE	$669	N/A	PG&E	$700	$700	$701
Safety, Gov, Reg, Compliance	$0	N/A	PG&E	$1,084	$756	$941
System Operation & Control	$0	N/A	PG&E	$0	$0	$0
Total MWC JV	**$2,810**	**N/A**	**PG&E**	**$3,777**	**$3,333**	**$4,501**

PG&E states it prepared a bottom-up expense forecast for MWC JV based on the types of projects that PG&E anticipates during this GRC period (2023-2026).[1638] For example, PG&E states that its 2023 expense forecast for the Field Work Management value stream was $2.2 million more than 2020 recorded due to "increased investment in expanded digitization of design and estimating toolsets and the development of software tools for new service application work-planning and scheduling."[1639]

For MWC JV Maintain IT Applications and Infrastructure in 2023, Cal Advocates recommends $1.062 million less than PG&E's forecast.[1640] Cal Advocates' recommendation is based on a three-year average of PG&E's 2018-2020 recorded adjusted expenses.[1641] Cal Advocates claims that its recommendation better addresses the variability in PG&E's information technology expenses, historic practice of reallocating its authorized revenues and

[1638] PG&E Opening Brief at 567.

[1639] PG&E Opening Brief at 567-568.

[1640] Cal Advocates Opening Brief at 310.

[1641] Cal Advocates Opening Brief at 310.

because PG&E underspent on such information technology in 2019 and 2020 by more than the reductions recommended by Cal Advocates, which PG&E states it reallocated to support wildfire mitigation programs.[1642]

The Commission finds PG&E's budget-based expense forecast anticipated for 2023 of $4.501 million to be persuasive and more appropriate, in this instance, than Cal Advocates historic three-year average. Furthermore, the need for PG&E's Electric Distribution Information Technology projects is not disputed. For these reasons, the Commission finds PG&E's 2023 forecast to be reasonable and adopts an expense forecast for MWC JV Maintain IT Applications and Infrastructure in 2023 of $4.501 million.

4.22. Integrated Grid Platform and Grid Modernization Plan

PG&E's requested 2023 expense forecast is $38.593 million for Integrated Grid Platform and Grid Modernization.[1643] PG&E's requested capital expenditure forecast is $220.390 million in 2021, $192.917 million in 2022, $131.655 million in 2023, $88.981 million in 2024, $42.163 million in 2025, and $43.438 million in 2026.[1644]

PG&E's Integrated Grid Platform (IGP) refers to three projects: the Advanced Distribution Management System (ADMS), the Distributed Energy Resource Management System (DERMS), and the IGP Information Technology Infrastructure projects.[1645] PG&E's Grid Modernization projects include Distribution Engineering Planning Tools, the Community Microgrid Enablement

[1642] Cal Advocates Opening Brief at 290-291.

[1643] PG&E Opening Brief at 568.

[1644] PG&E Opening Brief at 568.

[1645] PG&E Ex-04 at 21-2 to 21-3

Program (CMEP), the Electric Emerging Technology Program, and the Elkhorn Battery Energy Storage System.[1646]

PG&E tracks its work referred to as the Integrated Grid Platform and Grid Modernization Plan in five expense Major Work Categories: MWC AB Miscellaneous Expense, MWC AT Electric Emerging Technology Program, MWC HG Electric Transmission Operations Engineering and Technology, MWC IG Manage Various Balancing Account Processes, and MWC JV Maintain Information Technology Applications and Infrastructure. The following four 2023 expense forecasts are uncontested: MWC AB –$14.661 million, MWC HG – $15.541 million, MWC IG – $3.026 million, and MWC JV – $3.309 million.[1647]

PG&E tracks its Integrated Grid Platform and Grid Modernization Plan capital expenditures in six capital Major Work Categories: MWC 21 Miscellaneous Capital, MWC 2F Information Technology Capital, MWC 3M Smart Grid Pilot Program, MWC 3R Energy Storage Capital, MWC 63 Electric Distribution Operations Technology, and Transmission Interconnection MWC 82. PG&E's capital expenditure forecasts are presented in Table 4-O, below. PG&E's capital expenditure forecasts (but not recorded capital costs) for MWC 3R Energy Storage Capital are confidential.[1648]

[1646] PG&E Ex-04 at 21-3.

[1647] PG&E Opening Brief at A-12.

[1648] CALPA Ex-06-E at 102.

Table 4-O:
Integrated Grid Platform and
Grid Modernization Plan Capital Expenditures ($1,000)[1649]

MWC	MWC Description	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
21	Miscellaneous Capital	$2,882	$3,083	$2,237	$1,852	$1,902	–
2F	Information Technology Capital	$19,540	$17,900	$20,369	$19,086	$19,695	$17,000
3M	Smart Grid Pilot Program	–	–	–	–	–	–
3R	Energy Storage Capital	Confidential	Confidential	$4,092	$12,954	–	–
3R	Errata Adjustment	–	–	($4,092)	($12,954)	–	–
63	Electric Distribution Operations Technology	$81,885	$126,880	$109,049	$68,042	$20,565	$26,438
82	Transmission Interconnection	$121	–	–	–	–	–
Total Capital Forecast		**$104,428 excluding confidential MWC 3R**	**$147,863 excluding confidential MWC 3R**	**$131,655**	**$88,981**	**$42,163**	**$43,438**

The following five capital Major Work Categories are uncontested: MWC 21, MWC 2F, MWC 3M, MWC 3R, and MWC 82.[1650] Cal Advocates does not propose any adjustments to PG&E's MWC 3R forecast, although Cal Advocates presents a recommendation for MWC 3R regarding the date that

[1649] PG&E Ex-04 at WP 21-6, Table 21-6.

[1650] PG&E Opening Brief at 568.

certain infrastructure assets for this program should be considered in-service.[1651] In response, PG&E agrees that the operative date should and will be changed to align with the date the project was released to operations and will use the operative date of April 7, 2022.[1652]

4.22.1. Electric Emerging Technology Program (MWC AT)

PG&E forecasts $17.174 million in expense for its 2023 MWC AT Electric Emerging Technology Program.[1653] PG&E states that the program will support a series of external innovation partnerships to keep PG&E informed of the external technology landscape and industry trends, and facilitate coordination with industry, academia, and other external groups to identify and apply technology solutions that "address PG&E's greatest challenges."[1654] PG&E's Electric Emerging Technology Program in MWC AT includes activities to identify and develop emerging technologies with the following three components: (1) Emerging Technology Projects;[1655] (2) External Innovation Partnerships; and (3) Emerging Technology Program Administration.[1656]

PG&E states, "If the IOUs are authorized in R.19-10-005 to continue administering their respective EPIC Programs, PG&E will withdraw this program from consideration in the 2023 GRC."[1657] In November 2021, the

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[1651] CALPA Opening Brief at 278.

[1652] PG&E Ex-17 (Rebuttal) at 21-17.

[1653] Cal Advocates Opening Brief at 293.

[1654] PG&E Opening Brief at 569.

[1655] After the Commission approved PG&E's continued administration of the EPIC Program in D.21-11-028, PG&E removed the entire 2023 expense forecast of $15.1 million for the Emerging Technology Projects component of MWC AT.

[1656] Cal Advocates Opening Brief at 293.

[1657] PG&E Ex-04 at 21-28.

Commission issued a decision providing authorization to PG&E, SCE, and SDG&E to continue in their role as administrators of the EPIC Program.[1658] PG&E's Electric Emerging Technology Program is funded through the EPIC Program.[1659] Based on this alternative funding, Cal Advocates recommends that the Commission remove the 2023 Electric Emerging Technology Program cost of $17.174 million from the 2023 GRC forecast.[1660] Cal Advocates states that PG&E's forecasts of $17.174 million (MWC AT) for its 2023 Electric Emerging Technology Program is already funded through EPIC in proceeding R.19-10-005.[1661]

In D.21-11-028, the Commission authorized the energy utilities to continue their role as administrators of the EPIC program.[1662] The Commission finds that, in response to D.21-11-028, PG&E removed $15.1 million for the Technology Demonstration Project Work.[1663] This $15.1 million removal was the entire 2023 expense forecast for the Emerging Technology Projects component of MWC AT. PG&E further confirms that the remainder of its request of $2.056 million reflects its forecast for the External Innovation Partnership subprogram and its administration, which is not funded through EPIC.[1664] Cal Advocates does not provide a rationale for de-funding the External Innovation Partnerships program in MWC AB.[1665] Therefore, based on these statements by PG&E, confirming the

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[1658] Cal Advocates Opening Brief at 293.

[1659] Cal Advocates Opening Brief at 293.

[1660] Cal Advocates Opening Brief at 293.

[1661] Cal Advocates Opening Brief at 293.

[1662] PG&E Ex-17 (Rebuttal) at 21-16.

[1663] PG&E Ex-17 (Rebuttal) at 21-15 to 21-16; PG&E Opening Brief at 569.

[1664] PG&E Opening Brief at 569.

[1665] PG&E Opening Brief at 569 and PG&E Ex-17 (Rebuttal) at 21-16.

removal of $15.1 million from its forecast and Cal Advocates having not explicitly addressed the forecast for the External Innovation Partnerships subprogram, the Commission finds PG&E's reduced 2023 expense forecast of $2.056 million for MWC AT Electric Emerging Technology Program is reasonable. Accordingly, the Commission adopts the 2023 expense forecast for MWC AT Electric Emerging Technology Program of $2.056 million.

4.22.2. Advanced Distribution Management System and Distributed Energy Resources Management System (Capital MWC 63)

PG&E requests $81.885 million in 2021, $126.88 million in 2022, $108.074 million in 2023, and $64.037 million in 2024 for its Advanced Distribution Management System (ADMS), which reflect costs to develop this new software that is related to modernizing its electric infrastructure and improved safety.[1666] PG&E explains that this new software is needed, reasoning that: "To support PG&E's objective of providing secure, reliable, and resilient electricity that enables continued gains for clean energy technology and California's economy in a way that gives our customers value, flexibility, and choice in how they use energy, PG&E needs to continue to improve its existing infrastructure and invest in new technologies."[1667] PG&E further explains that, "The ADMS will become PG&E's core distribution operations technology tool to enable the visibility, control, forecasting, and analysis of a more dynamic grid. Greater visibility and control of the grid are needed for PG&E to continue providing safe and reliable service to customers in the face of the increasing complexity of the grid due to DER adoption, the apparent 'new normal' of

[1666] PG&E Ex-04 at 21-1 and 21-22.

[1667] PG&E Ex-04 at 21-1.

weather-related emergencies, evolving California energy policy requirements, and increasing cyber-security threats."[1668]

PG&E also proposes to build a Distributed Energy Resource Management System (DERMS) to complement the foundational technology improvements and grid management tools built by the ADMS Program.[1669] PG&E forecasts capital expenditures in MWC 63 of $0.975 million in 2023, $4.005 million in 2024, $20.565 million in 2025, and $26.438 million in 2026 for its DERMS proposal.[1670]

PG&E's total capital forecast for MWC 63 Electric Distribution Operations Technology is the sum of its ADMS forecast and its DERMS forecast: $81.882 million in 2021, $126.88 million in 2022, and $109.049 million in 2023. Cal Advocates contests PG&E's capital forecast for MWC 63 related to the ADMS and the DERMS. The Commission addresses the arguments by Cal Advocates below.

4.22.3. Reduction to Forecast for ADMS Release 3 and DERMS (Capital MWC 63)

Cal Advocates recommends removing the capital forecast related to ADMS Release 3 and DERMS, which total $27.735 million in 2023,[1671] from this GRC due to the interrelated nature of PG&E's ADMS and DERMS to the Commission's separate and ongoing proceeding to *Modernize the Electric Grid for a High*

[1668] PG&E-04 at 21-19; PG&E Opening Brief at 570, stating that its ADMS project will replace the existing Real-Time Supervisory Control and Data Acquisition (RT-SCADA), Outage Management System (OMS), and Distribution Management System (DMS) control center applications.[1668] PG&E divides the ADMS project into several workstreams including three "releases" that support different functionality, with Release 1 to replace RT-SCADA, Release 2 to replace OMS, and Release 3 to enable advanced applications within the ADMS platform.

[1669] PG&E Ex-04 at 21-22.

[1670] PG&E Ex-04 at 21-24.

[1671] PG&E Ex-04 at WP 21-12 (Table 21-12).

Distributed Energy Resources Future, R.21-06-017.[1672] Cal Advocates states that consideration of these grid modernization projects and costs is more appropriate in a proceeding dedicated to distributed energy resources, such as R.21-06-017.[1673]

PG&E disagrees with Cal Advocates and claims that ADMS Release 3 and DERMS should not be removed from the GRC because moving the issue to R.21-06-017 will cause unnecessary delay in implementation and the topic is not significantly related to the topics being considered by the Commission in that rulemaking proceeding.[1674]

The Commission finds that coordination with the High Distributed Energy Resources Future proceeding, R.21-06-017, could result in increased scrutiny of the functionalities of ADMS and DERMS. However, in D.18-03-023, the Commission determined that software, such as the ADMS Release 3 and DERMS, could be included in PG&E's grid modernization plans in the GRC for review and evaluation.[1675] The Commission stated, "The investor-owned utilities (IOUs), in their General Rate Case (GRC) filings on grid modernization, shall use the tools developed in the Distribution Resources Plan proceeding to present the level of distributed energy resource penetration system integration challenges that are expected to arise on the grid, and what the most cost-effective mitigation options or investments are."[1676] Therefore, the Commission finds that, consistent

[1672] CALPA Ex-06 at 106.

[1673] Cal Advocates Opening Brief at 281 and 286.

[1674] PG&E Opening Brief at 571-573.

[1675] D.18-03-023, *Decision on Track 3 Policy Issues, Sub-Track 2 (Grid Modernization)* (March 22, 2018) at 34 (OP 4).

[1676] D.18-03-023, *Decision on Track 3 Policy Issues, Sub-Track 2 (Grid Modernization)* (March 22, 2018) at 34 (OP 4).

with the direction in D.18-03-023, it is appropriate to consider the costs of the $27.735 million in this GRC.

Accordingly, the Commission denies the removal of the cost of ADMS 3 and DERMS from PG&E's request and Cal Advocates' recommended reduction of $27.735 million for PG&E's 2023 forecast for ADMS Release 3 and DERMS associated with their proposed removal.

4.22.4. ADMS Release 1 and Release 2 (Capital MWC 63)

Cal Advocates does not oppose the Commission's consideration of PG&E's forecasts for ADMS Releases 1 and 2 in this proceeding on the basis that these software releases are not as closely tied to distribution energy resources integration.[1677] However, Cal Advocates recommends reducing ADMS Releases 1 and 2 capital expenditures forecast from $73.2 million to $48.3 million, a reduction of $24.9 million, based on PG&E's 2020 GRC forecast because PG&E fails to describe any functionality changes from 2020 to 2023 for ADMS Releases 1 and 2 or how any added functionality justifies the increased forecast over its 2020 forecast.[1678]

Cal Advocates recommends limiting PG&E's capital expenditures for the ADMS Releases 1 and 2 to a rate of spending based on PG&E's 2020 GRC forecast.[1679] Cal Advocates calculates an increase in PG&E's 2018-2024 ADMS (excluding DERMS) capital expenditure forecast from PG&E's 2020 GRC to its 2023 GRCs to be between $164.6 million and $303.6 million.[1680] Cal Advocates

[1677] Cal Advocates Opening Brief at 281–282.

[1678] Cal Advocates Opening Brief at 286.

[1679] Cal Advocates Opening Brief at 286.

[1680] Cal Advocates Opening Brief at 283, table titled *Comparison of ADMS Capital Expenditure Forecasts in PG&E's 2020 and 2023 General Rate Case Applications ($000's)*.

calculates PG&E's 2018-2024 ADMS (excluding DERMS) capital expenditure forecast in PG&E's 2020 GRC to be between $138.951 million and $277.902 million and in PG&E's 2023 GRC to be $442.506 million.[1681] In support of its proposed reduction, Cal Advocates states that the increase in total ADMS capital program costs are over 60% greater between PG&E's 2020 and 2023 GRCs and this increase is not supported by an increase in program scope and is not justified by PG&E.[1682] In addition, Cal Advocates states that PG&E's forecasted $442.5 million in ADMS capital expenditures is significantly more than SCE's forecasted $250 million in ADMS capital expenditures, which the Commission approved in the 2021 GRC.[1683]

In response, PG&E agrees with Cal Advocates that the ADMS Release 1 and Release 2 scope is largely unchanged.[1684] However, PG&E states that the ADMS program forecast should not be constrained by a cost estimate made in the early stages of the project.[1685] PG&E contends that the increase is supported by the complex and customized nature of the legacy Outage Management System (OMS) applications; the initial estimate being made in 2017, before the selection of a software vendor or detailed program design; and that the 2023 cost is well within PG&E's "high-cost case" scenario, which PG&E presented in the 2020 GRC, of $484.7 million.[1686] Lastly, PG&E asserts that if its forecast is

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[1681] Cal Advocates Opening Brief at 283, table titled *Comparison of ADMS Capital Expenditure Forecasts in PG&E's 2020 and 2023 General Rate Case Applications ($000's)*.

[1682] Cal Advocates Opening Brief at 283.

[1683] PG&E Opening Brief at 573-574.

[1684] PG&E Opening Brief at 575.

[1685] PG&E Opening Brief at 574.

[1686] PG&E Ex-17 (Rebuttal) at 21-14; PG&E Opening Brief at 574 -575.

reduced, the work on ADMS Release 2 would be delayed until revenue requirement for this work is approved in a future GRC.[1687]

The Commission finds PG&E's position persuasive that ADMS is a key component of its grid modernization effort and that a reduced forecast could delay the functionality, which could be detrimental to a high DER future.[1688] For these reasons, the Commission does not reduce PG&E's capital expenditure forecast for 2023 for the ADMS program by the $24.9 million recommended by Cal Advocates. The Commission adopts PG&E's capital expenditure forecast for ADMS and DERMS (MWC 63) of $81.882 million in 2021, $126.88 million in 2022, and $109.049 million in 2023.

4.23. Electric Distribution Support

PG&E states that Electric Distribution Support includes various activities that support the overall operation, development, and maintenance of the electric distribution system.[1689] PG&E's TY 2023 expense forecast is $131.594 million.[1690] PG&E's 2020 recorded expense is $99.2 million.[1691] PG&E tracks expense work in four MWCs, three of which are uncontested, MWC IS (Streetlight Support), MWC OM (Operational Management) and OS (Operational Support).[1692] Cal Advocates contests the forecast for MWC AB Miscellaneous Expense and recommends a forecast of $23.167 million.[1693]

[1687] PG&E Opening Brief at 575.

[1688] PG&E Ex-17 (Rebuttal) at 21-15.

[1689] PG&E Ex-04 at 22-4.

[1690] PG&E Opening Brief at 579; PG&E Ex-04 at 22-2.

[1691] PG&E Ex-04 at 22-1.

[1692] PG&E Opening Brief at 579; PG&E Ex-04 at 22-2.

[1693] Cal Advocates Opening Brief at 315.

PG&E's capital expenditures forecast is $(18.340) million in 2021, $10.663 million in 2022, $8.394 million in 2023, $8.575 million in 2024, $8.762 million in 2025, and $8.956 million in 2026.[1694] PG&E tracks capital work in the following two Major Work Categories: (1) MWC 05 Tools and Equipment, and (2) MWC 21 Miscellaneous Capital.[1695] PG&E's capital forecast is uncontested.

4.23.1. Miscellaneous Expense (Expense MWC AB)

PG&E's forecast for MWC AB Miscellaneous Expense within Electrical Distribution Support is contested by Cal Advocates.[1696] PG&E's expense forecast is $49.510 million for 2023.[1697] PG&E's 2020 recorded adjusted expense is $47.1 million.[1698] PG&E states that its forecast for MWC AB covers work performed across electric operations programs that is not easily captured by other MWCs.[1699] This includes activities such as service contracts with third parties, asset data and risk model improvements, costs related to PG&E's Applied Technology Services workstream, and regulatory and quality assurance efforts.[1700] PG&E states that the quality assurance efforts address data requests,

[1694] PG&E Opening Brief at 576; PG&E Ex-04 at 22-1 and 22-4. PG&E states that the 2021 forecast of $(18.3) million is comprised of a positive forecast of $5.2 million in MWC 05 and a negative amount of $23.5 million in MWC 21.

[1695] PG&E Opening Brief at 579; PG&E Ex-04 at 22-2.

[1696] PG&E Opening Brief at 576.

[1697] PG&E Opening Brief at 577.

[1698] PG&E Ex-04 at 22-12.

[1699] PG&E Opening Brief at 576.

[1700] PG&E Opening Brief at 376.

self-reports of non-conformance, incident investigation, compliance management, and compliance governance.[1701]

Cal Advocates claims that PG&E's 2023 forecast is based on PG&E's 2020 recorded adjusted costs, which are excessively high, which results in an inflated forecast for 2023.[1702] Cal Advocates recommends a reduction of PG&E's 2023 forecast for MWC AB of $26.343 million to $23.167 million based on a five-year average of PG&E's 2016-2020 recorded adjusted expenses.[1703]

In response, PG&E states that its forecast is not based on 2020 but, instead, on a "bottoms-up" approach.[1704] PG&E states that its increase in 2020 recorded costs over its 2020 forecast is based on the following: (1) incremental miscellaneous Distribution Support costs related to higher costs for planned outage mailings, an expansion of process improvement work, consulting costs, and other miscellaneous work; (2) higher 2020 Applied Technology Services costs associated with special projects related to wildfire risk, mitigation, and Applied Technology Services safety/reliability maintenance; (3) costs associated with executing Master Permits and Easements with the Forest Service in 2019, such as a roads inventory and road work; and (4) costs of PG&E's Regulatory Compliance and Quality Assurance Group, which was created in 2019.[1705]

The Commission is not persuaded by PG&E's forecast for Miscellaneous Expense. The Commission finds Cal Advocates' recommendation to rely on a five-year average convincing. While PG&E explains how Miscellaneous Expense

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[1701] PG&E Opening Brief at 577.

[1702] Cal Advocates Opening Brief at 316.

[1703] Cal Advocates Opening Brief at 314-315.

[1704] PG&E Opening Brief at 577.

[1705] CALPA Ex-04 at 41.

has evolved to support a "bottoms-up" expense forecast for 2023, PG&E provides insufficient information to substantiate its forecast for 2023 Miscellaneous Expense, which is over twice the average recorded cost of 2016-2019. PG&E provides a quantitative explanation for one component of its 2023 forecast for MWC AB, a budget of $17.1 million for the Regulatory Compliance and Quality Assurance Group. However, PG&E's quantitative explanation does not meet PG&E's burden to support its requested 2023 MWC AB Miscellaneous Expense forecast.

In short, the Commission finds that PG&E fails to explain how one year of data is not anomalous and, as a result, fails to justify an increase in MWC AB Miscellaneous, Electrical Distribution Support Expenses, compared to five years of data. Accordingly, the Commission adopts a lower 2023 forecast for MWC AB Miscellaneous Expenses, Electrical Distribution Support Expenses, based on a five-year average, $23 167 million.

4.24. Community Rebuild Program

PG&E's Community Rebuild Program refers to a discrete project, rebuilding both electric and gas infrastructure after the 2018 Camp Fire in and around the Town of Paradise, and costs associated with the Butt Wildfire rebuild. In 2018, the Town of Paradise was destroyed by the Camp Fire, a catastrophic wildfire ignited by PG&E equipment failures.[1706] The 2018 Camp Fire destroyed approximately 199 miles of PG&E's electric distribution lines and 34 miles of PG&E's gas pipeline.[1707] PG&E states it initiated the Community Rebuild Program in 2019, which PG&E describes as work to "rebuild PG&E's distribution

[1706] TURN Opening Brief at 500.

[1707] PG&E Opening Brief at 578.

electric and gas system infrastructure following the 2018 Camp Fire," which devastated the Town of Paradise and surrounding areas in Butte County.[1708] When re-building the electric infrastructure, PG&E states that it plans to underground all electric distribution assets in the Town of Paradise and adjacent parts of Butte County to support safety and city planning efforts.[1709]

PG&E's Community Rebuild Program is different from its 10,000-mile undergrounding proposal, also incorporated into this proceeding. PG&E describes the difference between these two initiatives as follows:

> What is the difference between the System Hardening Undergrounding Program and the Community Rebuild Program? In July 2021, PG&E announced a multi-year program to underground 10,000 distribution circuit miles in and near HFTDs to address California's growing wildfire risk. The 10,000 mile undergrounding program includes certain Community Rebuild work. In 2019, PG&E initiated the Community Rebuild Program to rebuild PG&E's distribution electric and gas system infrastructure following the 2018 Camp Fire, which devastated the Town of Paradise and surrounding areas in Butte County. As described in Exhibit (PG&E-4), Chapter 23, the Community Rebuild effort includes two different categories of electric underground mainline construction. The first category are the activities to restore underground mainline where the service was underground prior to the fire and that PG&E has an obligation to restore or where the underground mainline work is located in non-HFTD areas. The second category covers activities for underground construction of electric distribution assets in Tier 2 or Tier 3 HFTD areas that were previously overhead and are being transitioned to underground.[1710]

[1708] PG&E Ex-04 at 23-1.

[1709] PG&E Opening Brief at 578.

[1710] PG&E Ex-17 (Rebuttal) at 4.3-9 to 4.3-10. (fn. omitted.)

PG&E explains that cost recovery for Community Rebuild Expenditures for 2019-2020 excludes costs disallowed by the Wildfire Order Instituting Investigation (I.19-06-015) in accordance with D.20-05-019 and System Hardening costs recorded to MWC 08W through December 31, 2020 included in the 2020 Wildfire Mitigation Catastrophic Events Application (A.20-09-019).[1711] PG&E states that recovery of program costs not forecast in this general rate case may be included in future proceedings.[1712] In referring to future proceedings, the Commission assumes PG&E is referring to possible use of CEMA applications and other wildfire-related costs proceedings.

4.24.1. PG&E Request

As explained by PG&E, its forecast for the Community Rebuild Program includes Major Work Categories spanning three lines of business, including Electric Operations (PG&E Ex-04), Gas Operations (PG&E Ex-03), and Customer Care/Meters and AMI Modules (PG&E Ex-06).[1713] PG&E presents its total request for capital and expense from 2018 through 2026 as noted at PG&E Ex-04 at WP Table 23-13.

The total company Community Rebuild Program capital costs PG&E requests are approximately $81 million in 2019, $158 million in 2020, $187.3 million in 2021, $226.4 million in 2022, $203.3 million in 2023, $167.5 million in 2024, and $106.8 million in 2025, and $27 million in 2026.[1714] The scope of this request excludes costs for emergency response activities PG&E

[1711] D.20-05-019, *Decision Approving Proposed Settlement Agreement with Modifications* (May 7, 2020).

[1712] PG&E Ex-04 at 23-28.

[1713] PG&E Ex-04 at 23-2.

[1714] PG&E Ex-04 at 23-2; PG&E Ex-04 at WP Table 23-13.

incurred immediately following the Camp Fire.[1715] PG&E's total company 2023 expense forecast for Community Rebuild is $16.7 million.[1716]

Regarding only Electric Operations (PG&E Ex-04), PG&E's 2023 expense forecast for the Community Rebuild Program is $13.781 million.[1717] PG&E's request for capital expenditures within Electric Operations (PG&E Ex-04) for the Community Rebuild Program is $87.513 million in 2021, $124.132 million in 2022, $116.590 million in 2023, $96.096 million in 2024, $64.367 million in 2025, and $16.940 million in 2026.[1718]

In addition, PG&E proposes to include the recorded and forecast capital costs for 2018 and 2022 (still unrecovered) associated with the Community Rebuild Program in its 2023-2026 capital revenue requirements, stating, "PG&E has proposed to include in its 2023-2026 capital revenue requirements, the recorded and forecast capital costs associated with activities that are being recorded to memorandum accounts [CEMA and WMPMA] through the year 2022."[1719]

[1715] PG&E Ex-04 at 23-1; PG&E Reply Brief at 494 (fn. 2202).

[1716] PG&E Ex-04 at 23-3 (This amount does not include the escalation adjustments set forth in PG&E's Ex-33 September 6, 2022 Update Testimony.)

[1717] PG&E Reply Brief at 494 (PG&E's expense forecast with the escalation adjustment set forth in PG&E Ex-33September 6, 2022 Update Testimony, is $15.548 million); PG&E Ex-04 at 23-4; PG&E Opening Brief at 579-580. PG&E's expense forecast includes the following MWCs: Temporary Services for Pedestal Program, Construction Site Cleaning, Community Rebuild Program Management Office (PMO), Underground Preventative Maintenance and Equipment Repair, and Community Rebuild PMO

[1718] PG&E Reply Brief at 494 (PG&E's Electric Distribution capital forecast does not include the escalation adjustment set forth in PG&E Ex-33 September 6, 2022 Update Testimony); PG&E Opening Brief at 579-580.

[1719] PG&E Ex-23 at 15-3; PG&E Reply Brief at 495.

PG&E also confirms that it will not include the Community Rebuild Program expenses and capital expenditures which the Commission already disallowed from the CEMA recorded costs, according to D.20-05-019.[1720] The Commission agrees that CEMA-related disallowed amounts pursuant to D.20-05-019 must not be included in PG&E's revenue requirement.[1721]

PG&E proposes that PG&E's costs for the Community Rebuild Program forecasted from 2023-2026 should not be subject to CEMA cost recovery because they relate to activities beyond the restoration of service and repair of damaged facilities caused by the 2018 Camp Fire, and PG&E relies on Pub. Util. Code Section 454.9 which addresses the parameters of a Catastrophic Event Memorandum Account.[1722] According to PG&E, its undergrounding work within the Community Rebuild (Town of Paradise and surrounding area) is mostly for wildfire mitigation, "as opposed to the CEMA work of restoring the overhead lines that had been destroyed by the fire."[1723] PG&E requests that this "non-CEMA work" be recoverable in this GRC on a forecast basis, rather than

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[1720] PG&E Opening Brief at 586 (fn. 2499), *citing to* PG&E-14, p. 3-AtchA-1, lines 6-9 (provides the supporting accounting showing the costs PG&E has absorbed to comply with the penalty in D.20-05-019). D.20-05-019, *Decision Approving Proposed Settlement Agreement with Modifications* (May 7, 2020).

[1721] PG&E Opening Brief at 584; PG&E Ex-14 (Rebuttal) at 3-7 ("These disallowed amounts are excluded from PG&E's 2023 GRC RRQ."); PG&E Ex-14 (Rebuttal) at 3-AtchA-1 (page 61/71 of PDF). Chart sets forth 17 specific disallowances for a total of $1.824 billion. Disallowances 1 through 9 reflect the settlement agreement. Disallowances 10 through 17 reflect orders in D.20-05-019.

[1722] PG&E Reply Brief at 495; PG&E Opening Brief at 581. Section 454.9 provides: The commission shall authorize public utilities to establish catastrophic event memorandum accounts and to record in those accounts the costs of the following: (1) Restoring utility services to customers. (2) Repairing, replacing, or restoring damaged utility facilities. (3) Complying with governmental agency orders in connection with events declared disasters by competent state or federal authorities.

[1723] PG&E Reply Brief at 496.

subject to reasonableness review under the CEMA framework.[1724] PG&E states, "At some point, when PG&E performs work in Paradise [after the 2018 Camp Fire], the work is no longer CEMA work. PG&E respectfully submits that once the lines have been restored under CEMA activities, all subsequent activities pertaining to those lines (whether PG&E hardens, undergrounds, or performs some other wildfire mitigation activity on them) properly should not be construed as a CEMA activity."[1725] According to PG&E, a memorandum account is no longer appropriate because PG&E is able to reasonably forecast the costs for 2023 and beyond, stating, "[T]he 2023-2026 costs are not CEMA costs, and they can be accurately forecast."[1726] PG&E likens the scenario here to the one it encountered in 1992 in connection with the Oakland firestorm, where the Commission in D.92-12-016 treated undergrounding as outside appropriate CEMA recovery. In summary, PG&E asserts that the work in and around Paradise is not CEMA work anymore.

4.24.2. Party Positions

Cal Advocates recommends capital expenditures of $0.00 in 2021, 2022, and 2023 because, prior to when the Commission authorizes recovery of these costs, the Commission must conduct a reasonableness review pursuant to Pub. Util. Code Sections 451 and 454.9, as stated in D.20-05-019, and consistent with the law governing CEMA memorandum accounts.[1727] In addition, regarding all costs (recorded and forecasted) associated with the Community Rebuild Program, Cal Advocates states the Commission should direct PG&E to continue

[1724] PG&E Reply Brief at 496-497.

[1725] PG&E Reply Brief at 497.

[1726] PG&E Reply Brief at 500.

[1727] Cal Advocates Opening Brief at 317-319.

to record these costs in a CEMA account with a reasonableness review process and not authorize PG&E to seek recovery in a GRC.[1728] Specifically regarding 2018, 2019, and 2020 capital costs recorded in a CEMA memorandum account, totaling an estimated $155.853 million, Cal Advocates states the Commission should direct PG&E to remove the costs from the results of operations model.[1729] Cal Advocates explains that, by including these CEMA costs in capital in the absence of a reasonableness review, PG&E will earn a rate of return on these costs before the Commission has found these costs reasonable.[1730] Cal Advocates states that its position applies to all costs related to the Community Rebuild Program, which are set forth in PG&E Ex-04, Ch. 23.[1731]

TURN's analysis is framed by the degree of destruction caused by the 2018 Camp Fire and its opinion that PG&E acted unreasonably in connection with its role in the ignition of the fire, stating that "the Camp Fire, a catastrophic wildfire [was] caused due to the utility's failure to operate its utility system in a safe manner, leading to the utility's criminal conviction on 84 counts of involuntary manslaughter and one count of unlawfully causing a fire."[1732] As such, TURN requests the Commission direct PG&E to continue to seek cost recovery under the framework of CEMA accounts and reject PG&E's request to include in revenue requirement its 2023-2026 expense and capital costs for Community Rebuild of approximately $504.6 million and deny PG&E's request to include its capital expenditures, dating back to 2018 and recorded in its CEMA, into the

[1728] Cal Advocates Opening Brief at 317.

[1729] CALPA Ex-05 at 47.

[1730] Cal Advocates Opening Brief at 317.

[1731] Cal Advocates Opening Brief at 317 and 319, *citing to* PG&E Ex-04 at WP Table 23-13.

[1732] TURN Reply Brief at 120-121.

revenue requirement in this proceeding.[1733] TURN states that PG&E has not demonstrated the reasonableness of these costs for rate recovery purposes pursuant to prior Commission decisions and rules governing CEMA accounts.[1734] TURN contends that PG&E's approach would inappropriately and unnecessarily have the Commission review costs of this single rebuilding and restoration effort in a number of proceedings.[1735] TURN states that all rebuilding and restoration costs associated with the 2018 Camp Fire should be reviewed in a CEMA application and rate recovery only permitted after the Commission has determined the extent to which PG&E has demonstrated that such costs are reasonably recovered in rates.[1736] TURN suggests that PG&E should consolidate its requests into as few CEMA applications as possible to avoid fragmentation of the review process.[1737]

Comcast states that PG&E's forecast for the Community Rebuild Program has not sufficiently addressed construction of service drop cables and conduit to connect to residential homes under the Community Rebuild Program.[1738]

4.24.3. Discussion

The Commission is not persuaded by PG&E's position regarding the costs of the Community Rebuild Program related to the 2018 Camp Fire in and around the Town of Paradise and the other costs, such as the Butte Wildfire rebuild,

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[1733] TURN Opening Brief at 585.

[1734] TURN Opening Brief at 585.

[1735] TURN Opening Brief at 585.

[1736] TURN Opening Brief at 498-499.

[1737] TURN Ex-13 at 2-9.

[1738] Comcast Ex-01 at 7.

reflected in PG&E Ex-04 at WP Table 23-13.[1739] Our analysis is influenced by the shocking level of destruction and resulting manslaughter convictions from PG&E's conduct related to the ignition of the 2018 Camp Fire.

In characterizing PG&E's role in the 2018 Camp Fire and other fires, the Commission previously stated in D.20-05-019, as follows:

> There is no question that the physical and economic harm resulting from the 2017 and 2018 wildfires is unprecedented. The 2017 and 2018 wildfires resulted in over 100 deaths, the destruction of over 25,000 structures, and the burning of hundreds of thousands of acres. There is also no dispute that PG&E equipment played a role in igniting the 15 fires for which SED found violations. While PG&E accepts that its equipment played a role in igniting certain fires, PG&E continues to dispute SED's assertions that it violated applicable laws, rules, and regulations.[1740]

Within the context of PG&E's role in the 2018 Camp Fire, the Commission finds that all PG&E's costs related to rebuilding in and around the Town of Paradise to replace the infrastructure destroyed in the 2018 Camp Fire shall be recorded into and subject to a reasonableness review within the CEMA framework under Pub. Util. Code Section 454.9. PG&E acknowledges that a reasonableness review applies prior to 2018-2022 cost recovery but seeks to distinguish these early costs from later costs in 2023-2026, as reflected in PG&E's testimony quoted above. The Commission also denies PG&E's request to seek to

[1739] Note: Certain MWCs and MATs impacted by PG&E's Community Rebuild costs that are set forth in PG&E Ex-04 at WP Table 23-13 are specifically addressed in other Sections. For example, the Commission adopts $0 of capital expenditures at Section 6.6, Gas AMI Module Replacement Project. The Commission determination here to remove the costs is consistent with these other Sections, herein. MAT 14D, as addressed in PG&E-03, Ch. 4 was subject to reductions and the adopt amount is $0.

[1740] D.20-05-019, *Decision Approving Proposed Settlement Agreement with Modifications* (May 7, 2020) at 20-21.

recover costs related to the 2018 Camp Fire within the framework of a GRC on a forecast basis or without a prior reasonableness review. The Commission clarifies that all costs related to the "rebuild" shall be interpreted broadly and consistent with the statute to include restoring, repairing, replacing, and complying with government standards for the infrastructure destroyed in the 2018 Camp Fire and shall be presented to the Commission for a reasonableness review consistent with Pub. Util Code Section 454.9. Moreover, Pub. Util. Code Section 454.9 does not limit the type of costs that the Commission may review in a CEMA account, in the manner suggested by PG&E, to only include costs to replace the exact type and quality of equipment destroyed, and instead specifically refers to a broad range of some of the potential types of costs, as follows:

> (1) Restoring utility services to customers.
>
> (2) Repairing, replacing, or restoring damaged utility facilities.
>
> (3) Complying with governmental agency orders in connection with events declared disasters by competent state or federal authorities.
>
> (b) The costs, including capital costs, recorded in the accounts set forth in subdivision (a) shall be recoverable in rates following a request by the affected utility, a commission finding of their reasonableness, and approval by the commission. The commission shall hold expedited proceedings in response to utility applications to recover costs associated with catastrophic events.[1741]

In terms of PG&E's suggestion that the Commission needs to determine a point in time when a prior reasonableness review under CEMA is no longer applicable for work related to the 2018 Camp Fire, stating that "At some point, when PG&E performs work in Paradise [after the 2018 Camp Fire], the work is

[1741] Pub. Util. Code Section 454.9(a)(1)-(3) and (b).

no longer CEMA work…," it is reasonable to require PG&E to continue to submit costs incurred under its Community Rebuild Program under the CEMA framework under Pub. Util. Code Section 454.9 subject to after-the-fact reasonableness review. We reject PG&E's position that the cost forecasts for the Community Rebuild Program from 2023-2026 should not be subject to CEMA cost recovery because they relate to activities beyond traditional CEMA restoration work, to include undergrounding work that will provide superior and longer-lasting benefits to customers. We also find that the Oakland firestorm case PG&E cites, D.92-12-016, is inapplicable here; while it is true the Commission denied undergrounding costs as part of PG&E's CEMA request, it did so because it found the affected community should pay for the undergrounding under Rule 20, which is not relevant here.

If PG&E has committed to undergrounding assets that were not underground prior to the 2018 Camp Fire in connection with the restoration of service in Paradise, that does not limit the Commission from evaluating the reasonableness of such costs pursuant to Pub. Util. Code Section 454.9. Instead, the Commission expects the costs PG&E incurs in connection with rebuilding the Town of Paradise are reasonable according to current best practices. In response to TURN's recommendation, the Commission does not require a single CEMA application.

Accordingly, the Commission is not persuaded by PG&E's above noted requests pertaining to the rebuilding costs after the 2018 Camp Fire, as reflected in PG&E's Community Rebuild Program (including the Town of Paradise and surrounding area and the Butte Wildfire rebuild) and recorded in PG&E Ex-04 at WP Table 23-13. PG&E may seek recovery of the costs presented in PG&E Ex-04 at WP Table 23-13 in a CEMA application and, as a result, adopt an expense forecast of $0 and capital expenditures of $0 for all the expense and capital presented in this proceeding (2018-2026). The Commission also directs PG&E to submit a table in its prepared testimony (rather than or in addition to its workpapers) in PG&E's next GRC that reflects the same categories of information found in PG&E Ex-04 at WP Table 23-13 with updates to reflect the next rate case period to facilitate the Commission reviewing the Community Rebuild Program in its entirety. In addition, to facilitate transparency in costs and revenue requirement impact of wildfire CEMA-related work, PG&E's Community Rebuild Program is a project that solely refers to the rebuild in the Town of Paradise. Other wildfire-related "rebuild" projects must be separately named, tracked, and presented in table format consistent with PG&E Ex-04 at WP Table 23-13, regardless of how PG&E internally accounts for these costs for purposes of GRCs or records the costs in a CEMA account, in all future GRCs.

4.25. Electric Distribution Ratemaking

4.25.1. Wildfire Mitigation Balancing Account

PG&E seeks to continue the use of the Wildfire Mitigation Balancing Account (WMBA) and some modifications to the framework governing this account, as adopted by the Commission in D.20-12-005.[1742] The Commission authorized the WMBA in D.20-12-005 (PG&E TY 2020 GRC) as a two-way balancing account to track wildfire risk mitigation costs, also referred to as Community Wildfire Safety Program (CWSP) costs, beginning January 1, 2020.[1743]

[1742] PG&E Ex-17 (Rebuttal) at 4-2.

[1743] PG&E Ex-17 (Rebuttal) at 4-2 (fn. 3) *citing to* D.20-12-005 at 396 (COL 29): Authority to establish a two-way WMBA to record CWSP O&M and capital expenditures is supported by the record and should be authorized.

PG&E describes these costs as falling within Electric Distribution, Shared Services, and Human Resources, with the primary costs recorded to the WMBA being wildfire risk mitigation expense and capital expenditures.[1744] PG&E explains that, in addition to the WMBA, it has two other memorandum accounts where certain wildfire-related costs can be recorded, the FRMMA and the WMPMA.[1745] PG&E states that the forecasts for the following costs are tracked in the WMBA: (1) Situational Awareness and Forecasting; (2) PSPS Operations; (3) System Hardening, Enhanced Automation, and PSPS Impact Mitigations; (4) CWSP PMO; (5) Information Technology for Wildfire Mitigation; (6) Enhanced Powerline Safety Settings; (7) Overhead and Underground ED Maintenance; (8) Pole Asset Management; (9) Community Rebuild Program; and (10) Communications.[1746] PG&E's total forecasted amounts for the WMBA in 2023 are approximately $228 million in expense and approximately $1.3 billion in capital for 2023.[1747] PG&E seeks to continue and also increase the "WMBA reasonableness review threshold" for total spending and certain unit costs.[1748] PG&E requests that this threshold, established in the 2020 PG&E GRC, be

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[1744] PG&E Ex-17 (Rebuttal) at 4-2.

[1745] PG&E Ex-04 at 22-26.

[1746] PG&E Ex-04 at Table 4-5, described by PG&E as "The forecast for Wildfire Mitigations tracked in the WMBA are in Section E, Table 4-5."

[1747] PG&E Ex-04 at Table 4-5, described by PG&E as "The forecast for Wildfire Mitigations tracked in the WMBA are in Section E, Table 4-5." In addition to authorizing the WMBA and setting thresholds for the review of costs, D.20-12-005 (PG&E TY 2020 GRC Decision) provides that PG&E cannot earn an equity return on the first $3.21 billion of capital expenditures it spends on wildfire mitigation measures included in its approved WMP. D.20-12-005 at 397 (COL 33). Costs requested in Ch. 4 are in excess of the $3.21 billion as discussed in Exhibit (PG&E-10), Ch. 15, Section D.

[1748] PG&E Ex-17 at 4-3, citing to PG&E Ex-04, stating that the "unit costs for each type of system hardening work are shown in Exhibit (PG&E-4), (Feb. 25, 2022), p. 4.3-51, Table 4.3-11."

increased from 115% to 125%.[1749] PG&E seeks authority to recover above-authorized costs through a Tier 3 advice letter, while the Commission required an application in D.20-12-005.[1750] According to PG&E, a two-way balancing account continues to be the appropriate tool for recording costs for wildfire mitigations given the continued "uncertainty regarding wildfire mitigation costs PG&E ultimately will incur versus what is forecast"[1751] in this proceeding and additionally, stating "A two-way balancing account is the appropriate tool for recording costs for wildfire mitigations given the increasing wildfire risk and the ongoing impacts of climate change because it allows PG&E to adjust its comprehensive wildfire mitigation strategy as needed to keep our customers and communities safe."[1752]

TURN opposes PG&E's request and suggests that, under PG&E's proposed balancing account treatment, PG&E will essentially be able to recover from ratepayers an amount in excess of the Commission-authorized forecast without any demonstration that the above-authorized amounts were consistent with forecasted spending or reasonably incurred.[1753] TURN recommends that the Commission modify the WMBA by removing the "reasonableness threshold" and changing the WMBA to a one-way balancing account set at the amount of the forecast adopted by the Commission (no increased percent threshold), with a companion memorandum account for recording any above-authorized

[1749] PG&E Ex-17 at 4-3.

[1750] PG&E Ex-04 at 4-23.

[1751] PG&E Opening Brief at C-3 and C-4.

[1752] PG&E Opening Brief at 585.

[1753] TURN Reply Brief at 136-137.

spending.[1754] TURN supports its recommendation by stating, "On a forward-looking basis, PG&E should be able to forecast wildfire mitigation costs for the WMBA …at a sufficient level of accuracy and confidence that the protection of a two-way balancing account is no longer needed."[1755]

Cal Advocates supports PG&E's request to continue the WMBA as a two-way balancing account at a "reasonableness review threshold of 115%" but recommends the Commission deny PG&E's request to modify the WMBA to raise the reasonableness threshold to 125%.[1756] Cal Advocates states that PG&E's modifications fail to "provide protection for ratepayers against possible overspending."[1757] Cal Advocates suggests that, because this is the first time PG&E has included many of its WMBA activities in a GRC, insufficient historical data exists to support any increase.[1758]

The Commission finds insufficient evidence of "uncertainty" to continue the WMBA in its current format, as authorized in D.20-12-005. In 2020, when the Commission authorized the WMBA, the Commission determined that sufficient uncertainty existed in new costs related to wildfire mitigation and implementation of PG&E's Wildfire Mitigation Plan to warrant such an account, but now PG&E indicates that the most significant costs tracked in the WMBA, System Hardening - undergrounding, are projected to decline during the rate case period. The Commission finds that PG&E's projected declining costs for wildfire mitigation in PG&E Ex-04 are not consistent with the purpose of the

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[1754] TURN Opening Brief at 507-508.

[1755] TURN Opening Brief at 507-508.

[1756] Cal Advocates Opening Brief at 320.

[1757] Cal Advocates Opening Brief at 320.

[1758] Cal Advocates Opening Brief at 306.

current structure of the balancing account. Accordingly, the Commission finds it reasonable to continue the WMBA for this rate case period (2023-2026) as a one-way balancing account, with the 115% reasonableness threshold eliminated. PG&E may seek continuation of the WMBA in its 2027 GRC if PG&E considers the continuation of the WMBA useful beyond 2026.

4.25.2. Vegetation Management Balancing Account

PG&E also seeks authorization to continue the two-way Vegetation Management Balancing Account (VMBA) for this rate case period (2023-2026), which the Commission continued in D.20-12-005 (PG&E TY 2020 GRC) and, in addition, to continue the account as a two-way account with an increased reasonableness review threshold of 125%.[1759] The Commission in D.20-12-005 also authorized PG&E to record both enhanced vegetation management and routine vegetation management in the VMBA.[1760] PG&E requests the Commission authorize PG&E to seek recovery of amounts up to 125% through a Tier 2 Advice Letter due to continuing uncertainties about Vegetation Management costs due to external factors.[1761]

TURN recommends the Commission revise the VMBA to return it to being a one-way balancing account. TURN recommends that if the Commission believes PG&E should have an opportunity to recover above-authorized spending, it should create a companion Vegetation Management Memorandum

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[1759] D.20-12-005 at 412, stating that the current threshold is 120%, and at 395, explaining, "The settlement proposes to modify PG&E's current one-way VMBA that records routine VM expenses into a two-way balancing account that will record both routine and enhanced VM spending. Originally, costs for enhanced VM were proposed to be recorded in the WMBA. First, we agree with tracking both routine and enhanced VM costs into a single balancing account."

[1760] D.20-12-005 at 77-78.

[1761] PG&E Opening Brief at 589.

Account as the mechanism for recording above-authorized spending, subject to later review in a reasonableness review application. TURN opposes PG&E's request to increase the reasonableness threshold to 125% but suggests the Commission could adopt a treatment of above-authorized spending similar to that adopted for PG&E's AMI program, with 90% of up to 6% of the authorized amount deemed reasonable and recovered in rates without any after-the-fact reasonableness review and remaining amounts.[1762]

Cal Advocates does not oppose PG&E's request to increase the recovery threshold of its two-way VMBA to 125% given the uncertainty of potential changes to PG&E's vegetation management program scope and unforeseen impacts related to regulation, external commitments, customer input, weather, and climate.[1763]

Cal Advocates does not contest PG&E's proposal regarding the VMBA because the increase in the reasonableness review threshold is "slight" and "given the uncertainty in PG&E's Vegetation Management Program forecasts based on scope and unforeseen impacts related to regulation, external commitments, customer input, weather, and climate change."[1764]

The Commission finds that PG&E has failed to provide persuasive evidence that continuation of the VMBA as a two-way balancing account with an increased reasonableness review threshold of 125% is reasonable. In reviewing the framework of the VMBA in 2020, the Commission previously found evidence to support a two-way balancing account with a reasonableness review threshold, stating, "[T]he enhanced VM program is new and so a proper forecast that

[1762] TURN Opening Brief at 510-511.

[1763] Cal Advocates Opening Brief at 306-307.

[1764] Cal Advocates Opening Brief at 321-322.

balances both affordability and necessary work that needs to be performed is difficult to determine. In addition, the scope of activities continues to be refined…."[1765] PG&E is now well-experienced at an increased level of vegetation management, including Enhanced Vegetation Management plus its routine vegetation management. PG&E has been implementing increased vegetation management as a wildfire mitigation since at least 2018. Accordingly, the Commission finds that continuation of the VMBA is appropriate to account for remaining external uncertainties, but a one-way balancing account is sufficient and a reasonableness review threshold is no longer appropriate because PG&E's forecasts rely upon at least 4-5 years of data and PG&E has reached a higher level of sophistication, generally, regarding vegetation management within the context of climate change.

5. Energy Supply

PG&E's requested forecasts for Energy Supply expense and capital expenditures are set forth in PG&E Ex-05 and related documents. PG&E's Energy Supply activities are performed by the following two departments: (1) the Generation Department, and (2) the Energy Policy and Procurement Department.[1766]

The Generation Department performs the following three organizational functions: (1) Nuclear Operations (Diablo Canyon Power Plant); (2) Hydro Operations; and (3) Natural Gas and Solar Operations.[1767] The Energy Policy and Procurement Department is responsible for planning, management, and

[1765] D.20-12-005 at 78.

[1766] PG&E Ex-05 at 1-1.

[1767] PG&E Opening Brief at 594.

administration of PG&E's electric and natural gas portfolios.[1768] PG&E also has an organizational function within Energy Supply referred to as Business Technology, which supports the operational processes related to the generation of electricity and procurement of electric and gas supply.[1769]

PG&E's forecast for expense and capital expenditures to support Energy Supply is summarized below.[1770]

- Expense forecast in 2023 is $590.4 million (2020 recorded adjusted expenditure is $607 million).
- Capital expenditure requests are $267.3 million in 2021, $261.3 million in 2022, $397.7 million in 2023, $377.2 million in 2024, $328.3 million in 2025, and $282.3 million in 2026. The recorded adjusted capital expenditure for 2020 is $282.8 million.[1771]

The capital projects proposed during this rate case period are for generation equipment, dams, and waterways, safety and regulatory projects, and infrastructure. PG&E made minor revisions to its request for capital expenditures on July 11, 2022 in PG&E Ex-18 (Rebuttal).

5.1. PG&E Request

PG&E states that its forecast of expense and capital expenditures for Energy Supply are set forth in the table below and includes the following:

- The cost of operating and maintaining Diablo Canyon Power Plant, 64 hydroelectric powerhouses, three natural gas generation facilities, and 13 solar photovoltaic facilities, including capital for necessary investment in these facilities;

[1768] PG&E Opening Brief at 617.

[1769] PG&E Ex-05 at 7-1.

[1770] PG&E Ex-05 at 1-5.

[1771] PG&E Ex-05 at 1-9.

- Administrative costs for managing PG&E's Energy Supply portfolio;
- Costs associated with re-licensing PG&E's hydro facilities and complying with new or amended licenses;
- Decommissioning costs of PG&E's hydro, natural gas, and solar generation facilities; and
- Costs to acquire, upgrade, and enhance information technology systems that support the Energy Supply departments.

In addition to the cost forecasts presented for Energy Supply, PG&E also seeks approval of certain ratemaking proposals related to Energy Supply, which are discussed below.

Table 5-A: [1772]
PG&E's 2023 Energy Supply Expense Forecast By Department (Millions Of Nominal Dollars)[(a)]

Organizations	2023
Nuclear Operations (Diablo Canyon Power Plant)	$313.6
Hydro Operations	$177.9
Natural Gas and Solar	$52.3
Energy Policy and Procurement	$43.8
Business Technology	$2.8
Energy Supply Total	$590.4

(a) PG&E-05 at 1-5, Table 1-1 as adjusted by PG&E-18 at 6-3, Table 6-1, line 5.

Table 5-B: [1773]
PG&E's Energy Supply Capital Forecast By Department (Millions Of Nominal Dollars)[(a)]

Organizations	2020 Rec.	2021	2022	2023	2024	2025	2026
Nuclear Operations (Diablo Canyon Power	$49.6	$22.0	$13.0	$11.0	$6.0	$1.0	$-

[1772] PG&E Opening Brief at 594.

[1773] PG&E Opening Brief at 595.

Organizations	2020 Rec.	2021	2022	2023	2024	2025	2026
Plant)							
Hydro Operations	$197.9	$223.0	$227.9	$366.3	$348.1	$303.9	$261.4
Natural Gas and Solar	$16.0	$10.0	$5.4	$6.3	$9.2	$9.7	$7.4
Energy Policy and Procurement	$-	$-	$-	$-	$-	$-	$-
Business Technology	$19.3	$12.3	$15.0	$14.1	$13.9	$13.7	$13.5
Energy Supply Total	$282.8	$267.3	$261.3	$397.7	$377.2	$328.3	$282.3

(a) PG&E-05 at 1-9, Table 1-2 as adjusted by PG&E-18 at 5-4, Table 5-3, line 9.

5.2. Party Positions and Stipulations

TURN, Cal Advocates, and jointly by California Trout, Inc., Friends of the Eel River, and Trout Unlimited Trout contest aspects of PG&E's forecast for Energy Supply. PG&E entered into separate stipulations with each of these parties to resolve all contested issues regarding Energy Supply. These stipulations are described below.

On August 18, 2022, PG&E's stipulation with Cal Advocates and California Trout, Inc., Friends of the Eel River, and Trout Unlimited was entered into the record as PG&E Ex-30.[1774] This stipulation resolved disputes regarding various forecasts for the component of PG&E's Energy Supply expense forecast referred to as Hydro Operations.

On November 1, 2022, after the conclusion of evidentiary hearings, TURN and PG&E reached a stipulation resolving all contested issues between the two parties related to Energy Supply, except for those related issues not addressed in PG&E Ex-05, including escalation rates, attrition year adjustments,

[1774] PG&E Ex-30 August 18, 2022 Stipulation Among The Public Advocates Office At The California Public Utilities Commission (Cal Advocates), California Trout, Inc., Friends Of The Eel River, Trout Unlimited And Pacific Gas And Electric Company.

and depreciation.[1775] This stipulation is referred to as the November 1, 2022 TURN-PG&E Energy Supply Stipulation and is found at Appendix E of PG&E's Opening Brief. For purposes of determining final forecasts, PG&E and TURN agree that the escalation amounts adopted by the Commission in this decision should apply to forecasts amounts in the November 1, 2022 TURN-PG&E Energy Supply Stipulation.

On November 21, 2022, after Opening Briefs were submitted, PG&E and Cal Advocates reached a stipulation resolving all contested issues between the two parties related to PG&E's Energy Supply forecast.[1776] This stipulation is referred to as the Cal Advocates-PG&E Energy Supply Stipulation found at Appendix B of PG&E's Reply Brief filed on December 9, 2022.

No party contests these three stipulations. The terms of these stipulations are addressed below within in the context of PG&E's requests in PG&E-05 Energy Supply.

5.3. Energy Supply – Expense

5.3.1. Energy Policy and Procurement

PG&E's 2023 expense forecast for Energy Policy and Procurement, as reflected in PG&E's rebuttal testimony is $43.786 million, an increase of $3.130 million over 2020 recorded costs.[1777] PG&E states the primary driver for the increase in the 2023 forecast is five additional staff members to support implementation of PG&E's biomethane program.[1778] This increase is reflected in

[1775] PG&E Opening Brief, Appendix E at E-1 (Stipulation of TURN and PG&E on Energy Supply Issues).

[1776] PG&E Reply Brief, Appendix B at B-1 to B-2.

[1777] PG&E Opening Brief at 617-618.

[1778] PG&E Reply Brief at 510.

the costs tracked in MWC CV Acquire and Manage Gas Supply. Cal Advocates proposed a reduction of $918,000 to PG&E's request on the basis that it was unreasonable for PG&E to hire five additional staff to support the biomethane program because, according to Cal Advocates, the legislation establishing the program does not envision additional staffing.[1779]

In response, PG&E agreed to modify its expense request to eliminate the cost of additional staff but noted that the correct reduction for this modification to the 2023 expense forecast is less than noted by Cal Advocates and should be $685,000. After applying this reduction to its 2023 expense forecast for MWC CV Acquire and Manage Gas Supply, PG&E presents a lower expense forecast of $2.445 million.[1780] PG&E's November 21, 2022 stipulation with Cal Advocates resolves the disputes regarding PG&E's expense forecast for activities related to acquiring and managing gas supply tracked in MWC CV Acquire and Manage Gas Supply and provides for the lower 2023 expense forecast for MWC CV Acquire and Manage Gas Supply within Energy Procurement Administrative of $2.445 million.

This topic is similarly addressed and resolved in the TURN-PG&E Energy Supply Stipulation.

As a result of these two stipulations, PG&E has agreed to a reduced 2023 expense forecast for Energy Supply of $575.2 million.[1781] PG&E's request was $590.4 million (, as shown above. The Commission finds reasonable these aspects of the Cal Advocates-PG&E Energy Supply Stipulation and the TURN-PG&E Energy Supply Stipulation, which reduce PG&E's request by

[1779] Cal Advocates Opening Brief at 317.

[1780] Cal Advocates Opening Brief at 317. PG&E Reply Brief at 510.

[1781] PG&E Reply Brief at 510.

$685,000 based on reduced staffing. Accordingly, the Commission adopts a $685,000 reduction to the 2023 forecasted expense for MWC CV Acquire and Manage Gas Supply Energy Supply.

5.3.2. Hydro Operations Expense

PG&E's Hydro Operations expense forecast covers the direct operations and maintenance expenses for 64 hydro powerhouses and supports facilities, as well as the operational management and support services.[1782] In PG&E's June 30, 2021 Application, PG&E presented a 2023 expense forecast for Hydro Operations of $177.909 million.[1783] PG&E stated that the primary drivers of the increase over the 2020 recorded expense of $158.297 million were escalation, regulatory compliance, increase in costs to maintain hydro infrastructure, decrease in costs to operate hydro assets, and decrease in other hydro costs.[1784] This includes work reflected in 16 Major Work Categories.[1785]

In response, TURN proposed a reduction of $35.1 million to PG&E's Hydro Operations 2023 expense forecast of $177.909 million based on the following proposals: (1) use of a four-year average (2016-2019) as the basis for the forecast; (2) use of a 10-year average (2010-2020) as the basis for headcount assumptions; (3) use of the forecasts for Large Uncontrolled Water Release projects presented in PG&E's 2020 RAMP Report; (4) removal of the cost to comply with license conditions for projects with pending FERC relicensing applications; and (5) transfer of projects out of the Hydro Licensing Balancing Account or HLBA that are not required by a FERC license. Cal Advocates

[1782] PG&E Ex-05 at 4-1 to 4-2.

[1783] PG&E Opening Brief at 600.

[1784] PG&E Ex-05 at 4-1 to 4-2.

[1785] PG&E Ex-05 at 4-1 to 4-2.

proposed a reduction of $3.5 million to PG&E's 2023 expense forecast of $177.909 million based on the following proposals: (1) removal of the cost of six additional hires to support ISO 55000 certification; and (2) removal of the costs related to the Recreation Point Campground project.

PG&E and TURN stipulated to a reduction in the 2023 Hydro Operations expense forecast of $6.0 million, which includes a reduction of $4.7 million for setting Large Uncontrolled Water Release risk costs equal to those presented in PG&E's 2020 RAMP and a reduction of $1.3 million in response to TURN's and Cal Advocates' headcount reduction recommendations. As a result, the parties stipulated to a 2023 expense forecast for Hydro Operations of $171.9 million. PG&E's stipulations with TURN and Cal Advocates resolve the disputed issues between these parties regarding the 2023 Hydro Operations expense forecasts.[1786]

The Commission finds the stipulated 2023 expense forecast for Hydro Operations of $171.9 million to be reasonable and adopts it. The Commission addresses the contested issues regarding the Hydro Licensing Balancing Account below.

5.3.3. Natural Gas and Solar Expense

PG&E's Natural Gas and Solar expense forecast covers the direct operations and maintenance expenses for its natural gas generation facilities and the solar stations. PG&E's 2023 expense forecast of $52.258 million is undisputed.[1787] TURN stipulated to PG&E's 2023 Natural Gas and Solar forecast as a part of the TURN-PG&E Energy Supply Stipulation.[1788] The Commission finds this aspect of the stipulation reasonable. Accordingly, the Commission

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[1786] PG&E Reply Brief at 509.

[1787] PG&E Opening Brief at 613.

[1788] PG&E Opening Brief, Appendix E at E-2.

adopts a 2023 forecast for Natural Gas and Solar within Energy Supply of $52.258 million.

5.3.4. Nuclear Operations Expense

PG&E's cost forecasts related to the Diablo Canyon Power Plant are presented as part of PG&E's Energy Supply forecast and referred to as Nuclear Operations. PG&E's expense forecast is a reduction from existing funding levels and reflects the costs to operate the Diablo Canyon Power Plant until expiration of the current operating licenses in 2024 and 2025.[1789] For ratemaking purposes, PG&E's decommissioning costs are accounted for, recovered, and reviewed in a separate proceeding, the Nuclear Decommissioning Cost Triennial proceeding (also referred as the NCDTP).[1790]

Notably, on September 2, 2022, while this proceeding was pending, Senate Bill 846 extended the possible operation of the Diablo Canyon Power Plant beyond the expiration dates of the current operating licenses and up to five additional years under specified conditions.[1791] Subsequently, the Nuclear Regulatory Commission allowed PG&E to update its previously filed license

[1789] PG&E Opening Brief at 596; PG&E Reply Brief at 508.

[1790] The Commission's current proceeding regarding PG&E NCDTP and Diablo Canyon Power Plant is A.21-12-007. In the NDCTP, the Commission forecasts PG&E's decommissioning costs and reviews the reasonableness of decommissioning expenses. This proceeding remains open and there are few (if any) decommissioning expenses at this time but a balance of approximately $3.6 billion remains in the trust funds for any future decommissioning and closure. More information regarding this proceeding is available on the Commission's website at the following link: (https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/decommissioning).

[1791] Senate Bill 846 (Stats. 2022, Ch. 239) authorized, under specified conditions, the extension of operating the Diablo Canyon Power Plant beyond the current expiration dates of 2024 for Unit 1 and 2025 for Unit 2, to up to five additional years (no later than 2029 and 2030, respectively).

renewal application for the Diablo Canyon Power Plant.[1792] The capital and expense forecasts for Diablo Canyon Power Plant presented in this rate case proceeding do not take into account any possible changes in the operational status of the plant contemplated by Senate Bill 846.[1793] Rather, as stated above, the forecasts in this proceeding reflect the shutdown dates of November 2024 (Unit 1) and August 2025 (Unit 2). In addition, the Nuclear Decommissioning Cost Triennial proceeding remains the forum in which the Commission reviews Diablo Canyon Power Plant decommissioning costs. Pursuant to Senate Bill 846, the cost of extending operations beyond the expiration of the current operating licenses for Diablo Canyon Power Plant will be considered in a new proceeding structured similarly to PG&E's annual Energy Resource Recovery Account (ERRA) forecast proceeding with subsequent annual advice letter true-ups to actual costs and market revenues from prior calendar years.[1794] Pursuant to Senate Bill 846, any costs recovered in this new Diablo Canyon Power

[1792] The Nuclear Regulatory Commission's letter allowing PG&E to update its previous license renewal application and submit a sufficient license renewal application for Diablo Canyon Power Plant Units 1 and 2, by December 31, 2023, and, if it does so, receive timely renewal protection under 10 CFR 2.109(b) is available at the following link: https://www.nrc.gov/docs/ML2302/ML23026A109.pdf.

[1793] Senate Bill 846 provides that the Commission not consider any nuclear cost recovery from ratepayers beyond those costs proposed by PG&E in this proceeding, per Pub. Util. Code Section 712.8(d), which provides as follows: "The commission shall not increase cost recovery from ratepayers for operations and maintenance expenses incurred by the operator during the period from August 1, 2022, to November 2, 2025, for Diablo Canyon Power Plant Unit 1 and from August 1, 2022, to August 26, 2025, for Diablo Canyon Power Plant Unit 2, above the amounts approved in the most recent general rate case for the operator pursuant to commission proceeding A.21-06-021 (June 30, 2021) Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2023."

[1794] Senate Bill 846, Pub. Util. Code Section 712.8(h)(1).

Plant-specific cost recovery proceeding will be considered operating expenses not eligible for inclusion in PG&E's rate base.[1795]

The Commission is currently considering next steps toward initiating this new Diablo Canyon Power Plant-specific cost recovery proceeding in R.23-01-007,[1796] which is the successor proceeding to A.16-08-006, the proceeding that addressed the potential continued operations of Diablo Canyon Power Plant per Senate Bill 846.[1797] On December 1, 2022, the Commission issued D.22-12-005 to preserve the option of extended operations beyond the expiration of the current licenses at Diablo Canyon Power Plant, including the tracking of costs in balancing and memorandum accounts to ensure proper recording and recovery of the costs associated with the plant's continued operation and, as stated above, Commission will review of those costs in R.23-01-007 or a successor Diablo Canyon Power Plant-specific cost recovery proceeding.[1798]

For these reasons, the Commission continues to consider PG&E's forecast based on decommissioning in this proceeding. PG&E requests that the Commission adopt its 2023 Nuclear Operations expense forecast of $313.6 million.[1799] PG&E's 2020 expense was $357.230 million.[1800] PG&E states that the primary drivers for its reduced forecasted expense from 2020-2023 are

[1795] Senate Bill 846, Pub. Util. Code Section 712.8(h)(1).

[1796] R.23-01-007, Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations (January 12, 2023).

[1797] A.16-08-006, Application of Pacific Gas and Electric Company for Approval of the Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms (U39E) (filed August 11, 2016).

[1798] PG&E Reply Brief at 507–509.

[1799] PG&E Ex-05 at 3-1 to 3-2.

[1800] PG&E Ex-05 at 3-1 (Table 3-1).

escalation, changes in support cost allocations, changes in outage work scope and duration, employee attrition, security overtime costs, and other cost changes.[1801] The Nuclear Operations expense forecast includes work tracked in 11 Major Work Categories.[1802] PG&E also requests to continue several ratemaking proposals regarding Nuclear Operations, included in the Nuclear Regulatory Commission Regulatory Balancing Account.[1803] These ratemaking proposals are addressed at Section 5.5, below.

In response, TURN recommends a reduction of $21.540 million across the costs tracked in nine different Major Work Categories, which reflects TURN's position that PG&E accurately calculates labor forecasts.[1804] TURN's recommendations for Nuclear Operations expense is $291.108 million.[1805] As part of the stipulation, TURN and PG&E resolve the contested issues pertaining to PG&E's expense forecast for Nuclear Operations and agree to a reduction of $9.2 million to PG&E's 2023 forecast of $313.6 million, resulting in a recommended Nuclear Operations expense forecast for 2023 of $304.4 million.[1806]

The Commission finds this aspect of the stipulation reasonable and adopts a Nuclear Operations 2023 expense forecast within Energy Supply of $304.4 million.

[1801] PG&E Opening Brief at 596.

[1802] PG&E Opening Brief at 597.

[1803] PG&E Ex-05 at 3-1.

[1804] PG&E Opening Brief at 597.

[1805] PG&E's forecasts for costs tracked in MWC AK Manage Environmental Operations and MWC EO Provide Nuclear Support are uncontested.

[1806] PG&E Opening Brief at 596-597 and Appendix E at E-1.

5.4. Energy Supply – Capital Expenditure

5.4.1. Natural Gas and Solar Capital Expenditures

PG&E presents a Natural Gas and Solar capital expenditures request of $10.033 million in 2021, $5.370 million in 2022, $6.336 million in 2023, $9.181 million in 2024, $9.734 million in 2025, and $7.386 million in 2026.[1807] PG&E's capital forecast is tracked in five Major Work Categories, four of which are undisputed.[1808] The one disputed capital expenditure forecast is for costs tracked in MWC 2S. PG&E's forecast for MWC 2S was $3.640 million in 2023, $7.929 million in 2024, $8.568 million in 2025, and $6.196 million in 2026.[1809] TURN recommends reductions of $3.235 million in 2023, $2.347 million in 2024, $2.854 million in 2025, and $4.447 million in 2026 to reflect a 16% reduction to PG&E's capital forecasts for the Humboldt Bay Generation Station replacement engine emissions modules and to eliminate PG&E's forecast for emergent work.[1810]

PG&E requests authority to adjust, on a prospective basis, the schedule for amortization of Long-Term Service Agreement (LTSA) milestone payments when PG&E's natural gas plants are operated more than expected so that PG&E can true-up its recovery of milestone payments in the next GRC. TURN recommended that both upward and downward adjustments in the amortization of the milestone payments should occur consistent with the actual performance of the combined cycle units.[1811] PG&E agreed with TURN's recommendation and

[1807] PG&E Opening Brief at 613.

[1808] PG&E Opening Brief at 613.

[1809] PG&E Opening Brief at 613-614.

[1810] PG&E Opening Brief at 613-614.

[1811] PG&E Opening Brief at 616-617.

made this cost adjustment to its forecast in rebuttal testimony.[1812] The TURN-PG&E Energy Supply Stipulation adopts this adjustment by PG&E.

The TURN-PG&E Energy Supply Stipulation adopts TURN's proposal to reduce the Humboldt Bay Generation Station replacement engine emissions module costs by 16% resulting in the following reduction: $0.235 million in 2023, $0.347 million in 2024, $0.354 million in 2025, and $0.361 million for 2026.[1813] The TURN-PG&E Energy Supply Stipulation also presents a 50% reduction to the emergent work capital expenditure forecast in MWC 2S resulting in the following reduction: $0 million in 2023, $2.0 million in 2024, $2.5 million in 2025, and $4.1 million in 2026.[1814] Based on these agreements, TURN and PG&E propose a forecast of $3.405 million in 2023, $5.582 million in 2024, $5.714 million in 2025, and $1.735 million in 2026 for costs tracked in MWC 2S and a total Fossil/Solar capital expenditure forecast of $6.100 million 2023, $6.834 million 2024, $6.879 million in 205, and $2.925 million in 2026.[1815]

TURN and PG&E also stipulate to the removal of the cost forecast for the Gateway Evaporative Cooling Project.[1816]

The Commission finds these aspects of the TURN-PG&E Energy Supply Stipulation reasonable and adopts the reduced stipulated capital expenditure forecasts for Natural Gas and Solar Generation within Energy Supply for 2023-2026.

[1812] PG&E Opening Brief at 616-617.

[1813] PG&E Opening Brief at 613-614.

[1814] PG&E Opening Brief at 614.

[1815] PG&E Opening Brief at 614.

[1816] PG&E Opening Brief at 615.

5.4.2. Nuclear Operations Capital Expenditures

PG&E's forecast for the Diablo Canyon Power Plant capital expenditures is $22 million for 2021, $13 million for 2022, $11.0 million for 2023, $6.0 million for 2024, $1.0 million for 2025, and $0 for 2026.[1817] PG&E's 2020 recorded cost is $49.6 million.[1818] PG&E states its decreasing trend in the capital expenditure forecast reflects the Commission's directive on January 11, 2018 in D.18-01-022, *Decision Approving Retirement of Diablo Canyon Nuclear Power Plant* requiring PG&E to re-examine required expenditures in light of the then-expected shutdown in 2025.

TURN contests several aspects of PG&E's capital forecast, including the need for the Diablo Canyon Power Plant Aging Management program, and also proposes a disallowance of the Unit 2 Polisher Computer workstation project. In addition, TURN recommends that 50% of the costs for two other proposed capital projects be collected through the Decommissioning Trust funds. In total, TURN recommends reductions to PG&E's request for capital expenditures for Nuclear Operations of $4.201 million in 2023, $4.954 million in 2024, and $0.998 million in 2025.[1819]

The parties address this dispute in the November 1, 2022 TURN-PG&E Energy Supply Stipulation. TURN stipulates to PG&E's forecast for Nuclear Operations capital expenditures of $22 million for 2021, $13 million for 2022, $11.0 million for 2023, $6.0 million for 2024, $1.0 million for 2025, and $0 for 2026 in exchange for PG&E's agreement that it will only request the

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[1817] PG&E Ex-05 at 1-9.

[1818] PG&E Ex-05 at 1-9.

[1819] TURN Ex-14 at 7 (Table 3).

Commission-authorized forecasts in this proceeding that are recorded and recovered through the Diablo Canyon Retirement Balancing Account.[1820]

The Commission finds the outcome regarding a reduced capital expenditures forecast reasonable because it addresses TURN's concern that costs recorded to the Diablo Canyon Retirement Balancing Account are not subject to reasonableness review while the stipulated amount also presents sufficient capital for the safe and reliable operation of Diablo Canyon Power Plant through the expiration of the current operating licenses. Accordingly, the Commission adopts the stipulated amounts for Nuclear Operations capital expenditure of $11.0 million for 2023, $6.0 million for 2024, $1.0 million for 2025, and $0 for 2026.

5.5. Ratemaking Proposals

PG&E request approval of several proposals for the ratemaking associated with Energy Supply.

5.5.1. Diablo Canyon Retirement Balancing Account

The Diablo Canyon Retirement Balancing Account is a two-way balancing account established to implement the approved ratemaking associated with the retirement of Diablo Canyon Power Plant, including recovery of the plant's Net Book Value.[1821] The difference in revenue requirements between the rate case-approved capital expenditures and the actual capital additions are tracked in the Diablo Canyon Retirement Balancing Account.[1822]

PG&E and TURN stipulate to continuing the Diablo Canyon Retirement Balancing Account and that capital expenditures of $11.0 million for 2023,

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[1820] PG&E Opening Brief at 598.

[1821] PG&E Opening Brief at 631.

[1822] PG&E Opening Brief at 631.

$6.0 million for 2024, $1.0 million for 2025, and $0 million for 2026 be tracked in this balancing account.[1823] The parties to the stipulation further agree that any recorded capital above the agreed upon capital expenditures for Nuclear Operation of $18 million (2023-2026) will not be recorded to the Diablo Canyon Retirement Balancing Account and PG&E will not seek recovery in rates.[1824]

The Commission finds this aspect of the stipulation reasonable and adopts it with the limitation that amounts exceeding $18 million will not be recorded to the Diablo Canyon Retirement Balancing Account and not be recoverable in rates.

5.5.2. Nuclear Regulatory Commission Regulatory Balancing Account

PG&E requests that the Commission approve its proposal to continue a previously approved balancing account, the Nuclear Regulatory Commission Regulatory Balancing Account.[1825] The balancing account is a two-way balancing account for expense costs related to implementation of Nuclear Regulatory Commission requirements.[1826] The Commission authorized the Nuclear

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[1823] PG&E Opening Brief at E-1.

[1824] In D.18-01-022, the Commission approved the shutdown (recently modified by Senate Bill 846) of Diablo Canyon Power Plant, created a subaccount in the Diablo Canyon Retirement Balancing Account to help true-up the depreciation rates for plant and capital additions approved in general rate cases that would still be needed even though Diablo Canyon Power Plant was closing. The amortization period for plant/capital additions was set to the remaining life of DCPP. The Diablo Canyon Retirement Balancing Account subaccount tracks the difference in revenue requirements between general rate case-approved capital additions and the actual capital additions, which is annually transferred to the Portfolio Allocation Balancing Account on January 1st for recovery.

[1825] PG&E Ex-05 at 3-2.

[1826] PG&E Ex-05 at 8-1.

Regulatory Commission Regulatory Balancing Account in D.18-01-022.[1827] For the period 2023-2025, PG&E forecasts approximately $7.1 million in expense associated with regulatory requirements that would be tracked and recovered through this balancing account.[1828] PG&E no longer uses the balancing account for capital.[1829] PG&E intends to continue the account for tracking expense, as approved in D.18-01-022, and requests a modification to the terms of this account.[1830] The modification requested by PG&E is that, at the end of the operation of the Diablo Canyon Power Plant, PG&E seeks authority to file a Tier 1 Advice Letter to transfer the final balance in the Nuclear Regulatory Commission Regulatory Balancing Account to the Portfolio Allocation Balancing Account and close the Nuclear Regulatory Commission Regulatory Balancing Account.[1831] PG&E made this request based its plan to decommission the Diablo Canyon Power Plant.[1832] Since PG&E now may continue the Diablo Canyon Power Plant's operation, this request to close the Nuclear Regulatory Commission Regulatory Balancing Account is denied.

5.5.3. Hydro Licensing Balancing Account

PG&E requests to continue the use of the balancing account referred to as the Hydro Licensing Balancing Account. The Hydro Licensing Balancing

[1827] PG&E Ex-05 at 3-2, stating that the Nuclear Regulatory Commission Regulatory Balancing Account was first approved by the Commission in PG&E's 2014 general rate case decision, *citing to* D.14-08-032 at 420 and at 736.

[1828] PG&E Ex-05 at 8-7.

[1829] PG&E Ex-05 at 3-2. PG&E Ex-05 at 8-6, stating the Diablo Canyon Retirement Balancing Account will be in place to address any regulatory-related capital costs that might otherwise be eligible for recording in the Nuclear Regulatory Commission Regulatory Balancing Account.

[1830] PG&E Ex-05 at 1-11.

[1831] PG&E Ex-05 at 3-2.

[1832] PG&E Opening Brief, Appendix B, at B-8, item 18.

Account is a two-way balancing account authorized by the Commission to manage the capital and expense forecasts related to FERC hydro licensing activities.[1833] PG&E also requests authority to expand the terms of the Hydro Licensing Balancing Account to include costs related to the settlement agreements associated with certain FERC hydro licenses, regardless of the date of license issuance.[1834]

TURN contests PG&E's request on the basis that PG&E is proposing a significant increase in capital expenditures and expense spending with recovery through the Hydro Licensing Balancing Account, and TURN is concerned that the Hydro Licensing Balancing Account has been overcollected in prior years. TURN also states that the absence of reasonableness reviews for completed capital projects is problematic.[1835] For these reasons, TURN proposes to change the Hydro Licensing Balancing Account to a one-way balancing account to track project spending that exceeds the original forecast and require PG&E to seek cost recovery in a subsequent GRC.[1836]

PG&E and TURN resolved this dispute in the TURN-PG&E Energy Supply Stipulation with, among other things, the following stipulations: (1) maintain the Hydro Licensing Balancing Account as a two-way balancing account, (2) PG&E will withdraw its proposal to include pre-2012 license condition settlement amounts in the Hydro Licensing Balancing Account, (3) PG&E agrees to provide refunds to customers if the actual combined capital and expense revenue

[1833] PG&E Opening Brief at 622.

[1834] PG&E Ex-05 at 1-11. This work addresses the Crane Valley Recreation Settlement Agreement and the 2017 Oroville Dam Incident.

[1835] TURN Opening Brief at 526.

[1836] TURN Opening Brief at 526; PG&E Opening Brief at 622; PG&E Ex-05 at 8-2.

requirements over each two-year period is less than authorized, (4) TURN agrees to not contest rate recovery by PG&E if combined capital and expense revenue requirements over each two-year period exceeds the authorized revenue by 20% or less, (5) parties agree to a Tier 3 Advice Letter for reasonableness review of combined capital and expense revenue requirements over each two-year period if they exceed authorized by more than 20%, and (6) PG&E withdraws its proposal for creations of the Helms Capacity Memorandum Account.[1837]

The Commission finds this proposal reasonable regarding maintaining the Hydro Licensing Balancing Account, as described above. The Commission considers the Helms Capacity Memorandum Account below.

5.5.4. Helms Capacity Memorandum Account

PG&E proposes a new memorandum account, the Helms Capacity Memorandum Account, effective January 1, 2023 to track the costs of a capacity uprate at the Helms Pumped Storage Facility.[1838] In support of its request, PG&E states that this capacity uprate project is being undertaken in response to a Commission-identified need for incremental long duration storage and that, at the time of preparing its rate case request, the project was at the very early stages of development.[1839] As a result of this project being in such an early stage of development, PG&E explains that the project's expense and capital expenditures are not forecast in this proceeding.[1840] TURN opposed PG&E's proposal due to the absence of cost information in this proceeding.[1841]

[1837] TURN Opening Brief at Appendix A, Section IV.

[1838] PG&E Ex-05 at 1-11.

[1839] PG&E Ex-05 at 1-11.

[1840] PG&E Ex-05 at 1-11.

[1841] TURN Opening Brief at 528.

In the TURN-PG&E Energy Supply Stipulation, PG&E agrees to withdraw its request to create the Helms Capacity Memorandum Account while TURN agrees to allow PG&E to seek cost recovery for the Helms Uprate Project if those costs are found reasonable, the project is cost-effective, and PG&E has sought project approval in a future proceeding.[1842]

The Commission finds the stipulation to withdraw PG&E's request to create the Helms Capacity Memorandum Account reasonable.

5.5.5. Utility-Owned Generation Vintaging

In this proceeding, PG&E did not include any recommendations regarding the vintages assigned to PG&E's Utility-Owned Generation (UOG) for purposes of calculating the Power Charge Indifference Adjustment (PCIA) because, as stated by PG&E, it does not propose any changes to the vintaging or the current framework for assigning cost responsibility to bundled and unbundled customers for UOG.[1843] PG&E states that it supports continuation of the current approach that was directed by the Commission in D.18-10-019.[1844] According to PG&E, the current approach ensures that customers pay for the costs of investments made on their behalf, including the costs of decommissioning a resource.[1845]

The Joint CCAs make several ratemaking recommendations related to changing how the useful lives of generating assets are defined and costs allocated, such as vintage assignments.[1846] Specifically, the Joint CCAs state that

[1842] PG&E Opening Brief at 624; TURN Opening Brief at Appendix A, Section IV.

[1843] PG&E Opening Brief at 624-625.

[1844] PG&E Opening Brief at 624-625.

[1845] PG&E Opening Brief at 624-625.

[1846] Joint CCAs Opening Brief at 47.

12 hydro resources whose useful life is extended in PG&E's depreciation study should be re-vintaged, such that customers who depart prior to the new vintage year would no longer be responsible for those resources' cost in the Power Charge Indifference Adjustment. The Joint CCAs further propose a framework for determining whether resources should be re-vintaged by default in the future and urge the Commission to require PG&E to file specific testimony to inform vintaging decisions in its future GRC applications. The Joint CCAs state that these recommendations are intended to change the so-called vintaging framework to provide a more consistent and equitable approach to PG&E's utility owned generation vintaging policy.[1847]

PG&E opposes the recommendations of the Joint CCAs, stating that D.18-10-019 in the PCIA rulemaking, R.17-06-026, does not require re-vintaging in these circumstances and that "extending the life of a legacy UOG asset…should never result in re-vintaging that asset."[1848] PG&E also raises the concern that re-vintaging these assets for PCIA purposes would allow departed customers to avoid paying for eventual decommissioning costs.

While the Joint CCAs are correct that the Commission found in D.18-10-019 that in general these fact-specific vintaging considerations should be addressed in the relevant GRC, without sufficient record to address this aspect of the Joint CCAs' proposal, the Commission cannot approve this specific re-vintaging requests for the assets in question here. The parties have raised a number of issues — such as whether departed customers should continue to share in the costs of legacy UOG resources in perpetuity — that bear further

[1847] Joint CCAs Opening Brief at 47.

[1848] PG&E Reply Brief at 514

consideration. The Joint CCAs may propose a specific approach for re-vintaging the 12 hydro resources that addresses whether and how to ensure departed customers pay a share of decommissioning those resources in another proceeding, such as A.23-05-012, PG&E's 2024 Energy Resource and Recovery Account (ERRA) application or PG&E's 2025 ERRA application. With respect to Joint CCAs' framework proposal, the Commission also declines to consider it in this proceeding, as this would require a thorough examination of the complexities involving the current vintaging framework and how costs are allocated as part of the PCIA.[1849] This review would best take place in a broader proceeding in which other utilities and stakeholder positions may be considered.[1850] Finally, the Commission find reasonable the Joint CCAs' request for PG&E to provide specific information about its resources in future GRCs, as this information will be helpful to our consideration of proposed changes to assets regardless of whether any broader framework is adopted. Accordingly PG&E is directed to include in its future GRC filings its position and any supporting evidence concerning (1) the details of any PG&E proposal for new asset life extensions, incremental capacity additions, or changed functions for any of its UOG assets and why it is undertaking these changes, (2) on whose behalf it is making these new investments, and (3) the appropriate vintaging treatment for each asset in light of this testimony along with any future GRC proposals.[1851]

[1849] PG&E Opening Brief at 624-631.

[1850] October 1, 2021 Assigned Commissioner's Scoping Memo and Ruling at 3-5.

[1851] R.17-06-026, Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the Power Charge Indifference Adjustment (June 29, 2017).

5.5.6. Hydro Decommissioning Accrual

PG&E states that the intent of a hydro decommissioning reserve is to accrue decommissioning funds while the plant is used and useful; therefore the annual accrual calculation is generally based on the forecast retirement dates rather than the earliest decommissioning start year.[1852] PG&E proposes recovery of an annual accrual of $62.2 million for the hydro decommissioning reserve.[1853]

No parties object to continuing the hydro decommissioning accrual. However, Cal Advocates originally proposed reducing PG&E's $62.2 million annual accrual request to $23.9 million due to objections over the Battle Creek project. Additionally, California Trout, Friends of The Eel River, and Trout Unlimited proposed changes to the probability factor for the Potter Valley decommissioning estimate that would have increased total decommissioning costs by between $40 million to $62 million.[1854]

PG&E, Cal Advocates, California Trout, Inc., Friends of The Eel River, and Trout Unlimited entered into a stipulation that supports a $48 million annual hydro decommissioning accrual for the rate case period of 2023-2026. This stipulation is marked as PG&E Ex-30.[1855] This stipulation was not contested.

The Commission finds that these aspects of the uncontested stipulation between PG&E-Cal Advocates, California Trout, Inc., Friends of The Eel River, and Trout Unlimited reasonable and adopts the forecasts and stipulations therein.

[1852] PG&E Opening Brief at 620.

[1853] PG&E Opening Brief at 621.

[1854] PG&E Opening Brief at 621.

[1855] PG&E Reply Brief at 511; PG&E Opening Brief at 620-621. The stipulation was marked as an PG&E Ex-30 and entered into the record.

5.6. Adoption of Stipulations

After reviewing the three uncontested stipulations, the Commission finds that the TURN-PG&E Energy Supply Stipulation, the Cal Advocates-PG&E Energy Supply Stipulation, and PG&E-Cal Advocates-California Trout, Inc., Friends of the Eel River, and Trout Unlimited Stipulation are reasonable. No other parties contested Energy Supply issues. It is clear from the record and from the stipulations that TURN and Cal Advocates had a comprehensive understanding of the issues and facts, and the capacity to engage in the stipulation process. Therefore, the Commission finds the stipulations reasonable and adopts these stipulations as presented.

5.7. Uncontested Costs

Unless otherwise provided for in the stipulated costs during this rate case period (2023-2026), PG&E's uncontested 2023 expense forecast and uncontested 2021, 2022 and 2023 capital expenditure requests as set forth in PG&E Ex-05 Energy Supply, are found reasonable.[1856]

6. Customer and Communications

6.1. Overview

PG&E presents its forecast for Customer and Communications expense and capital expenditures in PG&E Ex-06.[1857] PG&E states that its forecast for Customer and Communications supports customer strategy and communications across all lines of business and the delivery of a range of services, products, and support "to the approximately 16 million people in

[1856] The uncontested expense and capital expenditure forecasts for Energy Supply are set forth in Appendix A to PG&E's Opening Brief at A-13 and A-24.

[1857] PG&E Opening Brief at 632.

PG&E's service territory."[1858] PG&E requests a forecast for Customer and Communications as follows:[1859]

- TY 2023 expense forecast is $386.680 million ($225 million is uncontested) with a 2020 recorded adjusted amount of $312.983 million; and
- Capital expenditures is $171.597 million (recorded adjusted) for 2020 and a request of $226.012 million in 2021, $277.221 million in 2022, $338.811 million in 2023, $379.387 million in 2024, $326.279 million in 2025, and $298.061 million in 2026.

PG&E's Customer and Communications expense and capital forecast is organized into the following: (1) Regional Vice Presidents; (2) Customer Engagement; (3) Customer Service Offices; (4) Compliance and Regulatory Strategy; (5) Gas Advanced Metering Infrastructure (AMI) Module Replacement; (6) Customer Care Technology Projects; (7) Pricing Products and Income Qualified Programs; (8) Contact Centers, Customer Technology and Digital Strategy; (9) Billing, Revenue and Credit; (10) Metering Services and Engineering; and (11) Communications.[1860] The disputed forecasts are addressed below.

6.2. Regional Vice Presidents – Regionalization

PG&E states that Customer and Communications includes a program referred to as Regional VPs and their teams (herein Regional VPs).[1861] PG&E's

[1858] PG&E Opening Brief at 632.

[1859] PG&E Opening Brief at 632-633.

[1860] PG&E Ex-06 at 1-9.

[1861] PG&E Ex-06 at 1A-1.

Regional VPs are embedded in the regions for which they are responsible.[1862] PG&E hired the five Regional Vice President positions as part of a regionalization effort the Commission ordered in connection with PG&E's bankruptcy in D.20-05-053 and for which the Commission later approved a settlement in D.22-06-028 (A.20-06-011).[1863] The Commission stated in D.20-05-053 that the regional restructuring would bring PG&E's management closer to its customers.[1864]

PG&E requests a 2023 expense forecast for Regional VPs of $6.064 million.[1865] PG&E presents an expense of $2.015 million in 2021 and $4.171 million in 2022.[1866] The 2021 expense is the six-month total labor cost for two Executive Assistants and 20 Regional Support Staff with a start date of July 1, 2021.[1867] The 2022 expense is the annual labor cost for two Executive Assistants and 20 Regional Support Staff.[1868] PG&E's 2023 request includes expense (labor

[1862] D.22-06-028, Decision Approving a Multi-Party Settlement Agreement in Part and a South San Joaquin Irrigation District Settlement Agreement in Totality (June 23. 2022), citing to D.20-05-053 at 112; PG&E Ex-06 at 1A-5, fn. 9, stating the "[F]ive regions include North Coast, North Valley and Sierra, Bay Area, South Bay and Central Coast, and Central Valley; A.20-06-011, [Application of Pacific Gas and Electric Company for Approval of Regionalization Proposal. (U39M)] PG&E's Updated Regionalization Proposal (February 26, 2021), Attachment A, p. 32."

[1863] D.22-06-028, Decision Approving a Multi-Party Settlement Agreement in Part and a South San Joaquin Irrigation District Settlement Agreement in Totality (June 23, 2022), citing to D.20-05-053 at 112.

[1864] D.22-06-028, Decision Approving a Multi-Party Settlement Agreement in Part and a South San Joaquin Irrigation District Settlement Agreement in Totality (June 23, 2022) at 45.

[1865] PG&E Ex-06 at 1A-2.

[1866] PG&E Ex-06 at 1A-8; PG&E Opening Brief at 633 states that for Regional VPs also includes cost for (but addressed separately) Customer and Communications Operation Management of approximately $6.118 million.

[1867] PG&E Ex-06 at WP 1A-3.

[1868] PG&E Ex-06 at WP 1A-3.

and non-labor) and no capital expenditures.[1869] PG&E's 2023 expense forecast includes work tracked in MWC OM, Operational Management, which includes expense for the five Regional Vice President positions, two Executive Assistants, and 20 Regional Support Staff, approximately 27 positions.[1870] PG&E tracks additional regionalization implementation costs in the Regional Plan Memorandum Accounts RPMA-E and RPMA-G, which were authorized effective June 30, 2020,[1871] but does not seek recovery of all of the costs (e.g., Program Management Office human resources and information technology) from the RPMA-E or RPMA-G in this GRC. PG&E states that it engaged five Regional Vice Presidents in 2021 and shareholders funded these positions through 2022.[1872] PG&E requests that the Regional Vice President positions be funded by ratepayers starting January 1, 2023 and going forward.[1873] PG&E states it could not have requested compensation for the Regional Vice President positions in its 2020 GRC because those positions did not exist when PG&E filed its 2020 GRC application in December 2018.[1874] PG&E states that although it voluntarily did not seek officer compensation in the 2020 GRC, PG&E did not waive its right to recover officer compensation in future GRCs.[1875] PG&E states the Commission held in Southern California Edison's (SCE) 2021 GRC that SCE could recover the costs of compensation for utility officers who are not defined by Rule 240.3b-7 of

[1869] PG&E Ex-06 at 1A-2.

[1870] PG&E Ex-06 at 1A-6; PG&E Opening Brief at 633.

[1871] TURN Ex-600 at 10.

[1872] PG&E Ex-06 at 1A-6.

[1873] PG&E Ex-06 at 1A-6.

[1874] PG&E Ex-19 (Rebuttal) at 1A-4.

[1875] PG&E Ex-19 (Rebuttal) at 1A-4.

the Securities Exchange Act and that the Regional Vice President positions are not designated as Section 240.3b-7 officers.[1876]

TURN disputes PG&E's expense forecast for the Regional Vice President positions in MWC OM and recommends removing $1.747 million from the 2023 expense forecast.[1877] TURN contends that PG&E fails to support its request for this $1.747 million for the following reasons: (1) PG&E has not provided a forecast for improvements in safety performance as a result of additional spending requested in this GRC; (2) PG&E has not proposed any accountability mechanisms for whether or not PG&E's safety performance would improve as a result of the additional spending; and (3) PG&E fails to adequately justify changing the current funding source from shareholders to ratepayers.[1878]

In response, PG&E argues that TURN is relitigating issues raised, considered and rejected by the Commission in D.20-05-053, which approved PG&E's Regionalization Plan.[1879]

In D.22-06-028, the Commission authorized a settlement pertaining to PG&E's regionalization plan and explained that, when the Commission approved PG&E's plan to emerge from bankruptcy in D.20-05-052, the Commission stated as follows regarding regionalization: "PG&E shall take steps so that by one year from the date of this decision it will be able to appoint

[1876] PG&E Ex-19 (Rebuttal) at 1A-4 to 1A-5.

[1877] TURN Opening Brief at 530.

[1878] TURN Opening Brief at 529-530; TURN Reply Brief at 140-141.

[1879] TURN Opening Brief at 530-532; PG&E Reply Brief at 522; D.22-06-028, Decision Approving a Multi-Party Settlement Agreement in Part and a South San Joaquin Irrigation District Settlement Agreement in Totality (June 23, 2022): D.20-05-053 at 52.

regional executive officers to manage each region and report directly to the CEO…."[1880]

As described in D.22-06-028, the Commission directed PG&E in D.20-05-053 to implement regional restructuring and appoint regional executive officers to manage each region. The Commission did not explicitly approve the Regional Vice President positions in either D.20-05-052 or D.22-06-028. The Commission also noted that metrics must be developed and reported to the Regionalization Stakeholder Group, including but not limited to the Safety Performance Metrics and Safety and Operational Metrics adopted in R.20-07-013, by the conclusion of Phase II of the implementation schedule for the regionalization plan. In addition, the Regional Vice Presidents will establish public goals, metrics, and priorities for their respective regions based on stakeholder input.[1881] In addition, as PG&E confirms, it did not have approval to include the cost of Regional Vice Presidents during the last GRC period.

In D.22-06-028, the Commission found that the estimated costs of regionalization implementation would be between $24.6 million and $32.6 million.[1882] These estimated costs are enumerated in Attachment B of PG&E's July 9, 2021 summary of its updated regionalization proposal, specifically $8.6 million annually for Human Resources labor cost, between $16 million and $24 million for Information Technology, and zero for Real Estate.[1883] The $6.064 million requested in this GRC for the Regional Vice

[1880] D.22-06-028 at 4.

[1881] D.22-06-028 at 13, Attachment A, Multi-Party Settlement Agreement: PG&E's Application for Approval of Regionalization Proposal Application 20-06-011 at 2.

[1882] D.22-06-028 at 30 (Findings of Fact 6).

[1883] PG&E's Summary of the Updated Regionalization Proposal filed July 9, 2021, in A.20-06-011 at Attachment B.

Presidents and their support staff aligns with the cost estimates identified in D.22-06-028. If PG&E requests recovery of any additional regionalization implementation costs tracked in the Regional Plan Memorandum Accounts RPMA-E or RPMA-G, the requests will be subject to reasonableness review by the Commission.[1884]

In this proceeding, the Commission finds PG&E provided sufficient evidence to support its forecasted cost of the salaries for the Regional Vice President positions but remains concerned about excessive spending on staffing for regionalization, consistent with the concerns stated by TURN. Accordingly, the Commission adopts an expense forecast for PG&E's Regional VPs (MWC OM) for 2023 of $6.064 million and also directs PG&E to provide additional cost information to support its request in PG&E's next GRC in 2027 for staffing expense, including, Regional Vice Presidents, their Executive Assistants, their Regional Support Staff, and the Regionalization Program Management Office. This information must include recorded and forecasted costs (expense and capital) for all Major Work Categories (and related subcategories of MAT Codes) that track all costs for PG&E's regionalization efforts, including staffing salaries and benefits, information technology costs, real estate costs, and any other miscellaneous costs associated with regionalization. PG&E shall consolidate all information relating to regionalization costs in one chart in its 2027 GRC and include an explanation of where all the entries in the chart are discussed throughout PG&E exhibits. In addition, PG&E shall report in the 2027 GRC on the safety performance improvements that have occurred because of regionalization, including the performance improvements of individual

[1884] D.22-06-028, Decision Approving a Multi-Party Settlement Agreement in Part and a South San Joaquin Irrigation District Settlement Agreement in Totality (June 23, 2022) at 33.

enterprise-level safety metrics tracked at a regional level and the performance improvements of individual region-specific safety metrics. Finally, PG&E shall compare the actual costs of regionalization implementation, including ongoing human resource costs, to PG&E's estimates of costs for regionalization implementation that PG&E presented in A.20-06-011.

6.3. Customer Engagement

PG&E's Customer Engagement supports a variety of program areas including, for example, services to small and medium businesses, Public Safety Power Shutoff planning and readiness, economic development, resources to support customers who have or are interested in distributed generation, and clean energy transportation.[1885] Customer Engagement also provides essential services and benefits to PG&E's customers through direct customer service and programs.[1886]

PG&E's expense forecast for 2023 is $101.830 million, which is an increase of $23.1 million over the 2020 recorded adjusted of $78.701 million.[1887] PG&E's capital expenditures are $39.161 million (2020 actual recorded) and requests $20.500 million forecast (2021), $2.300 million forecast (2022), $8.550 million forecast (2023); $9.360 million forecast (2024), $4.650 million forecast (2025), and $5.900 million forecast (2026).[1888] Customer Engagement supports the following six program areas: Customer and Community Services, PSPS Planning and Preparedness, Economic Development, Non-Tariffed Products and Services, Distributed Generation and Customer Data Tools, and Clean Energy

[1885] PG&E Ex-06 at 1-2.

[1886] PG&E Opening Brief at 635.

[1887] PG&E Ex-06 at 1-3 and 2-3.

[1888] PG&E Ex-06 at 1-7.

Transportation.[1889] PG&E's increased capital forecast for 2023, 2024, 2025, and 2026 is largely driven by the Internal Fleet Electrification Vehicle Program.[1890]

Cal Advocates and TURN dispute PG&E's expense and capital forecasts associated with the following three programs within Customer Engagement: (1) Non-Tariffed Products and Services; (2) PG&E's Electric Vehicle Infrastructure Program; and (3) Internal Fleet Electrification Program (Internal Fleet Program). These disputed forecasts are discussed below.[1891]

6.3.1. Non-Tariffed Products and Services (MWC EL)

PG&E requests an expense forecast for 2023 of $49.851 million for the New Revenue Development Department's provision of Non-Tariffed Products and Services (also referred to as NTP&S).[1892] No capital expenditure costs are requested.[1893] PG&E's forecasted revenues are an important component of this non-regulated service. PG&E forecasts revenues in 2023 of $60.5 million.[1894]

PG&E explains that it offers its Non-Tariffed Products and Services consistent with the Affiliate Transaction Rules, Rule VII, adopted by the Commission in D.06-12-029.[1895] PG&E states that its Non-Tariffed Products and Services program "primarily" uses underutilized PG&E assets or capacity, such as distribution poles, to generate incremental revenues by marketing products and services to third parties (e.g., the short-term use of PG&E facilities or real

[1889] PG&E Ex-06 at 1-10.

[1890] PG&E Ex-06 at 2-3.

[1891] PG&E Opening Brief at 636.

[1892] PG&E Ex-06 at 2-25.

[1893] PG&E Ex-06 at 2-5.

[1894] PG&E Ex-19 (Rebuttal) at 2-7.

[1895] PG&E Ex-06 at 2-17, fn. 32, *citing to* D.06-12-029, Appendix A-1 at 22, Sec. VII.C.4.a.

property).[1896] According to PG&E's program documentation, typical transactions under this program include joint use pole attachment arrangements, short-term use of conference facilities by third-parties, and customer emergency transform loans.[1897]

PG&E states that the New Revenue Development Department's actual recorded expense for the offering of Non-Tariffed Products and Services in 2019 was $40.8 million and in 2020 was $41.0 million.[1898] PG&E states that its 2023 request for forecasted expense represents an increase in the expense forecast of approximately $8.8 million per year (over 2020 recorded) and will be used to fund expenses related to PG&E's Non-Tariffed Products and Services program.

While this program consists solely of non-regulated services, PG&E seeks authorization to incorporate this forecasted expense, totaling approximately $200 million during the four-year rate case period, into its 2023-2026 revenue requirement and collect this amount from ratepayers in a variety of manners, including from both CPUC- jurisdictional electric rates and gas rates.[1899] PG&E explains that it also allocates forecasted expense for this program to its transmission revenue requirement governed under federal law.[1900]

For this rate case, PG&E incorporates its request for forecasted expense for Non-Tariffed Products and Services activities within the broader category of Customer Engagement, which includes the programs noted above, such as Clean

[1896] PG&E Ex-06 at 2-17.

[1897] PG&E Ex-19 (Rebuttal) at Ch. 2, Attachment A (Twenty-Fifth Periodic Report on Non-Tariffed Products and Services offered by Pacific Gas and Electric Company dated August 31, 2021.)

[1898] PG&E Ex-19 (Rebuttal) at 2-6.

[1899] PG&E Ex-06 at 2-17.

[1900] PG&E Ex-06 at 2-17.

Energy Transportation and PSPS Planning and Preparedness. Importantly, in contrast to these other programs, Non-Tariffed Products and Services is not a regulated utility service. As such, the Commission evaluates this category of costs and the program under a different framework, primarily under the Commission's Affiliate Transaction Rules, adopted in a series of decisions, including D.97-12-088 and D.98-08-035.

In support of its request for increased expenses, PG&E explains that the increase represents an additional $8.8 million for 2023 relative to 2020 recorded costs and is primarily attributable to $7.3 million forecasted for increased demand for Non-Tariffed Products and Services, such as the Utility Energy Services Contract and Sustainable Solutions Turnkey programs, and a forecasted $1.5 million increase in labor, presumably employee costs, to support increased demand for Non-Tariffed Products and Services, plus escalation.[1901]

In support of PG&E's $60.5 million in forecasted revenue for this program in 2023, PG&E explains that its Non-Tariffed Products and Services' expenses are offset by Other Operating Revenues generated from Non-Tariffed Products and Services and credited back to customers. PG&E provides documentation of revenues in recent years and shows that ratepayers received approximately $10 million in 2020 over the expenses covered by ratepayers.[1902] Regarding 2023, PG&E's forecasted revenues of $60.5 million are broken down by PG&E, and PG&E claims such revenues "directly offset... MWC EL's 2023 expense forecast of $49.851 million" and include "$5.9 million of proceeds from the SBA

[1901] PG&E Ex-06 at 2-12.

[1902] PG&E Ex-19 (Rebuttal) at Ch. 2, Attachment A (Twenty-Fifth Periodic Report on Non-Tariffed Products and Services offered by Pacific Gas and Electric Company dated August 31, 2021.)

Communication Corporation (SBA) wireless towers transaction."[1903] PG&E explains that the revenue consisting of the $5.9 million proceeds from SBA Communications Corporation is related to a transaction to sell PG&E's license agreements for more than 700 electric transmission towers and other structures in exchange for an "up-front lump sum" and that PG&E will "return to CPUC customers" the ratepayers' "jurisdictional share" of the "net transaction proceeds" equaling $135.5 million over 20 years, which equals $5.9 million in 2023 and additional amounts each year thereafter.[1904] With the exception of this SBA Communications Corporation transaction with "net transaction proceeds" of $135.5 million to be distributed to ratepayers over the next 20 years, PG&E provides a "forecast" of profits based on past profits but does not provide evidence in the form of specific business transactions or executed contracts to support its forecast of actual profits during the rate case period on a forward- looking basis.

PG&E presents minimal information about the utility assets relied upon and other financial aspects of its Non-Tariffed Products and Services but states that its request of $49.851 million supports "PG&E's efforts to offer additional services [non-utility services] with existing assets [utility assets] to generate revenue, which reduces the costs of service in customer rates."[1905] Further details, such as how PG&E implements a reduction "in cost of service in customer rates," are not provided. Most of the information provided about profits and expense is found in PG&E's *Twenty-Fifth Periodic Report on Non-Tariffed Products and Services*,

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[1903] PG&E Ex-19 (Rebuttal) at 2-7.

[1904] PG&E Ex-10 at 16-6 to 16-7.

[1905] PG&E Ex-06 at 2-25.

dated August 31, 2021.[1906] In that report, PG&E shows costs and allocated profits for 2020 but a number of aspects of the program are unclear, for example, the amount of profits allocated to shareholders.

In addressing the use of utility employees for this program, PG&E explains that it currently offers its Non-Tariffed Products and Services program through its New Revenue Development Department (expenses are tracked in MWC EL).[1907] According to PG&E, the New Revenue Development employee team works on a variety of projects that are either funded through a GRC (CPUC-jurisdictional rates) or the federal transmission rate case.[1908] PG&E provides few details regarding how the expense of such employees, including benefits, is allocated to shareholders or FERC-jurisdictional ratepayers for collection in PG&E's rates, which becomes critical when evaluating PG&E's request to collect approximately $200 million (2023-2026) in California utility rates. The amount of overall financial support provided by shareholders (who share in the profits), such as employee expenses, is particularly difficult to discern from the information provided by PG&E, even though PG&E initially justified this program in 1999 by claiming that "shareholders would receive half of the gains in exchange for bearing the risk associated with incremental investments necessary to provide the product or service."[1909]

Cal Advocates and TURN dispute PG&E's forecasted expense for this program. They recommend a reduced forecast for 2023 on the basis that PG&E

[1906] PG&E Ex-19 (Rebuttal) at Ch. 2, Attachment A.

[1907] PG&E Ex-06 at 2-25.

[1908] PG&E Ex-06 at 2-17.

[1909] D.99-04-021, In the Matter of the Application of Pacific Gas and Electric Company for the Authority to Adopt a Revenue-Sharing Mechanism and Other Prerequisites for New Non-Tariffed Products and Services (April 1, 1999), 1999 Cal. PUC LEXIS 228 at *11.

has not substantiated its claim of an increased demand for Non-Tariffed Products & Services.[1910] Cal Advocates recommends a lower forecast of $40.3 million based on average actual expense for three years, 2018-2020, and TURN recommends a lower forecast of $41.013 million based on PG&E's 2020 recorded expense.[1911] In response, PG&E disputes TURN's assertion that PG&E is asking ratepayers to pay $8.8 million (the increase over 2020 recorded) in order to receive $20 million less in revenues. TURN clarifies its position: "TURN's argument was that the overall revenues from NTP&S is forecasted to decrease significantly, and therefore an increase in expenses is unreasonable."[1912] TURN also states: "TURN is recommending that the level of expense be maintained at the current level even though revenues are expected to decrease by more than $20 million a year. In contrast, PG&E is asking ratepayers to pay $8.8 million more in order to receive $20 million less. That is a bad outcome that would lead to unjust and unreasonable rates and should be rejected by the Commission."[1913] PG&E does not offer further support for its forecast for 2023 when refuting TURN's illustrative calculations showing an unexplained inequity.[1914]

In reviewing PG&E's request, the Commission notes that, approximately 20 years ago, PG&E explained to the Commission that the Non-Tariffed Products & Services program benefits ratepayers because revenue from third-party transactions offsets associated Non-Tariffed Products & Services

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[1910] Cal Advocates Opening Brief at 636.

[1911] Cal Advocates Opening Brief at 326.

[1912] TURN Reply Brief at 141.

[1913] TURN Reply Brief at 141.

[1914] PG&E Opening Brief at 636-638.

program expenses (e.g., invoicing, contract administration, etc.) and the net revenue in excess of expenses is shared 50/50 with the shareholders.[1915] As explained by PG&E, ratepayers receive half of the net revenue from NTP&S in exchange for the use of regulated utility assets.[1916] In 1999, the Commission summarized PG&E's sharing mechanism as follows: "PG&E proposes a more direct approach for a sharing of the revenues…Ratepayers and shareholders would each receive half of any revenues remaining after deducting all reasonable expenses related to the provision of new non-tariffed offerings, including corporate taxes. Shareholders would bear any losses resulting if these net revenues are negative."[1917] In 1999, the Commission authorized this sharing mechanism on a temporary basis. The amount of ratepayer funds at issue in 1999 was presumably much smaller than $100 million. Later, in 2011, the Commission modified this 50/50 sharing mechanism and rejected that element of the settlement in D.11-05-018 and adopted a "cost of service" approach for accounting.[1918] The Commission provided guidance to PG&E regarding the program, stating:

> While it is our preference that this process of exploitation of economies be performed by the utility's unregulated affiliates, under the purview of our Affiliate Transactions Rules, company management may find this approach impractical and decide, instead, to utilize our NTP&S program. If so, we need to be ensured that this program will not divert utility expertise and other resources enough to affect utility service, will not distort existing non-utility markets, and reasonably

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[1915] D.99-04-021, 1999 Cal. PUC LEXIS 228 at *5.

[1916] D.99-04-021, 1999 Cal. PUC LEXIS 228.

[1917] D.99-04-021, 1999 Cal. PUC LEXIS 228 at *5-*6.

[1918]D.11-05-018, Decision on Pacific Gas and Electric Company Test Year 2011 General Rate Increase Request (May 5, 2011) at 22-23.

reimburse ratepayers for the use of their assets for the project.[1919]

In this proceeding, PG&E requests authorization to collect approximately $200 million from ratepayers to cover forecasted expenses for a program that provides non-regulated services using utility assets and employees but provides few details on reliable revenue streams for ratepayers during the rate case period, how shareholders (and ratepayers) bear the risk of potential losses, and how it implements a profit-sharing mechanism with shareholders. As such, based on the information provided by PG&E, it is unclear how this program aligns with the Commission's Affiliate Transaction Rules. As presented by PG&E, profits to ratepayers existed in the program in terms of financial gain (amounting to approximately $10 million) in recent years, as shown in PG&E's most recent program Annual Period Report, referenced above.

For these reasons, the Commission finds that PG&E has not supported the expense forecast for New Revenue Development Department Non-Tariffed Products & Services (MWC EL) consistent with the Commission's framework for evaluating these services in D.99-04-021 and D.11-05-018.[1920] The Commission finds that TURN's and Cal Advocates' use of PG&E's historical averages and 2020 actual expense to establish forecasted expense is more reasonable than PG&E's 2023 proposed expense of $49.851 million, and PG&E has not provided sufficient evidence to justify continued financial support of the program by ratepayers for this entire rate case period. The Commission finds that, while short-term continuation of the program funded by ratepayers is reasonable,

[1919]D.11-05-018, Decision on Pacific Gas and Electric Company Test Year 2011 General Rate Increase Request (May 5, 2011) at 23.

[1920] D.99-04-021, 1999 Cal. PUC LEXIS 228 at *16; D.11-05-018, Decision on Pacific Gas and Electric Company Test Year 2011 General Rate Increase Request (May 5, 2011) at 23-24.

longer-term continuation of this program, with funding by ratepayers, requires further information and consideration by the Commission. In addition, based on the absence of detail provided by PG&E, the Commission finds that an independent audit is needed to fully explore the mechanics of PG&E's program.

Accordingly, the Commission adopts a shorter-term expense forecast for New Revenue Development Department Non-Tariffed Products & Services (MWC EL) for two years of this rate case period, equaling $40 million in 2023 and $40 million in 2024, an amount consistent with TURN's recommendation and with PG&E's recorded expense for 2020. PG&E may continue to expand these services under a shareholder-funded arrangement. Furthermore, based on the failure of PG&E to provide persuasive evidence that this program will generate profits on a longer-term basis, the Commission declines in this proceeding to require ratepayers to fund this program in 2025 and 2026. As such, the Commission adopts forecasted expense for 2025 and 2026 of $0 for New Revenue Development Department Non-Tariffed Products & Services (MWC EL). PG&E may continue to offer these services under a shareholder-funded arrangement, as explained further below.

Regarding the 2023 and 2024 ratepayer forecasted expense of $40 million each year, consistent with past practice, the Commission expects PG&E to fully reimburse ratepayers for this $40 million and any additional amount in expense incurred by ratepayers in 2023 and 2024 and ensure ratepayers experience no negative financial impact. Regarding any profits beyond reimbursing ratepayers for the forecasted expense of $40 million, PG&E is directed to retain all profits in an interest-bearing account and not distribute these profits to ratepayers or shareholders until authorized by the Commission.

Additionally, based on PG&E's failure to address basic components of its program, including (1) sufficient detail on the financial benefits to ratepayers, (2) how shareholders (or ratepayers) bear risks of potential loss, (3) information about its profit-sharing mechanism between ratepayers and shareholder, and (4) how the program aligns with the Commission's Affiliate Transaction Rules, the Commission finds that PG&E shall seek authorization from the Commission through a separate application proceeding before reinitiating Non-Tariffed Products & Services as a ratepayer-funded activity beyond the two years authorized herein.[1921] Shareholder funded activities are not restricted. The Commission directs PG&E to file an application justifying continuation of this program on or before March 31, 2024, if PG&E seeks to continue the program with ratepayer expense funding. Any application filed by PG&E shall, at a minimum, include information to address the above-reference program components: (1) details on the benefits to ratepayers, (2) how shareholders (or ratepayers) bear risks of potential loss, (3) information about its profit-sharing mechanism, and (4) how the program aligns with the Commission's Affiliate Transaction Rules. In addition, PG&E shall provide a detailed accounting of for New Revenue Development Department Non-Tariffed Products & Services (MWC EL), expenses, revenues, specific references to assets used (employees and capital assets), values of those assets, costs associated with employee benefits, and allocation between state and federal jurisdictional rates. The application shall specifically address profit amounts and interest rate on those amounts retained in an interest-bearing account and the amounts reimbursed to ratepayers to cover the forecasted annual expense of $40 million. In this

[1921] D.11-05-018; Decision on Pacific Gas and Electric Company Test Year 2011 General Rate Increase Request (May 5, 2011) at 23-24.

application proceeding, the Commission may revisit the type of information included in PG&E Periodic Reports on Non-Tariffed Products and Services. In addition, PG&E is directed to include in its application a copy of the following report previously required by the Commission in D.99-04-021 at OP 3: "No later than 30 days from the effective date of this order, PG&E shall file supplemental testimony in A.98-11-023 describing a permanent revenue sharing mechanism for new non-tariffed products and services."

Regarding the audit of this program, the Commission directs PG&E to retain an independent auditor, as a program expense, to perform an evaluation of this program, including the topics identified above. The auditor shall consult with Energy Division, for input as to the scope of review of the program. The Commission requires that the audit review, at a minimum, the past five years, years 2022, 2021, 2020, 2019, and 2018. PG&E shall retain an independent auditor no later than six months from the effective date of this decision. The independent consultant shall provide the Director of the Energy Division with a proposed evaluation scope of work and to allow for the Energy Division to provide input and approve of a final evaluation scope of work. Within 12 months of the effective date of this decision, the independent auditor shall produce a public audit that includes findings, conclusions, and recommendations and provide a copy to the service list of this proceeding and to the Director of Energy Division. PG&E shall submit this audit in its 2027 GRC and file and serve the audit in the application proceeding for consideration by the Commission and parties in any application proceeding initiated by PG&E seeking authorization to continue its Non-Tariffed Products and Services program.

Finally, regarding the "net transaction proceeds" equaling $135.5 million from the transaction with SBA Communication Corporation, the Commission denies PG&E's request to spread these profits over approximately 20 years by including $5.9 million in 2023.[1922] Instead, the Commission directs PG&E to provide the full amount of $135.5 million to ratepayers as revenues proportionally over the rate case period, 2023-2026. The $135.5 million will be proportionally reflected in PG&E's authorized 2023-2026 revenue requirements as an increase of $27.988 million in Other Operating Revenues to provide $33.875 million annually for 2023-2026.

6.3.2. Internal Electric Vehicle Infrastructure & Internal Fleet Electrification Program

PG&E's Electric Vehicle Infrastructure Program (which is recorded in MWC 28) is also within the broader category of Customer Engagement. PG&E states that its Electric Vehicle Infrastructure Program involves the installation of a new electric vehicle charging stations and associated infrastructure for its Internal Fleet Electrification Program to be used by PG&E employees and also serve as fleet vehicles.[1923] PG&E states that this program is supported by state policies encouraging the deployment of electric vehicles in California.[1924]

PG&E does not forecast any expense for these programs in PG&E Ex-06. PG&E's total 2023-2026 capital forecast for its Electric Vehicle Infrastructure Program and PG&E's Internal Fleet Vehicle Programs is $28.5 million for MWC 28.[1925] This forecast includes PG&E request for $18.7 million in capital expenditures for its Internal Fleet Electrification Program (MWC 28)[1926] from

[1922] PG&E Ex-10 at 16-7.

[1923] PG&E Opening Brief at 638.

[1924] PG&E Opening Brief at 638.

[1925] PG&E Ex-06 at 2-26.

[1926] PG&E Ex-19-E at 2-9 to 2-13.

2021-2026, including $6.3 million in 2023, $7.0 million in 2024, $2.2 million in 2025, and $3.3 million in 2026.[1927] PG&E proposes this increase in capital to support its goal to have 1,048 fleet Electric Vehicles in operation by 2026, starting with large facilities with early Electric Vehicles deployment in 2023 and 2024 and incremental spending in 2025 and 2026. Costs do not include procurement of vehicles.[1928] The table below sets forth PG&E's request:

Description	MWC	MAT	2021	2022	2023	2024	2025	2026	Total
EV - Infrastructure support	28	#	2,400	2,300	2,300	2,400	2,500	2,600	**14,500**
PG&E Internal Fleet Electrification	28	#	-	-	6,250	6,960	2,150	3,300	**18,660**
Total MWC 28			**2,400**	**2,300**	**8,550**	**9,360**	**4,650**	**5,900**	**33,160**

Cal Advocates recommends a reduced capital forecast for PG&E's Electric Vehicle Infrastructure Program and Internal Fleet Vehicle Program (MWC 28).[1929] Cal Advocates proposes capital expenditures of $0 in 2021, $0 in 2022, and $6.250 million in 2023.[1930] Cal Advocates describes the work reflected in MWC 28 as "deployment of electric vehicle charging stations for employees at PG&E locations across its service area" and provides no "verifiable benefit or calculated savings" to ratepayers.[1931] Cal Advocates also asserts that ratepayers already provided capital for this purpose.[1932] Similarly, TURN recommends rejecting the total capital expenditure request by PG&E because the programs have not been

[1927] Cal Advocates Opening Brief at 330; TURN Opening Brief at 535.

[1928] PG&E Ex-06-E at 2-24 to 2-26.

[1929] Cal Advocates Opening Brief at 342.

[1930] Cal Advocates Opening Brief at 343.

[1931] Cal Advocates Opening Brief at 344-345.

[1932] Cal Advocates Opening Brief at 346.

approved by the Commission and PG&E has not conducted a cost-benefit analysis to demonstrate whether the benefits justify the costs, such as the anticipated reduction of GHG emissions from the program.[1933] TURN states that during a time when ratepayers are facing unprecedented bill increases, ratepayers should not be paying for programs, such as electrification of fleet vehicles, in the absence of a persuasive reason by PG&E.[1934]

PG&E states that its initial forecast was based on the number of vehicles to be electrified, and the location and number of charging ports. And since then, it has refined its deployment plans.[1935] However, the Commission finds that PG&E has not provided such information in sufficient detail to support this forecast for these programs of $18.7 million (2021-2026).[1936] Accordingly, the Commission adopts a capital forecast of $0 for Electric Vehicle Infrastructure Program and Internal Fleet Vehicle Program (MWC 28) for 2021-2026.

6.4. Customer Services Offices

Prior to the COVID-19 PG&E's sixty-five Customer Service Offices (also referred to as CSOs) provided customers with in-person customer services, including the processing of payments. In April 2022, PG&E filed A.22-04-016 (Customer Service Offices Application) proposing to permanently close all of its Customer Service Offices.[1937] PG&E's analysis of customer payments during the

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1933 TURN Opening Brief at 535.

1934 TURN Opening Brief at 534.

1935 PG&E Ex-19-E at 2-12.

1936 PG&E Opening Brief at 638-640; PG&E Reply Brief at 526-527.

1937 D.22-12-033, *Decision Approving Joint Memorandum Of Understanding and Settlement Agreement and Resolving Disputed Issues* (December 15, 2022) in A.22-04-016 was based on a Memorandum of Understanding between PG&E, TURN, Cal Advocates, and the Center for Accessible Technology (CforAT), a Joint Settlement Agreement between PG&E and the National Diversity

Footnote continued on next page.

pandemic shows that customers that relied on Customer Service Offices successfully transitioned to other payment and assistance channels. As a result, PG&E states in its Customer Service Offices Application that it is proposing utilizing the Customer Service Offices workforce to perform proactive outreach to help customers pay their bills and enroll in assistance programs such as CARE, FERA, the Arrearage Management Plan, and Medical Baseline.[1938]

PG&E's miscellaneous capital work for Customer Services Offices is tracked in MWC 21 and is uncontested. Resolution of the expense forecast for the Customer Service Offices is discussed below.

6.4.1. Customer Service Offices – Collect Revenue

PG&E requests approval of its 2023 expense forecast of $17.991 million for its Customer Service Offices,[1939] which is $4.5 million higher (+33%) than 2020 recorded costs of $13.5 million.[1940] PG&E states that the increase is primarily attributable to hiring new Customer Service Representatives.[1941]

On December 15, 2022, in D.22-12-033 (while this proceeding was pending), the Commission authorized the permanent closure of PG&E's 65 Customer Service Offices effective January 1, 2023, and approved a proposal for PG&E to transition its Customer Service Offices employees to focus on targeted customer outreach for PG&E's vulnerable customers and other areas.[1942] The Commission also found in D.22-12-033 that "[a]s a result of this decision

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Coalition (NDC), and resolution of disputed issues between PG&E and the Small Business Utility Advocates (SBUA).

[1938] PG&E Opening Brief at 641 to 642.

[1939] PG&E Opening Brief at 641.

[1940] PG&E Ex-05 at 5-1.

[1941] PG&E Ex-05 at 5-1.

[1942] D.22-12-033 at 2.

[D.22-12-033] PG&E's ratepayers will benefit from approximately $45.7 million in estimated savings over the 2023 General Rate Case (GRC) period (2023-2026)."[1943] PG&E filed its Application in this proceeding before the Commission issued D.22-12-033 and, presumably for that reason, PG&E's forecast reflects full staffing and operation of all its Customer Service Offices.

With the benefit of the Commission's guidance in D.22-12-033, which authorized PG&E to close its Customer Service Offices, TURN recommends that PG&E's $17.991 million 2023 expense forecast[1944] be reduced by $11.195 million (MWC DWK, MWC EZ and MWC IU) to $6.796 million, which TURN explains reflects PG&E's 2021 recorded costs based on the reduced level of staffing in 2021 when the Customer Service Offices were closed due to the COVID-19 pandemic.[1945]

The Commission finds, consistent with the authorization granted in D.22-12-033 to permanently close Customer Service Offices, that TURN's recommendation of reducing the PG&E's 2023 forecast of $17.991 million by $11.195 million is reasonable, as this reduced amount reflects the general level of operation granted to PG&E in D.22-12-033 for the closure and transformation of Customer Service Offices, and the Commission applies this reduction to forecasts reflected in MWC DK, MWC EZ and MWC IU. Accordingly, the Commission adopts a 2023 expense forecast of $6.796 million.

Anticipating PG&E's reduction in revenue requirement associated with closure and transformation of Customer Service Offices, the Commission in D.22-12-033 directed PG&E to submit a Tier 2 Advice Letter within 60 days of

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1943 D.22-12-033 at 3 and 53.

1944 PG&E Ex-06 at 5-9 (Table 5-2).

1945 TURN Opening Brief at 535; TURN Reply Brief at 142-143.

this decision, which details the following: (1) the reduction to its adopted electric and gas distribution revenue requirements effective January 1, 2024 resulting from the closure of Customer Service Offices up to that date; and (2) the savings to be returned to customers that were realized from the date of the Customer Service Offices closures through December 31, 2023. The Commission also directed PG&E to submit annual Tier 2 Advice Letters in every year thereafter to account for savings associated with Customer Service Offices closures until all Customer Service Offices have closed.[1946]

In this decision, the Commission also requires PG&E to provide an explanation of the accuracy of its estimated $45.7 million in savings during this rate case period (2023-2026) in the above-referenced advice letter filings.

6.5. Compliance and Regulatory Strategy

PG&E's Compliance and Regulatory Strategy forecast supports several functions, including regulatory strategy; customer experience and insights; tariff interpretation; risk, compliance, and audit; and customer and employee privacy.[1947] PG&E's 2023 expense forecast for Compliance and Regulatory Strategy is $21.352 million, which is a $4 million (23%) increase above the 2020 recorded adjusted costs of $17.4 million.[1948] PG&E states the increase is primarily attributable to ongoing compliance activities for the California Consumer Privacy Act of 2018 and new compliance activities due to the recent passage of the California Privacy Rights and Enforcement Act of 2020.[1949] PG&E's

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[1946] D.22-12-033, Decision Approving Joint Memorandum of Understanding and Settlement Agreement and Resolving Disputed Issues (December 15, 2022) at 8 and 57 to 58.

[1947] PG&E Ex-06 at 8-1.

[1948] PG&E Ex-06 at 8-1 to 8-2.

[1949] PG&E Ex-06 at 8-2.

2023 expense forecast consists of $16.0 million for Compliance and Regulatory Strategy (MWC EZ) and $5.4 million for Customer Care (MWC OM) costs.[1950]

TURN contests PG&E's $5.4 million expense forecast for Customer Care, which is tracked in MWC OM. The 2020 recorded adjusted expense for MWC OM is $2.8 million.[1951] This forecast includes labor and employee-related costs needed to provide supervision, management, and administrative support for supervisors and managers.[1952] PG&E's $16.0 million forecast for Compliance and Regulatory Strategy (MWC EZ) is uncontested.[1953] PG&E requests that the Commission adopt its 2023 expense forecast for Compliance and Regulatory Strategy.

TURN states that PG&E's $5.4 million forecast for Customer Care (MWC OM) should be reduced by $1.9 million, the amount forecasted for Customer Care officer salaries, because officer salaries have been paid by shareholders through 2022 and PG&E has not explained why ratepayers should support this expense starting in 2023.[1954]

In response, PG&E confirms it requested a forecast that included Customer Care officer salaries in the 2020 GRC, and it did not waive its right to request officer salaries in a future forecast when compensation is not excluded by Rule 240.3b-7 of the Securities Exchange Act.[1955] PG&E does not seek cost recovery for the salaries and benefits of Chief Customer Officer and Senior Vice

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[1950] PG&E Ex-06 at 8-1 to 8-2.

[1951] PG&E Ex-08 at 8-12.

[1952] PG&E Opening Brief at 644.

[1953] PG&E Opening Brief at 644.

[1954] TURN Opening Brief at 539-540.

[1955] PG&E Ex-06 at 1A-6; PG&E Reply Brief at 528-529.

President, as both positions are designated as a Rule 240.3b-7 Officer consistent with Commission precedent.[1956] PG&E also states that "historically and routinely," the Commission allows utilities to recover the costs of utility officers as a reasonable operating cost, other than those officers who are defined by Rule 240.3b-7 of the Securities Exchange Act.[1957] Accordingly, the Commission finds the forecast for Customer Care (MWC OM) consistent with past practice and adopts a 2023 expense forecast for Customer Care (MWC OM) of $5.375 million.

6.6. Gas AMI Module Replacement Project

PG&E installed Advanced Metering Infrastructure (AMI) modules on gas meters to enable PG&E to automatically obtain meter readings from approximately 4.6 million gas meters between 2006 and 2012.[1958] The AMI modules had an expected 20-year service life. Two percent of the modules were installed in 2006 and 2007, and approximately 67% were installed in 2010 or later.[1959] PG&E explains in PG&E Ex-06 that, "As PG&E advised in its 2020 General Rate Case (GRC), the Gas AMI Modules that it installed between 2006-2012 have begun to prematurely fail and require replacement."[1960] Within the current context of failing AMI modules, PG&E proposes a forecast that

[1956] D.21-08-036, Decision on Test Year 2021 General Rate Case for Southern California Edison Company (August 19, 2021) at 418-419.

[1957] PG&E Opening Brief at 646; PG&E Reply Brief at 528-529.

[1958] PG&E Ex-06 at 9-1 and 9-8; D.06-07-027, *Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure* (July 20, 2006) (Commission approval of the installation of AMI modules, modified by D.09-03-026.)

[1959] PG&E Ex-06 at 9-1 and 9-8; D.06-07-027, *Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure* (July 20, 2006) (Commission approval the installation of AMI modules.) (Modified by D.09-03-026.)

[1960] PG&E Ex-06 at 9-1.

includes "proactively" replacing the AMI modules over the next several years beginning in 2023.[1961] Before proposing its "proactive" AMI Module Replacement project, PG&E states it engaged in a number of efforts, including "corrective maintenance" to evaluate the best option for resolving issues created by the malfunction of the equipment:

> to address the premature failures of its Gas AMI Modules, including conducting troubleshooting in the field, expanding quality assurance product testing, performing failure rate studies, and engaging its supplier to reduce the costs of replacing this equipment. In addition, PG&E has continually refined its failure rate forecast to improve its resource planning and schedule its proactive replacement plan in a way that is efficient and reduces the overall cost of this maintenance program.[1962]

PG&E concludes that its corrective maintenance approach to replacing the AMI modules is not the preferred approach and states it will begin its proactive replacements of the AMI modules in 2023.[1963]

To support its newly proposed proactive replacement efforts, PG&E requests an expense forecast of $9.4 million in 2023 and approximately $95 million in capital expenditures in 2023 (and approximately $385 million total capital expenditures in years 2024-2026).[1964] In contrast, to replace AMI modules as part of corrective maintenance (rather than proactive maintenance), PG&E forecasts costs of $94.988 million for 2023, $141.626 million for 2024, $133.560 million for 2025, and $110.310 million for 2026.[1965]

[1961] PG&E Ex-06 at 9-1 to 9-3.

[1962] PG&E Ex-06 at 9-2.

[1963] PG&E Ex-06 at 9-11.

[1964] PG&E Ex-06 at 9-2 and 9-3.

[1965] PG&E Ex-06 at 9-2, 9-3 and 9-18 (Table 9-4).

PG&E urges the Commission to adopt its forecast for proactive replacement of the AMI modules, stating as follows:

> [T]echnology and systems are a foundational asset for the Company and essential for maintaining and providing timely and accurate billing services to customers. This technology, which was groundbreaking when the CPUC first approved PG&E's implementation of it over a decade ago, has evolved and improved.[1966]

Cal Advocates, TURN, and AARP recommend removing costs associated with replacing AMI modules from PG&E's forecast, including the cost of replacing all the AMI modules that failed prematurely. In support of this recommendation, TURN argues that it is unreasonable for ratepayers to cover the full cost associated with replacement or repairs until PG&E present a proposal that shares cost between ratepayers and shareholders and, in addition, provides evidence on the degree of its responsibility for the earlier-than-expected failures of this AMI equipment.[1967] TURN also states, based on PG&E's data, the "vast majority of existing AMI Modules continue to work effectively" and suggests that PG&E's forecast of $480.50 million for proactive replacement is not justified and its forecast of $400 million for corrective replacement is "exaggerated."[1968] As such, TURN recommends a forecast of $0 and urges the Commission to deny PG&E recovery for associated costs, either via the replacement project or corrective action, until such evidence is presented.[1969]

[1966] PG&E Ex-06 at 9-14.

[1967] TURN Reply Brief at 144-145.

[1968] TURN Opening Brief at 542.

[1969] TURN Opening Brief at 544; TURN Reply Brief at 144-145.

Similar to parts of TURN's argument, AARP argues that PG&E's decision to proactively replacing AMI modules is not cost-effective. AARP opposes the need to replace 1.4 million modules, as proposed by PG&E's plan, because even using PG&E's numbers, the benefit is very small. Furthermore, AARP states that PG&E's benefit and cost estimates likely include significant variation with risk of higher costs.[1970] AARP also asserts that PG&E's assumptions for the failure rate of modules are extreme and not based on actual failure rates.

Cal Advocates recommends a two-thirds reduction in PG&E's AMI Module Replacement capital forecast for 2021, 2022, and 2023. Cal Advocates argues that forecasted AMI module replacement capital costs should be allocated in a manner that reflect the sharing of costs among ratepayers, shareholders, and the AMI module manufacturers because both the manufacturers and PG&E are partly responsible for the premature failure of the modules and, therefore, ratepayers should not be responsible for the entire extremely costly replacement plan.[1971] Cal Advocates argues that the quality of defects occurring in the modules provide evidence that PG&E bears some cost responsibility for not ensuring that the manufacturer produced a quality product consistently.[1972]

While PG&E claims that without the proactive replacement of AMI modules, costs will increase by approximately $400 million in capital expenditures above the amounts now forecasted for the corrective maintenance program,[1973] PG&E does not adequately substantiate this claim. For example, PG&E acknowledges that an additional $400 million in capital expenditures for

[1970] June 10, 2022 RT at 55-56.

[1971] CALPA Ex-05 at 14.

[1972] CALPA Ex-05 at 13.

[1973] PG&E Opening Brief at 648-649.

corrective maintenance is less than the $480.5 million in capital expenditures (including labor) proposed for proactive replacement during this rate case period (2023-2026) but also suggests that this $400 million for corrective maintenance only reflects costs expected in the 2023 GRC period and corrective action costs will only increase over time.[1974] In short, PG&E forecasts for both corrective maintenance and proactive replacement are not convincing since proactive replacement is not shown to be cost-efficient and, at the same time, the corrective maintenance forecast is just the beginning of costs and no end to costs are now known under this proposal.

In addition, the Commission is concerned about the overall magnitude of the costs forecasted for both the proactive replacement and the corrective maintenance approach. The Commission finds that, based on the information provided by PG&E to support its request, which is scant, plus the arguments by parties regarding PG&E's potential need to assume some or all of these costs, further information is needed before PG&E is able to establish by the preponderance of evidence that the cost forecast is reasonable and should be incorporated into PG&E's revenue requirement for collection from ratepayers and earn a rate of return towards shareholder profits.

The Commission finds the position presented by Cal Advocates, TURN, and AARP persuasive that the benefits predicted by PG&E from proactive AMI module replacement are relatively small and highly dependent upon assumptions regarding projected failure rates that have not been supported by evidence in the record. We acknowledge that PG&E may be correct when it claims that its forecasts reflect that the AMI module failure rate is at the

[1974] PG&E Ex-06 at 9-2, WP at 9-8, Gas Module Capital Project Forecast Summary.

crossover point where it is more cost effective to proactively replace modules than waiting to replace upon failure.[1975] However, PG&E states that risks are associated with the rate of module failure in its forecasts.[1976] Furthermore, while PG&E states that proactive replacement of AMI modules is cost-effective, the Commission is not persuaded that the cost-effectiveness of proactive replacement is well-founded and, in addition, finds that the risk of additional costs based on the proactive approach outweighs the claimed benefits. As noted by PG&E, the vast majority of the existing AMI modules continue to work effectively.[1977] PG&E's forecast for its proactive replacement plan is insufficiently supported. Regarding PG&E's forecast for its corrective maintenance plan, the Commission likewise finds it is insufficiently supported.

In addition, PG&E's proposed level of investment in AMI modules is uncertain in terms of whether such investment is necessary or provides tangible customer benefits, particularly in light of electrification goals which PG&E and other parties reference throughout this proceeding and which bear special focus at the most distributed end of the gas system.

As noted by TURN, the Commission has recognized that even when the forecasted work is necessary, a disallowance may still be warranted where (1) the utility had not originally performed the work properly; (2) the utility had failed to comply with regulatory requirements that it was previously funded to satisfy; or (3) the costs to be incurred are due to clear and identifiable failures and errors.[1978]

[1975] PG&E Ex-19 at 9-21.

[1976] PG&E Ex-19 at 9-23.

[1977] PG&E Ex-06 at 9-5.

[1978] TURN Opening Brief at 541, *citing to* D.16-06-056 at 22-23.

Accordingly, for all these reasons, the Commission adopts a forecast of $0 for replacing AMI modules for 2023-2026 in MWC EZ, MWC HY, MWC IS and MWC JV (expense); MWC 2F and MWC 74 (capital). PG&E may file a separate application seeking recovery of cost for replacement of AMI modules, but no revenue requirement is authorized in this proceeding due to the unsubstantiated nature of the forecast and PG&E's failure to propose a reasonable allocation of costs for replacement between ratepayers and shareholders that fairly reflects PG&E's errors in its AMI module business plan. No memorandum account is authorized here.

6.7. Customer Care Technology Projects

PG&E's Customer Care Technology program aims to improve areas of billing, customer service, and customer data management. The expense activities PG&E plans include ongoing maintenance, operations, and repair for PG&E's applications, systems, and infrastructure technology solutions supporting Customer Care. PG&E forecasts $21.446 million in MWC JV for 2023 expenses for this program.[1979] The capital activities that PG&E plans include costs to design, develop and enhance applications, systems, and infrastructure technology solutions.[1980] PG&E forecasts $75.6 million in MWC 2F for 2023 capital expenditures for this program. One project within this program is contested, the Billing System Upgrade.

6.7.1. Billing System Upgrade (Expense MWC JV and Capital MWC 2F)

PG&E proposes a forecast for the Billing System Upgrade Project to enable quicker rate change responsiveness for new rate programs, efficient maintenance

[1979] PG&E Ex-6 at 10-28 (Table 10-1).

[1980] PG&E Opening Brief at 658.

of existing rates programs, better billing timeliness and accuracy, and future access to additional customer service features. In support of this upgrade, PG&E states that two decades of customized changes have resulted in a lengthy and laborious process for programming new or improved rate structures that, given the increased number and complexity of approved rate programs, has resulted in a backlog given that the system must be fully tested for many months after each such structural rate change has been made to ensure the whole billing system still functions smoothly. PG&E requests a 2021-2023 forecast of $9.0 million in expense (MWC JV) and $165 million in capital (MWC 2F) for the Billing System Upgrade Project.[1981]

PG&E states that the current billing system lacks the long-term capability to meet the complex requirements for programming new structural rate changes or additions. PG&E explains that the Billing System Upgrade Project will implement a modular bill calculation framework, reducing the implementation time and costs for programming any new rate structures.[1982] PG&E further states that the project specifically implements new and complex programs that are beyond the capabilities of the current system.[1983] PG&E bases its cost estimate for the Billing System Upgrade Project on Project Estimating Tool (PET). The PET's output is based on assumptions of project size, complexity, user, and customer impact, among other things.[1984]

[1981] TURN Opening Brief at 547.

[1982] PG&E Opening Brief at 664.

[1983] PG&E Opening Brief at 660-661.

[1984] PG&E Opening Brief at 660.

TURN argues that PG&E's forecast for its Billing System Upgrade Project lacks sufficient information to evaluate.[1985] TURN states that PG&E's workpapers for the projects consist of four pages of vague and general summary statements, followed by 85 pages of promotional material from Oracle and provides "no information whatsoever regarding how the forecasted total cost of $174 million was determined."[1986] TURN states that the four-page project summary does not include timelines, implementation plans, and estimates for the resources required.[1987] TURN points to a request by SCE to upgrade its billing systems, stating that the application filed by SCE "detailed its methodology for estimating the benefit/cost ratio, including the process, benefit assumptions, how they identified total costs over project life, and total benefits over life (including direct cost savings and avoided cost savings)."[1988] Based on the lack of basic details provided by PG&E, TURN recommends that the Commission remove the forecast for the Billing System Upgrade Project and direct PG&E to file a separate application within six months of the effective date of this decision seeking authorization to include the costs associated with the Billing System Upgrade Project in its revenue requirement and that application should, at a minimum, include the following:

(1) A showing of the requirements, features, and functionalities of the new proposed system.

(2) A more robust showing of PG&E's proposed project, including the implementation plan, phases of the project (e.g., planning, development, testing, or others), resources

[1985] TURN Opening Brief at 546.

[1986] TURN Opening Brief at 547.

[1987] TURN Opening Brief at 546-547.

[1988] TURN Opening Brief at 548-550.

required for each phase, timeline for each phase, costs anticipated for each phase, and other information.

(3) A cost-benefit analysis for the project that considers whether the overall benefits of the project outweigh the overall costs.

(4) An accounting of the expected cost savings as a result of the new billing system as well as a proposal for crediting the benefits back to ratepayers.

(5) Whether the project would result in stranded investments for ratepayers as a result of previous spending on the current billing system, and the dollars associated with such stranded investments.

(6) Which components, and how much of the forecasted cost, are related to cloud-based solutions.[1989]

The Commission finds PG&E did not provide basic information to justify its forecast for the upgrade, such as how the upgrade implements programs that are beyond the capabilities of the current system and, in addition, an implementation plan and timeline. As a result, the Commission finds PG&E has failed to establish that the forecasted cost of the upgrade is reasonable since no clear benefits are identified. Accordingly, the Commission removes the forecasted costs related to the Billing System Upgrade Project, resulting in an expense forecast of $18.846 million for MWC JV for 2023 and capital expenditures forecast for MWC 2F of $27.3 million in 2023.[1990] The Commission also removes capital costs associated with this request from 2021 and 2022 forecast costs.

[1989] TURN Opening Brief at 553.

[1990] PG&E Opening Brief at 659. (The values are in Ex. PG&E-6 WP at WP 10-14 as follows: MWC JV: $0.600 and $5.800 million for 2021 and 2022 respectively; MWC 2F $7.300 and $65.200 million for 2021 and 2022, respectively.)

In addition, for the Commission to evaluate PG&E's Billing System Upgrade Project, should PG&E seek to pursue this Billing System Upgrade Project, PG&E shall file in an application before the Commission, which includes the following information, consistent with TURN's recommendations:

(1) A showing of the requirements, features, and functionalities of the new proposed system.

(2) A more robust showing of PG&E's proposed project, including the implementation plan, phases of the project (e.g., planning, development, testing, or others), resources required for each phase, timeline for each phase, costs anticipated for each phase, and other information.

(3) A cost-benefit analysis for the project that considers whether the overall benefits of the project outweigh the overall costs.

(4) An accounting of the expected cost savings as a result of the new billing system as well as a proposal for crediting the benefits back to ratepayers.

(5) Whether the project would result in stranded investments for ratepayers as a result of previous spending on the current billing system, and the dollars associated with such stranded investments.

(6) Which components, and how much of the forecasted cost, are related to cloud-based solutions.

In addition, PG&E must (7) explain how the upgrade project specifically implements new and complex programs that are beyond the capabilities of the current system.

6.8. Uncontested Costs

PG&E's uncontested expense and capital expenditure forecasts are set forth in PG&E Ex-06 and PG&E Ex-19, as revised.[1991] The Commission finds that those amounts are reasonable.

7. Shared Service and Information Technology

PG&E's shared services and information technology departments provide wide-ranging services that benefit all lines of business and various organizations. These services include the Safety Department, Transportation Services, Supply Chain – Materials Logistics and Planning, Supply Chain – Sourcing Operations, Corporate Real Estate, Environmental and Geosciences programs, Enterprise Records and Data Management, as well as information technology. PG&E states that these organizations are critical for PG&E's safety and security efforts.[1992] For instance, PG&E explains that its Safety Department is responsible for identifying, evaluating, and controlling hazards and risks to PG&E's employees and the public. It has similar responsibilities related to PG&E's Transportation Services department trucks and equipment for emergency and incident response.[1993]

PG&E's forecast for expense and capital expenditures for shared services and information technology is summarized below.[1994]

- Expense forecast for 2023 is $744.036 million. Approximately $133 million (18%) of PG&E's TY 2023 expense forecast is undisputed.
- Capital expenditures forecast is $531.425 million in 2021, $499.064 million in 2022, and $1.473 billion in 2023,

[1991] The uncontested expense and capital expenditure forecasts for Customer and Communications are set forth in Appendix A to PG&E's Opening Brief at A-14 and A-24.

[1992] PG&E Opening Brief at 667.

[1993] PG&E Opening Brief at 667.

[1994] PG&E Opening Brief at 667-668.

$628.014 million in 2024, $689.630 million in 2025, and $758.331 million in 2026. Approximately $94 million of PG&E's 2023 capital forecast (6%) is undisputed.

PG&E's expense and capital forecasts for Sourcing, Land and Environmental Management, Cyber and Corporate Security, and Geosciences are undisputed.[1995]

7.1. Party Positions and Stipulation

TURN and Cal Advocates contested issues relating to the enterprise data management and information technology forecasts. The parties' initial litigation positions as to contested enterprise data management and information technology forecasts were as follows:[1996]

1. PG&E's 2023 expense forecast for Enterprise Records and Information Management and Enterprise Data Management was $20.328 million, which included $3.8 million for the Enterprise Data Management program (MWC AB). After Cal Advocates initially opposed all of PG&E's 2023 expense forecast of $3.8 million for enterprise data management, the parties stipulated to this forecast in full.
2. PG&E's 2023 expense forecast for IT was $385.094 million,[1997] which included $420.375 million for Baseline Operations and Management and Technology Investments in Solution Delivery and Operations, Fieldwork Management, Data Enablement, and Enterprise Resource Management Expense (MWC JV). Cal Advocates recommended a reduction of $80.947 million to PG&E's 2023 expense forecast for Baseline Operations and Management and Technology Investments in Solution Delivery and Operations, Fieldwork Management, Data Enablement, and Enterprise Resource Management Expense (MWC JV). TURN recommended a

[1995] PG&E Opening Brief at 668.

[1996] PG&E Opening Brief, Appendix F at F-1 to F-3.

[1997] The total is lowered by a deduction of $36.686 million for the overhead credit.

reduction of $35.5 million to PG&E's 2023 expense forecast for MWC JV.

3. PG&E's 2023 capital forecast for IT was $265.9 million, which included Technology Investments Portfolio Core Network Infrastructure and Operations Capital (MWC 2F). Cal Advocates recommended a reduction of $58.9 million to PG&E's 2023 capital forecast for Technology Investments Portfolio Capital (MWC 2F). TURN recommended a reduction of $54.935 million to PG&E's 2023 capital forecast for Technology Investments Portfolio Core Network Infrastructure and Operations Capital (MWC 2F).

On November 30, 2022, PG&E entered into a stipulation with each of these parties to resolve most contested issues regarding enterprise data management and IT.[1998] The stipulation regarding PG&E's enterprise data management and IT 2023 expense and capital expenditures forecasts (the Enterprise Data Management/IT Stipulation) provides that it resolves all issues in PG&E Ex-07, Ch. 7 and Ch. 8, as follows:[1999]

1. For O&M for Baseline Operations and Management and Technology Investments in Solution Delivery and Operations, Fieldwork Management, Data Enablement, and Enterprise Resource Management Expense (MWC JV) a total 2023 expense forecast of $378.375 million, a reduction of $42 million to PG&E's request.
2. For Technology Investments Portfolio, including Core Network Infrastructure and Operations, Capital (MWC 2F) a total 2023 capital forecast of $259.9 million, a reduction of $6 million to PG&E's request.

No party contests this aspect of the November 30, 2022 stipulation. Cal Advocates, TURN and PG&E agree that this stipulation reflects a complete

[1998] PG&E Opening Brief at 668.

[1999] PG&E Opening Brief, Appendix F at F-3.

resolution of disputed enterprise data management and information technology issues, except for the attrition year forecasts, depreciation, and other issues reflected therein.[2000] For purposes of determining final values for each of the stipulated amounts, the parties agree that the escalation factors adopted by the Commission should apply, where appropriate, to any identified values in the stipulation.[2001]

After reviewing the uncontested stipulation that reached a reduced 2023 forecast of $48 million, i.e., reflecting $42 million in expense and $6 million in capital expenditures, the Commission finds that the stipulation of Cal Advocates, TURN, and PG&E on enterprise data management and information technology forecasts is reasonable. It is clear from the record and from the stipulations that TURN and Cal Advocates had a comprehensive understanding of the issues and facts, and the capacity to engage in the stipulation process. Therefore, the Commission adopts this stipulation as presented.

PG&E's uncontested expense and capital expenditure forecasts set forth in PG&E Ex-07, Ch. 7 and Ch. 8, Shared Services and Information Technology are found reasonable.[2002]

The remaining disputed issues presented in PG&E Ex-07, Shared Services and Information Technology, are discussed below.

[2000] PG&E Opening Brief, Appendix F at F-1.

[2001] PG&E Opening Brief, Appendix F at F-1.

[2002] PG&E Opening Brief at Appendix A, A-15 to A-17 and A-24 to A-25.

7.2. Enterprise Health and Safety and Occupational Health

PG&E states that the Enterprise Health and Safety Department (EHS) is responsible for identifying, evaluating, and controlling hazards, risks, and exposures with the objective to protect PG&E's employees and contractors, and the public.[2003] Through the *One PG&E Occupational Health and Safety Plan*, EHS provides a governance role over the elements of workforce and public safety, while the execution of the programs themselves is performed by specific lines of business. Occupational Health includes PG&E's workers compensation, disability, and on-site health care programs.[2004]

PG&E's Enterprise and Occupational Health forecasts are comprised of two broad categories: (1) Enterprise Health and Safety (uncontested 2023 expense forecasts of $38.617 million),[2005] and (2) Occupational Health, which were partially opposed. PG&E's 2023 expense forecast for Occupational Health, which is a companywide expense, is $156.420 million.[2006] PG&E's 2023 forecasts for On-Site Clinics, Fit for Duty, Department of Transportation Drug Testing, and Substance Abuse Intervention are uncontested and found reasonable.[2007]

7.2.1. Transitional Light Duty Payroll

PG&E's light-duty payroll will pay the wages of employees who are returned to work in a light or transitional capacity and meet certain criteria. For Transitional Light Duty Payroll (workers' compensation programs), PG&E

[2003] PG&E Ex-07 at 1-1.

[2004] PG&E Opening Brief at 668-669.

[2005] PG&E Opening Brief at 669 (reflects forecast in PG&E Ex-64 (JCE) at 3-5.)

[2006] PG&E Ex-07 at 1A-22 (reflects forecast in PG&E Ex-64 (JCE) at 3-19).

[2007] PG&E Opening Brief at Appendix A.

forecasts $5.610 million for 2023.[2008] PG&E's forecast is based on an actuarial study conducted by Willis Towers Watson, which used the weighted average of the 2015-2019 recorded data and gave the most weight to 2019 and gradually less weight to each prior year to forecast the 2020 payments.[2009] PG&E then adjusted those results to account for forecast labor escalation for 2021-2023.[2010]

For Transitional Light Duty Payroll (WC Programs) for 2023, Cal Advocates recommends a lower forecast of $5.116 million. Cal Advocates bases its recommendation on a using the five-year average from 2016-2020 due to fluctuations in costs as a result of normal changes in activity levels.[2011]

PG&E did not explain the rationale for giving the most weight to the 2019 data and did not use the 2020 recorded data, which is the most recent data. Cal Advocates does not adjust its results to account for forecast labor escalation for 2021-2023, which it did not dispute. Using the unweighted five-year average of 2016-2020, as proposed by Cal Advocates, the figure adjusted for escalation is $6.004 million (which is greater than PG&E's forecast).[2012] Considering the labor escalation rate from 2021-2023, which Cal Advocates did not dispute, Cal Advocates does not address how its methodology would produce a lower forecast.[2013] Considering the above, the Commission finds that PG&E's 2023 expense forecast for Transitional Light Duty Payroll (WC Programs) is supported and reasonable and adopts PG&E's forecast of $5.610 million.

[2008] PG&E Opening Brief at 671.

[2009] PG&E Opening Brief at 671.

[2010] PG&E Opening Brief at 672.

[2011] CALPA Ex-11 at 57-58

[2012] PG&E Opening Brief at 672.

[2013] Cal Advocates Opening Brief at 346.

7.2.2. Voluntary Plan and Third-Party Disability Management

PG&E states that it offers a modified sick leave program, including a short-term disability program paid through a Voluntary Plan.[2014] PG&E manages disability and other leave programs on a coordinated basis, using a single, third-party administrator.[2015] PG&E explains that the third-party administrator assures that PG&E's compliance is up to date with overlapping local, state, and federal laws and regulations governing disability and other leave policies, including medical leaves and the Family Medical Leave Act.[2016] PG&E states that it offers the Voluntary Plan (short-term disability and Paid Family Leave) as a supplemental benefit in lieu of a State of California plan.[2017] PG&E forecasts $22.297 million in expense for 2023 for the Voluntary Plan (short-term disability and Paid Family Leave benefits) and $1.772 million for the Third-Party Disability Program Management costs, resulting in a combined 2023 forecast of $24.069 million.[2018]

For PG&E's 2023 expense forecast for the Voluntary Plan and the Third-Party Disability Program Management, Cal Advocate recommends a much lower 2023 expense forecast of $2.052 million. Cal Advocates states that PG&E's forecast for these services increase from $2.052 million in 2016 to $20.2 million in 2020 due to a voluntary plan offered in addition to a state plan that is provided at no cost to employees and therefore not included in rates. Cal Advocates

[2014] PG&E Opening Brief at 672.

[2015] PG&E Opening Brief at 672.

[2016] PG&E Opening Brief at 672.

[2017] CALPA Ex-11 at 62.

[2018] PG&E Opening Brief at 672.

maintains that the state plan is a reasonable substitute for PG&E voluntary program that provides benefits for most California employees and is fully supported by employee contributions, not by ratepayers.[2019] As a result, Cal Advocates bases its forecast on the expense recorded in 2016, before PG&E's voluntary program offered supplemental benefits to employees.[2020]

In response, PG&E states that Cal Advocates' recommendation ignores that the cost of compensation and benefits has risen in the last five years, and that Cal Advocates has no justification to specifically select 2016 for forecasting. In addition, PG&E states that there are cost reductions in salaries and benefits resulting from the voluntary plan, such as decreased employee unavailability due to health.[2021]

The Commission finds Cal Advocates' use of 2016 data as a basis for its recommendation reasonable because it was the last recorded year before the expansion of PG&E's Voluntary Program. Furthermore, the Commission finds PG&E's explanation of cost reductions resulting from the Voluntary Program to be unsupported because PG&E has not stated, in dollar amounts, the exact amount of savings and to what extent that has offset the increased forecast. Accordingly, the Commission finds PG&E's 2023 forecast of 2023 of $24.069 million unpersuasive and, instead, finds reasonable Cal Advocates' recommendation for a 2023 expense forecast based on 2016 data and adopts a 2023 forecast for the Voluntary Plan and the Third-Party Disability Program Management of $2.052 million.

[2019] CALPA Ex-11 at 62.

[2020] CALPA Ex-11 at 62; Cal Advocates Opening Brief at 388; Cal Advocates Reply Brief at 57-58.

[2021] PG&E Opening Brief at 673; PG&E Reply Brief at 548.

7.2.3. Trust Contributions to Long-Term Disability Benefits

PG&E states that long-term disability benefits provide partial income replacement and continued medical and life insurance coverage to employees who are unable to work due to their disability. PG&E funds disability benefits by making contributions to trusts.[2022] For disability benefits, PG&E forecasts $45.313 million for 2023.

Cal Advocates recommends a lower 2023 forecast for trust contributions of $30.869 million based on a five-year average of costs that have been trending downward from 2016-2020 and Cal Advocates questions PG&E's justification for a 50% increase over 2020 recorded data.[2023]

In response, PG&E claims that its forecast is consistent with prudent trust funding principals, actuarial practices, and past Commission decisions, which were not opposed in the 2020 GRC proceeding (which resulted in a settlement).[2024] PG&E states that consistent with D.07-03-044, it uses a consolidated approach for adopted contribution amounts for the Post- Retirement Benefits Other than Pension and Long-Term-Disability (LTD). That means that PG&E contributes the amount allowable under Internal Revenue Service guidelines and provides a credit to customers if some portion of the Commission approved contribution cannot be contributed on a tax-deductible basis.[2025] Lastly, PG&E states that if Cal Advocates' five-year average were to be

[2022] PG&E Ex-07 at 1A-17 to 1A-19.

[2023] CALPA Ex-11 at 59-60.

[2024] PG&E Reply Brief at 586.

[2025] PG&E Reply Brief at 586-587.

consistently applied to all aspects of the program, it would result in a total forecast of $63 million.[2026]

Although Cal Advocates has not addressed all of PG&E's arguments, the Commission finds that PG&E has not persuasively explained the basis for the over 50% increase in disability benefits, when PG&E's recent spending was trending downwards. As a result, PG&E's request is not reasonable. Instead, the Commission finds Cal Advocates' recommendation reasonable. Accordingly, the Commission adopts Cal Advocates 2023 forecast for disability benefits of $30.869 million.

7.2.4. Wellness Programs

PG&E's Wellness programs include, but are not limited to, Health Screenings and Coaching, Flu Shot Clinics, and Tobacco Cessation programs. Wellness programs are intended to help employees and their dependents increase their awareness of, and take actions to improve, their health, to prevent illness, to produce an engaged and healthy workforce, and thereby promote safer and more efficient utility operations. PG&E requests a 2023 expense forecast of $6.340 million for its Wellness program based on a five-year average of costs from 2016-2020.[2027] PG&E states that it used the five-year average in its forecast because it accounts for fluctuations over time and is adjusted for escalation and a forecasted increase in employees.[2028]

Cal Advocates recommends a lower 2023 expense forecast for wellness programs of $3.838 million, which is $2.502 million lower than PG&E's forecast. Cal Advocates bases its forecast on the three-year average from 2018-2020 to

[2026] PG&E Reply Brief at 587.

[2027] PG&E Opening Brief at 674.

[2028] PG&E Opening Brief at 548-549.

reflect the more current expense trend and is lower because it does not include the higher costs in 2016 and 2017 of approximately $7.2 million in each year.[2029]

Cal Advocates contends that this three-year average reflects a trend toward lower Wellness program expenses. But Cal Advocates does not support the reason for that trend or refute PG&E's forecast for increased Wellness program expenses. On the other hand, the Commission finds that PG&E offers a reasonable explanation for its use of the five-year average. Accordingly, the Commission adopts PG&E's 2023 expense forecast for Wellness programs of $6.340 million.

7.2.5. Employee Assistance Program

PG&E states that its Employee Assistance Program is a work-based intervention program designed to assist employees in resolving personal problems that may adversely affect performance. PG&E explains that its Employee Assistance Program assists workers with issues like alcohol or substance use disorders, relationship challenges, financial or legal problems, emotional issues, stress, wellbeing, and traumatic events like workplace violence, coworker accidents or deaths, or natural disasters. PG&E request an expense forecasts of $2.604 million for 2023 for its Employee Assistance Program.[2030] This forecast is based on a five-year average, adjusted for the number of employees and escalated to 2023.[2031]

Cal Advocates recommends a lower 2023 expense forecast for the Employee Assistance Program of $1.859 million. Cal Advocates bases its forecast on the three-year average from 2018-2020 and proposes the alternate because it

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[2029] CALPA Ex-11 at 57 and 64 (Table 11-26).

[2030] PG&E Opening Brief at 675.

[2031] PG&E Ex-20 (Rebuttal) at 1A-10 to 1A-11.

claims that PG&E did not provide discussion on these programs in its testimony nor any support in its workpapers.[2032]

In response, PG&E maintains that its forecast is reasonable because it is based on historical expenses, an estimated per employee per month increase, and estimated headcount adjustments,[2033] which Cal Advocates' forecast methodology does not.[2034] The Commission finds PG&E's forecast to be supported by its explanations and reasonable. Cal Advocates' arguments are not fully convincing. Accordingly, the Commission adopts PG&E's 2023 expense forecast for its Employee Assistance Program of $2.604 million.

7.2.6. Mental Health Services

PG&E states that its Mental health services (also referred to as EAP-Medical) include one-on-one confidential support for a variety of life events and concerns. According to PG&E, individuals are eligible for up to six sessions per six-month period. Mental health services can support many individual concerns, such as family and relationship problems, workplace concerns, alcohol and drug issues, depression, anxiety, and stress at home or work. PG&E explains that this is an important component of its Health and Wellness Management Programs since employee issues can negatively affect work performance and safety on the job and at home.

PG&E requests an expense forecast of $19.530 million for Mental Health Services in 2023.[2035] PG&E's 2023 expense forecast for Mental Health Services

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[2032] CALPA Ex-11 at 64.

[2033] PG&E Ex-20 (Rebuttal) at 1A-11.

[2034] PG&E Ex-20 (Rebuttal) at 1A-10 and 1A-11; PG&E Opening Brief at 675-676. PG&E Ex-07 at 1-14.

[2035] PG&E Opening Brief at 676-677.

includes $979,000 for Substance Abuse Intervention,[2036] which PG&E agreed not to fund in a separate category. PG&E's forecast is based on a forecast provided by Mercer, which considers PG&E's plans, PG&E employee demographics, and the Northern California environment.[2037]

Cal Advocates recommends a lower 2023 forecast for Mental Health Services of $13.683 million. Cal Advocates bases its forecast on a three-year average from 2018-2020 and claims that PG&E's forecast is not supported.[2038]

PG&E contends that Cal Advocates' recommendation should be rejected for two reasons. First, PG&E contends that Cal Advocates' forecast does not take into consideration increased costs arising from the COVID-19 pandemic. PG&E claims that the COVID-19 pandemic increased the number of people experiencing mental health symptoms. In addition, California law now requires providers to give mental health and substance abuse patients a follow-up visit within 10 days.[2039] Second, PG&E states that Mercer's report is reliable because the 2021 actual mental health costs were 98% of the forecast provided by Mercer in support of PG&E's original funding.[2040]

However, a review of the explanation of PG&E's forecast of Healthcare Cost of Medical Plans provided by Mercer in PG&E's workpapers[2041] indicates that the information provided is for the cost of medical plans as a whole, which includes medical services beyond mental health. The Commission find this to be

[2036] PG&E Ex-20 at 1A-2; CALPA Ex-11 at 65.

[2037] PG&E Opening Brief at 677.

[2038] CALPA Ex-11 at 63-64.

[2039] PG&E Opening Brief at 676.

[2040] PG&E Reply Brief at 549-550.

[2041] PG&E Ex-08 at WP 5 Vol. I-15-WP 5 Vol. I-22.

insufficient support for the more specific mental health forecast. Accordingly, the Commission finds PG&E's forecast for Mental Health Services for 2023 to be unsupported and Cal Advocates' forecast based on a three-year average to be reasonable. Accordingly, the Commission adopts Cal Advocates 2023 Mental Health Services forecast of $13.683 million.

As a result of the above reductions, the Commission adopts a forecast for Occupational Health, companywide expenses, for 2023 of $112.201 million.

7.3. Transportation and Aviation Services

PG&E's Transportation and Aviation Services includes transportation services and aviation services organizations.[2042] PG&E states that, together, these organizations manage over 14,000 vehicles and related equipment utilized across PG&E's service territory.[2043] This includes all vehicles, construction equipment, trailers and aircraft, including rentals, supporting safe, reliable and efficient service.[2044] PG&E's Transportation and Aviation Services 2023 net expense forecast is $118.082 million and its capital expenditures forecast is $107.569 million.[2045]

Cal Advocates' recommended 2023 net expense forecast for transportation and aviation Services is $105.301 million, which is $12.781 million lower than PG&E's expense forecast for 2023. Cal Advocates' adjustments to PG&E's requests occur in the Fuel and Vehicle subcategories of Transportation Services (MWC AB) and in Overhead Credit (MWC ZC).[2046] Cal Advocates does not

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[2042] PG&E Opening Brief at 678.

[2043] PG&E Opening Brief at 678.

[2044] PG&E Opening Brief at 678.

[2045] PG&E Opening Brief at 550.

[2046] Cal Advocates Opening Brief at 346-347.

oppose PG&E's total capital expenditures request 2021-2023 for Transportation and Aviation of $98.678 million, $64.677 million, and $107.569 million, respectively.[2047]

7.3.1. Transportation Services Expense

PG&E's transportation services expenses tracked in MWC AB includes vehicles, depreciation, fuel, and rentals. PG&E states that it estimated the vehicles forecast primarily by using historic costs including labor, parts, registration and freight. PG&E's 2023 net expense[2048] forecast for Transportation Services (MWC AB) is $117.167 million ($265.767 million gross before application of Overhead Credit). PG&E states that its fuel and rentals forecasts are estimated using historic costs in relation to work plans and targets forecast by the separate lines of business. PG&E states that its fuel expense supports day-to-day operations as well as emergency events such as wildfire.[2049]

PG&E 2023 expense forecasts for the fuel portion of Transportation Services (MWC AB) is $18.8 million (approximately 16%of the MWC AB forecast of $117.167 million for miscellaneous expense in MWC AB.)[2050] PG&E states that the primary drivers of the forecasted expense increase are (1) escalation; (2) higher costs to operate the fleet, including maintenance, fuel, labor and rentals; (3) increased depreciation costs inclusive of base fleet and additional book value associated with green fleet lifecycle replacements; and IT initiatives

[2047] Cal Advocates Opening Brief at 362.

[2048] Once the gross forecast is determined, any portion of the forecast that is funded by capital or balancing account orders (overhead credit) is removed, resulting in a net forecast. PG&E-07 at 2-3 (fn. 2).

[2049] PG&E Opening Brief at 679.

[2050] PG&E Opening Brief at 679.

for system and database enhancements.[2051] PG&E bases its fuel expense forecast on a growth rate of 1.55% based on the average increase in miles driven per employee over a three-year (2017-2019) historical period and mobile fuel consumption calculated using a five-year (2016-2020) average that was adjusted for outliers with a 3% rate of escalation in 2021 to 2023.[2052]

Cal Advocates recommends a net fuel expense reduction of $3.459 million to PG&E's forecast for MWC AB in 2023[2053] using the historical two-year average (2018-2019) of fuel consumption. Cal Advocates states that, while 2017 appears to be an outlier year, PG&E's historical fuel usage in 2018-2019 approximates usage patterns from 2016 to 2020. Cal Advocates also contends that its net fuel expense reduction reflects PG&E's stated goal of relying on hybrid and electric vehicles, renewable diesel, and renewable natural gas-powered vehicles.[2054]

In response, PG&E claims Cal Advocates' use of 2017-2019 historical average ignores the growth in consumption documented by PG&E.[2055]

Upon review, the Commission finds that PG&E does not reconcile its projected growth rate with its program to reduce one million tons of greenhouse gas emissions from company operations through 2022 using 2016 emissions as a baseline.[2056] PG&E also does not explain why it includes depreciation costs in MWC AB, as described above, which should be accounted for separately as depreciation costs. Accordingly, the Commission finds that a lower forecast for

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[2051] PG&E Opening Brief at 677-678.

[2052] PG&E Opening Brief at 679-680.

[2053] Cal Advocates Opening Brief at 348; PG&E Opening Brief at 379.

[2054] Cal Advocates Opening Brief at 347-348.

[2055] PG&E Reply Brief at 550-551.

[2056] Cal Advocates Opening Brief at 347-348.

fuel expense based on the 2017-2019 historical average and emissions policies to be reasonable and adopts a reduction in PG&E's Transportation Services (MWC AB) net expense forecast for 2023 of $3.459 million to $113.708 million.

7.3.2. Vehicle Expense

PG&E's expense forecast for vehicles includes costs to maintain and deploy safe, reliable, compliant, cost-effective vehicles and equipment to provide gas and electric services to PG&E customers 24 hours a day, 365 days a year. PG&E's forecast for vehicle expense (MWC AB) is $41.1 million (approximately 35% of the total 2023 net expense forecast of $117.167 million for MWC AB).[2057]

Cal Advocates recommends a net reduction of $2.442 million a lower forecast of ($3.153 million gross reduction) for PG&E's 2023 Transportation Services (MWC AB) based on a lower number of employees.[2058] Cal Advocates states that it applied the same union employee-driven vehicle-to-employee ratio of 35:1 and forecasts 457 employees compared to 459 forecasted by PG&E. In support of its forecast, Cal Advocates states that PG&E does not have plans to incrementally add vehicles to the currently existing fleet and did not include any capital requests for an increase in incremental assets.

In response, PG&E states that although its vehicle fleet may not have grown significantly, vehicle maintenance workload has increased due to fire risk reduction initiatives, increased regulatory inspection requirements, and vehicle safety campaigns.[2059] In addition, PG&E states that underestimating staffing can result in increased overtime, lower vehicle availability and delays in repair

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[2057] PG&E Opening Brief at 680.

[2058] PG&E Opening Brief at 680.

[2059] PG&E Opening Brief at 681.

times.[2060] Based on the above, the Commission finds PG&E staffing level estimate and the related Labor forecast to be reasonable and adopts PG&E's 2023 vehicle expense forecast of $41.1 million without reduction.

7.3.3. Transportation Overhead Credit

PG&E's Transportation Overhead Credit is tracked in MWC ZC and is the expense amount of the offsetting credit of transportation overhead that is applied (debited) to applicable capital and balancing account expense projects.[2061] For Transportation Overhead Credit, PG&E forecasts a credit of $149.762 million in 2023.[2062] PG&E's forecast is based on three years of recorded data from 2017-2019 and explains that it used only these three years of recorded data because the "Fleet Overhead" credit is no longer applied to balancing account expense orders for 2020 GRC period-jurisdictional balancing accounts, as of 2020. In the 2023 GRC, PG&E proposes to extend this accounting treatment to GT&S balancing accounts.[2063]

Cal Advocates recommends a larger credit of $156.642 million for the Transportation Overhead Credit based on five years of historic data (2016-2020). Cal Advocates contends that using two additional years of data provides a more accurate representation because it includes more recent data and incorporates more variation in the results of operations as well as unforeseen changes to the business.[2064]

2060 PG&E Reply Brief at 551-552.

2061 PG&E Opening Brief at 681.

2062 PG&E Opening Brief at 681 to 682.

2063 PG&E Opening Brief at 682.

2064 Cal Advocate Opening Brief at 149.

The Commission finds that Cal Advocates' suggestion to use a five-year historical average for this forecast is not appropriate because the 2020 data does not reflect the cost model change PG&E has applied in this GRC. Accordingly, the Commission does not increase the Transportation Overhead Credit and adopts PG&E's forecast for the Transportation Overhead Credit (Expense MWC ZC) $149.762 million for 2023.

7.3.4. Automotive Fleet Equipment

PG&E's Fleet Automotive Equipment (MWC 04) includes capital expenditure forecasts for vehicle replacements based on the useful lives of different asset types. According to PG&E, its transportation services vehicle replacement plan aligns with the overall goals to provide safe, reliable, compliant, and cost-effective vehicles and equipment to provide gas and electric services.[2065]

7.3.4.1. PG&E Request

PG&E's costs for Automotive Fleet Equipment are tracked in MWC 04 and PG&E's capital expenditure forecast is $104.811 million in 2023, $105.972 million in 2024, $143.951 million in 2025, and $244.138 million in 2026. The primary driver of the increases over 2023-2026, including the substantial increase in 2026, is planned vehicle replacements based on the useful lives of different asset types.[2066]

PG&E's vehicle and equipment replacement plan includes capital replacement funding for lifecycle replacement, compliance replacements, and accident replacements. PG&E's lifecycle replacement accounts for approximately 98% of its 2023 capital expenditure forecast of $104.811 million for Fleet

[2065] PG&E Opening Brief at 682-683.

[2066] PG&E Opening Brief at 682-683.

Automotive Equipment (MWC 04). PG&E states that electric vehicle purchases will increase the lifecycle replacement capital expenditure forecast by $2.2 million in 2023, $2.5 million in 2024, $2.9 million in 2025, and $4.8 million in 2026.[2067]

In support of its forecast, PG&E states that electrifying vehicles at the end of the useful life of existing vehicles allows PG&E to leverage existing planned funding for existing vehicles to lower the overall costs of replacing gas-powered vehicles with electric vehicles. More specifically, PG&E plans to purchase sport utility vehicles and half-ton pickup trucks in 2023. PG&E plans to equip certain aerial bucket trucks with plug-in Jobsite Energy Management Systems, which enables aerial booms to operate on full electric power and will help eliminate engine idling at the jobsite.[2068]

7.3.4.2. Party Positions

TURN contends that PG&E has not conducted a cost-benefit analysis to demonstrate whether the benefits of EV purchases, including the anticipated reduction in greenhouse gas emissions, as part of its fleet electrification proposal are justified by the increased 2023 capital cost of $12.4 million for EV purchases.[2069]

AARP contends that PG&E has not analyzed whether the economic advantages of such EV purchases outweigh the costs to ratepayers. In support of its position, AARP states that the absence of such an analysis is clear since PG&E will "be spending more than the worth of the entire vehicle on repairs."[2070]

[2067] PG&E Reply Brief at 553-554.

[2068] PG&E Opening Brief at 553-554.

[2069] TURN Opening Brief at 555-556.

[2070] AARP Opening Brief at 15.

AARP contends further that the question of repair costs vs. vehicle value is not relevant. Instead, AARP suggests that the relevant question is whether repairing existing vehicles or buying new vehicles is less expensive for customers.[2071] In that regard, AARP states that PG&E's argument about unproductive field crew costs is exaggerated. As a result, AARP concludes that PG&E fails to appreciate the value of equipment with operational life remaining simply because that equipment is fully depreciated (and thus earning no rate of return on investment).[2072]

In addition, AARP recommends a capital reduction of $229 million from 2023 to 2026, based on its comparison of PG&E's forecast capital spending to the 2017-2022 average of $75.7 million and AARP's proposal to extend PG&E's planned heavy vehicle purchases by several years.[2073] AARP argues that with good maintenance, vehicles can remain in safe and reliable condition long past the end of their depreciation period. AARP posits that extending planned vehicle purchases out a few years to moderate the increase in vehicle replacement costs resulting from Air Resources Board regulations is unlikely to cause reliability or safety issues of significance.[2074]

PG&E states that the $75.7 million relied upon by AARP has an artificially low number of Class 7 and 8 heavy-duty trucks due to accelerated purchases in prior years prompted by Air Resources Board regulations. Secondly, AARP's observation that "vehicles can remain in safe and reliable condition long past the end of their depreciation period" is based on its witnesses' experiences with their

2071 AARP Opening Brief at 15.

2072 AARP Opening Brief at 15.

2073 PG&E Opening Brief at 683

2074 AARP Opening Brief at 43-44

own personal vehicles, not on any knowledge of the wear and tear on, or required additional maintenance on, PG&E's heavy-duty truck fleet.[2075]

7.3.4.3. Discussion

The Commission must balance emission reduction goals with the cost of achieving them and have sufficient information to substantiate such a decision. PG&E proposes a forecast to accommodate the purchase of sport utility vehicles, half-ton pickup trucks, and fully electric aerial booms on for bucket trucks. However, PG&E has not provided sufficient information to establish that this forecast is reasonable. For instance, PG&E does not provide the factors needed to make such a decision, including how many vehicles and other equipment PG&E proposed to purchase. What is the difference in cost between electric vehicles and equipment and non-electric models? What savings in fuel and maintenance may be achieved by purchasing electric vehicles and other equipment? PG&E also has not described whether other sources of funding have already been authorized for transportation electrification that may be used for electrifying PG&E's vehicles.[2076] Accordingly, at this time the Commission does not approve of increased capital expenditures for purchasing electric powered vehicles and equipment as opposed to non-electric powered vehicles and equipment in this GRC separate from other funding sources.

The Commission may approve a reasonable cost for the replacement of non-electric vehicles. However, the Commission does not find sufficient information regarding such a forecast in the record. Future requests for such funding should include information regarding the cost of maintaining vehicles

[2075] PG&E Opening Brief at 684.

[2076] TURN Opening Brief at 555.

beyond by repairing them instead of replacing them. In the interim, the Commission denies the increase in the capital cost of $12.4 million. By deducting this amount from the forecast of $104.811 million,[2077] the Commission adopts a forecast for Automotive Fleet (capital MWC 04) in 2023 of $92.411 million.

With regard to the AARP's recommendation to reduce capital spending by extending PG&E's planned purchase of vehicles, the Commission finds insufficient analysis of the maintenance costs. To maintain the safety and reliability of PG&E's vehicle fleet, which is relied upon to respond to emergencies, the Commission denies the AARP's recommendation.

7.4. Materials

PG&E's 2023 expense forecast for materials tracked in MWC AB is $1.704 million.[2078] PG&E's materials capital expenditure forecast for 2023 is $1.2 million.[2079] PG&E's Materials includes the expense and capital expenditures forecasts for PG&E's Material and Distribution Operations department as well as the Materials and Supplies (M&S) inventory forecast. Materials manages a materials distribution network throughout PG&E's service territory in support of its maintenance and construction activities. PG&E's capital expenditure forecast is not contested.

Cal Advocates recommends reducing PG&E's 2023 Materials (MWC AB) expense forecast to $529,000.[2080] Cal Advocates bases its recommendation on an

[2077] PG&E Opening Brief at 683.

[2078] PG&E Opening Brief at 685

[2079] PG&E Opening Brief at 685.

[2080] Cal Advocates Opening Brief at 349-350.

analysis of recorded costs for MWC JL from 2016-2020 that would result in a credit.[2081]

PG&E did not provide a forecast for MWC JL, which tracks the recorded standard cost variance for this material expense. PG&E states that it did not forecast a standard cost variance for MWC JL because "[v]ariances in the material burden overhead and material consumption rates that drive cost allocations are unpredictable and the periodic refinement of the material burden rate attempts to get the net cost as close to the $0 as possible."[2082]

Although it is unclear why PG&E did not provide a forecast for MWC JL, the Commission does not find Cal Advocates' recommendation to be persuasive. Accordingly, the Commission does not adopt Cal Advocates recommended credit for Materials expense and adopts PG&E's 2023 materials expense forecast (MWC AB) of $1.704 million.

7.5. Sourcing

PG&E states that Sourcing is responsible for the procurement of goods and services and provides oversight for day-to-day supply chain activities and functional guidance to all PG&E departments regarding all procurement policies and procedures.[2083] In addition, PG&E states that Sourcing supports PG&E's supplier diversity and sustainability efforts.[2084] PG&E's 2023 expense forecast is $26.837 million.[2085] PG&E's capital expenditures forecast is $0.470 million in 2021,

[2081] Cal Advocates Opening Brief at 349-350.

[2082] PG&E Reply Brief at 554-555.

[2083] PG&E Opening Brief at 687.

[2084] PG&E Opening Brief at 687.

[2085] PG&E Opening Brief at 687.

$0 in 2022, and $0 in 2023.[2086] PG&E's expense and capital forecast are undisputed and the Commission finds these forecasts reasonable.

7.6. Real Estate

PG&E's Corporate Real Estate Strategy and Services (CRESS) organization governs, plans, acquires, designs, constructs, operates, and maintains 7.7 million square feet of facilities throughout PG&E's service territory. These facilities include service centers, data centers, contact centers, office buildings, shops, warehouses, construction and equipment yards, vehicle maintenance garages, customer service offices, and meeting and training facilities.[2087]

PG&E states that the primary drivers of increases to the real estate expense forecast are escalation, activities to transition from COVID-19 work-from-home conditions to more normal operations, and the headquarters move from San Francisco General Office to the Oakland General Office. The primary reason for the increase in capital expenditures is the purchase of and transition to the Oakland General Office and investment in service centers.[2088]

7.6.1. Manage Properties and Buildings

PG&E forecasts $109.527 million for Manage Properties and Buildings, which are tracked in MWC EP. The Manage Property & Buildings category includes facility services to maintain appropriate levels of operational readiness and reliability for facilities, grounds, buildings, and systems. Typical services include janitorial, repairs and maintenance, landscape management, purchase of utilities such as water, sewer, gas, electricity, waste disposal and recycling services, rent and operating expense for leased facilities, mail delivery, and

[2086] PG&E Opening Brief at 687.

[2087] PG&E Opening Brief at 687-688.

[2088] PG&E Opening Brief at 688.

conference center services. The services tracked in MWC EP include the Conference Centers Program and Facilities Management Program.[2089]

As discussed below, Cal Advocates recommends a reduction of $14.412 million, split between two activities – Conference Centers Program and Facilities Management Program.[2090]

7.6.2. Conference Centers Program

The Conference Centers program provides for the operation and maintenance of PG&E's conference and training facilities, which include the San Ramon Valley Conference Center (SRVCC), Livermore Electric Safety Academy, Winters Gas Safety Academy, and San Francisco General Office Conference Center (which will transition to Oakland).[2091]

For the Conference Center Program in 2023, PG&E's forecast is $12.051 million. PG&E contends that several factors support its forecast. First, PG&E states that its request reflects plans to return to normal operations. These plans include the training and conference volumes of at least pre-bankruptcy and/or pre-pandemic volumes. Second, PG&E states that its forecast reflects increasing costs due to implementing new COVID-19 protocols. Lastly, PG&E's 2023 forecast also reflects expected loss of external revenue credits previously realized through third-party conference center rentals.[2092]

Cal Advocates recommends a reduction in the Conference Center Program expenses in 2023 of $3.813 million, lowering the forecasted 2023 expenses to $8.238 million. Cal Advocates' recommendation utilizes a two-year historical

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[2089] PG&E Opening Brief at 688-689.

[2090] PG&E Opening Brief at 688-689.

[2091] PG&E Opening Brief at 689.

[2092] PG&E Opening Brief at 689-691.

average of years 2018 and 2019 and a different methodology.[2093] Cal Advocates opposes PG&E's Conference Center Program forecast because PG&E bases its record level spending forecast on 2020 recorded data, unsubstantiated assumptions related to return-to-normal patterns, new COVID-19 protocols, and a projected loss of external revenue.[2094]

Cal Advocates forecast for the Conference Center Program is based on an average of the two years of recorded data prior to the onset of the COVID-19 pandemic in 2020. This is the most recent pre-pandemic data for the Conference Center Program. PG&E requests an increase of $3.813 million for this program based on a projected increase in the volume of training and conferences to pre-pandemic volumes. But PG&E does not provide a better source of data to substantiate the basis for increased costs, including why COVID-19 protocols continue to be necessary in a return to normal operations, how such protocols would increase costs, and the volume and cost of increased activity. Accordingly, the Commission finds that an average of the 2018-2019 data to provide a reasonable estimate of Conference Center Program costs and adopts a 2023 forecast of $8.238 million for the Conference Center Program.

7.6.3. Facilities Management Program

The Facilities Management program provides the service to operate and maintain the Company's facilities that are managed by Corporate Real Estate Strategy and Services (CRESS) and includes building management such as the CRESS Facilities Services team and its alliance partner costs, janitorial and enhanced cleaning, repairs to existing facilities for break/fix items, routine

[2093] PG&E Opening Brief at 689-690.

[2094] Cal Advocates Opening Brief at 351-352.

maintenance – including periodic testing and inspection, landscape maintenance and repairs, and site and yard maintenance – such as road repair, drainage maintenance, and perimeter fence repair.[2095] For the Facilities Management Program in 2023, PG&E forecasts $45.600 million based on 2020 recorded data.[2096]

Cal Advocates recommends a 2023 expense reduction in the Facilities Management Program of $10.599 million. Cal Advocates bases its recommendation on a four-year average (2016-2019) of pre-pandemic costs adjusted for a varying level of costs associated with its San Francisco General Office.[2097]

PG&E states that its 2023 forecast is based on an alignment of company targets with operational and strategic changes to the portfolio. PG&E then contends that Cal Advocates use of 2016-2019 data does not represent PG&E's future facility management program costs. However, PG&E does substantiate how one-year of 2020 data at the beginning of the pandemic represents such future costs better than the 2016-2019 four-year average of pre-pandemic data. PG&E also does not sufficiently substantiate how the 2020 data better reflects changes in its general office costs.[2098] Accordingly, the Commission adopts Cal Advocates recommendation to reduce PG&E's Facilities Management Program forecast for 2023 within MWC EP by $10.599 million. Combined with the reduction to MWC EP for the Conference Center Program in Section 7.6.1.1 above of $3.813 million, the Commission adopts a reduction to the 2023 forecast for MWC EP of $14.412 million to $95.115 million.

[2095] PG&E Opening Brief at 691.

[2096] Cal Advocates Opening Brief at 350.

[2097] CALPA Ex-10 at 22-23; Cal Advocates Opening Brief at 350-351.

[2098] PG&E Opening Brief at 691-692.

7.6.4. Line of Business Wildfire Mitigation Support

PG&E's 2023 expense forecast for Line of Business Wildfire Mitigation Support is $1.1 million, which are tracked in MWC IG.[2099] The Line of Business Wildfire Mitigation Support program captures costs to support materials and equipment, office and yard space, and increased personnel to directly support wildfire mitigation initiatives such as inspections, grid hardening, emergency generation, and other initiatives directly related to mitigating catastrophic wildfires.

Cal Advocates recommends denying PG&E's 2023 forecast for $1.1 million for fire risk mitigation costs in this proceeding because Cal Advocates states that these costs have been recorded in the Fire Risk Mitigation Memorandum Account (FRMMA) where they will be subject to a reasonableness review after they are incurred. The FRMMA supports the Wildfire Safety Inspection Program (WSIP), which provides wildfire mitigation, monitoring and response management efforts.[2100]

PG&E states that these costs were previously recorded in the FRMMA because they were unknown at the time PG&E filed the 2020 GRC. Now, PG&E contends that since these ongoing costs can be forecast, it is appropriate to include a forecast for these costs in this proceeding and the resulting revenue requirement.

In D.19-09-026, the Commission stated that the inability to forecast costs in a GRC is one of the pre-requisites for tracking costs in a memorandum

[2099] PG&E Opening Brief at 692; Cal Advocates Opening Brief at 352.

[2100] Cal Advocates Opening Brief at 352-353.

account.[2101] Where costs can be forecast in the GRC, there is no need to track them in a memorandum account. The fact that there is a memorandum account where these costs have been recorded previously does not support continued memorandum account treatment for these forecastable costs. Further, the amount of this forecast is not in dispute and is necessary to support wildfire mitigation work. Accordingly, the Commission adopts PG&E's 2023 expense forecast for Line of Business Wildfire Mitigation Support (MWC IG) of $1.1 million.

7.6.5. Building Services Overhead Credit

The Building Services Overhead Credit tracked in MWC ZC represents the offsetting credit as building services overhead is applied (debited) to applicable capital and balancing account expense projects. PG&E forecasts a building overhead services credit of $62.171 million for 2023[2102] based on three years (2017-2019) of recorded data. PG&E states that the use of this recorded data provides a historical reference without going too far back to miss incorporating any changes to the business (i.e., wildfire support, system hardening, etc.). PG&E's forecast was further adjusted to lower the credit because PG&E will stop applying this overhead credit to almost all balancing account expense orders.[2103]

Cal Advocates recommends an increase in the Building Overhead Services Credit of $4.384 million to $66.555 million using five years of data (2016-2020), as opposed to PG&E's use of three years of data (2017-2019). Cal Advocates contends that five years of data (2016-2020) is more appropriate for this forecast

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[2101] D.19-09-026 at 6; *see also*, D.20-05-042 at 6.

[2102] PG&E Opening Brief at 694.

[2103] PG&E Opening Brief at 695.

because the five-year period incorporates more changes than a three-year period.[2104]

In response, PG&E states that five years of historical data fails to account for the cost model changes PG&E proposes to implement in 2023, which will fundamentally change the composition of the overhead allocation. PG&E states further that there is not five years of data available under the 2020 GRC cost model, and PG&E has accounted for the 2023 cost model change in its forecast.[2105] Given the changes in the cost model that PG&E has incorporated, the Commission finds PG&E's forecast for the 2023 Building Overhead Credit to be reasonable and adopts it in the amount of $62.171 million.

7.6.6. Real Estate Strategy Implementation

Real Estate Strategy Implementation is tracked in MWC 23. This forecast is for activities that provide strategic portfolio and financial planning and governance; real asset development, planning, design, and project delivery services, and other activities to maintain PG&E's workspaces in compliance with local codes, standards, and ordinances. PG&E forecasts $1,007.521 million in 2023, $141.3 million in 2024, $139.0 million in 2025, and $130.0 million in 2026 for MWC 23.[2106]

Cal Advocates and AARP recommend reductions are related to: (1) PG&E's San Francisco General Office/Lakeside Project; (2) the Aviation Center Project; and (3) security fencing at service centers, which are addressed below.

[2104] Cal Advocates Opening Brief at 353.

[2105] PG&E Opening Brief at 694-695; Reply Brief at 557.

[2106] PG&E Opening Brief at 695.

7.6.7. General Office Relocation

To relocate PG&E's general office from San Francisco to Oakland, the Commission approved a settlement agreement governing the sale of the San Francisco General Office with an option to purchase the Lakeside Drive office in 2023 for a forecasted and allocated amount of $892 million based on a preliminary cost buildup including cost to purchase and redevelop.[2107] PG&E requests approval to include in its 2023 capital forecast $892 million for the sale of the San Francisco General Office complex and the option to purchase 300 Lakeside Drive in Oakland,[2108] pending exercise of the option.

AARP opposes the purchase of the property and recommends leasing instead of purchasing.[2109] Cal Advocates does not oppose the purchase but recommends that the purchase price and any transition costs be removed from the PG&E's 2023 capital forecast and that PG&E be required to record those costs to a memorandum account for review following the actual purchase of the Lakeside Drive Building.[2110]

In D.21-08-027, the Commission ordered the following:

1. Pacific Gas and Electric Company will track the costs associated with moving its corporate headquarters to the building at 300 Lakeside Drive in Oakland, California through the General Office Sale Memorandum Account (electric) and the General Office Sale Memorandum Account (gas).[2111]

[2107] D.21-08-027, Decision Authorizing Pacific Gas and Electric Company's Sale of Its San Francisco General Office Complex and Related Matters (August 19, 2021).

[2108] PG&E Opening Brief at 696.

[2109] PG&E Opening Brief at 696.

[2110] Cal Advocates Opening Brief at 354-355.

[2111] D.21-08-027, Decision Authorizing Pacific Gas and Electric Company's Sale of Its San Francisco General Office Complex and Related Matters (August 19, 2021), OP 5.

2. Pacific Gas and Electric Company (PG&E) must file a petition for modification within 90 days of PG&E's exercise of its option to purchase the building at 300 Lakeside Drive in Oakland, California (Lakeside Building), wherein PG&E will request a reasonableness review and cost recovery of actual costs incurred in connection with the move to, and leasing and operation of, the Lakeside Building (including the final amount paid to purchase the building), and the leaseback of portions of the San Francisco General Office Complex, through approximately the date of the purchase of the Lakeside Building.[2112]
3. In the event Pacific Gas and Electric Company (PG&E) does not exercise its purchase option for the building located at 300 Lakeside Drive in Oakland, California (Lakeside Building), PG&E may file an application for recovery of the costs relating to the Lakeside Building lease, including but not limited to tenant improvements, lease rate, and letter of credit costs within 90 days of the exercise option date.[2113]

In accordance with D.21-08-027, the costs associated with moving PG&E's corporate headquarters to the building at 300 Lakeside Drive in Oakland, California shall be tracked through the General Office Sale Memorandum Account (electric) and the General Office Sale Memorandum Account (gas), including PG&E's exercise of its option to purchase or lease the Oakland property. As a result, the Commission denies inclusion of $892 million purchase price in PG&E's 2023 capital forecast for MWC 23.

[2112] D.21-08-027, Decision Authorizing Pacific Gas and Electric Company's Sale of Its San Francisco General Office Complex and Related Matters (August 19, 2021), OP 10.

[2113] D.21-08-027, Decision Authorizing Pacific Gas and Electric Company's Sale of Its San Francisco General Office Complex and Related Matters (August 19, 2021), OP 11.

7.6.8. Aviation Center Project

The costs to support Aviation Services Project are tracked in MWC 23. To reduce operating expense from leasing aviation properties, PG&E plans to develop an Aviation Operations Center (AOC). This project includes the development of a centralized aviation operations center adjacent to one of Northern California's regional public airports and a drone operations and maintenance facility. The AOC would support PG&E fixed wing, helicopter, and drone fleets with asset storage, light maintenance and office spaces for Aviation Services personnel, including dispatch. PG&E states that developing an AOC supports its longer-term goal of Aviation Services to develop a centralized fleet and support operations center,[2114] which PG&E claims will increase operational efficiencies, safety, and compliance.[2115] PG&E projects a start date of January 1, 2023 and completion date of December 31, 2023, by which time PG&E proposes to locate a preferred site, enter into a purchase agreement, purchase and develop the property.[2116] PG&E forecasts $25 million for this capital project.[2117]

Cal Advocates recommends denying the request for funding the AOC for several reasons. First, PG&E has not indicated when it will complete the proposed Aviation Operations Center or use the requested funds by the December 31, 2023 proposed completion date. Second, PG&E has not demonstrated that the Center would actually reduce operating expense from leased aviation properties.[2118]

[2114] Cal Advocates Opening Brief at 698.

[2115] PG&E Opening Brief at 560-561.

[2116] Cal Advocates Opening Brief at 356.

[2117] PG&E Opening Brief at 698-699.

[2118] Cal Advocates Opening Brief at 356-357.

In response, PG&E contends that Cal Advocates erroneously assumed that the project timeline is unrealistic because of the time needed to purchase a property when PG&E plans to lease the property instead. In addition, PG&E states that Cal Advocates assumes that the sole purpose of the project is to demonstrate future cost savings.[2119] However, the Commission finds that PG&E has not substantiated any cost savings associated with the project. In addition, the Commission finds that PG&E has not sufficiently demonstrated how the project funds will be used in 2023 and how the project will increase operational efficiencies, safety, and compliance compared to existing operations. Accordingly, the Commission excludes $25 million[2120] from PG&E's 2023 capital forecast for the AOC.

7.6.9. Service Center Security Fencing Program

The Service Center Security Fencing program will enhance perimeter security and fencing to reduce threat of physical attack and/or criminal trespass by ensuring perimeter security and access control systems and features are compliant with PG&E's Corporate Security standards.[2121]

In its testimony, AARP proposed a 2023-2026 capital reduction of $9.0 million per year based on its claim that the Corporate Security standard requiring new facility fencing is an arbitrary change in PG&E standards meant to justify rate increases. In addition, AARP contends that increases in standards are not always based on actual risk data.

PG&E claims that AARP's recommendation is unsupported for several reasons, including PG&E documentation of the risk of physical attack and the

[2119] PG&E Reply Brief 560-561.

[2120] PG&E Opening Brief at 699.

[2121] PG&E Opening Brief at 699-700.

need for increased security at PG&E's facilities.[2122] AARP did not include any discussion or additional support for this disallowance in its brief.[2123] Accordingly, the Commission denies AARP's recommended reduction in PG&E's capital forecast for MWC 23 for security fencing. This brings the total forecast for Real Estate Strategy Implementation (MWC 23) for 2023 to $90.521 million.[2124]

7.6.10. San Ramon Facility

This project pertains to moving employees out of the San Ramon Bishop Ranch BR1Y leased office space and restoring the building to return it to the landlord.[2125] PG&E's initial forecast for MWC JH was $7.787 million. Cal Advocates recommended a reduction of $1.176 million based on a forecasting error. After reviewing Cal Advocates' testimony, PG&E agreed and indicated that it would correct the error identified by Cal Advocates' and reduce its forecast by $1.176 million.[2126] Accordingly, the Commission adopts a forecast for 2023 Real Estate Strategy Implementation (MWC JH) of $6.611 million.

7.6.11. Enterprise Risk Management

The Enterprise and Operational Risk Management (EORM) organization is responsible for implementation and governance of the EORM Program and, on a temporary basis, for governance and oversight of wildfire risk management. The EORM organization provides the lines of business with the tools, methods, and technical support to identify, evaluate, prioritize, mitigate, and monitor risk

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[2122] PG&E Opening Brief at 700 -701.

[2123] PG&E Opening Brief at 561.

[2124] $90.521 = $1007.521 (2023 forecast) - $892 (general office relocation) - $25 million (AOC).

[2125] PG&E Opening Brief at 700.

[2126] PG&E Opening Brief at 693-694.

inherent in PG&E's operations. PG&E forecasts 2023 expenses for its EORM organization of $8.006 million.[2127] This represents a 129% increase over EORM's 2020 base expenditures.[2128] These costs are tracked in MWC KZ.

Cal Advocates recommends a 50% reduction in PG&E's $8.006 million 2023 forecast based on risk-sharing considerations and insufficient support for PG&E's additional staffing proposal.[2129]

In response, PG&E states that successful implementation of the EORM framework, tools, and program benefits customers by helping to lower the likelihood and/or severity of events with safety, reliability, or financial consequences for customers. In addition, PG&E describes how the scope and function of the EORM organization has expanded since the previous GRC and the forecast presented reflects the additional functions as well as the portion of the EORM function transferred from the Risk and Audit program.[2130]

Based on the above, the Commission finds that PG&E's 2023 expense request of $8.006 million for the EORM organization is a reasonable forecast of utility service that benefits PG&E's customers and that the cost for additional staff is necessary for EORM to provide service to PG&E's customers. Accordingly, the Commission adopts PG&E's 2023 expense forecast for its EORM organization of $8.006 million.[2131]

[2127] PG&E Opening Brief at 714-716.

[2128] Cal Advocates Opening Brief at 358.

[2129] Cal Advocates Opening Brief at 358-359.

[2130] PG&E Opening Brief at 715-716.

[2131] PG&E Opening Brief at 714-716.

7.7. Uncontested Costs

PG&E's presents uncontested 2023 expense and uncontested 2021, 2022, and 2023 capital expenditure requests in PG&E Ex-07 Shared Services and Information Technology.[2132] The Commission finds those amounts to be reasonable.

8. Human Resources

This Section addresses the forecasts set forth in PG&E's Ex-08 Human Resources. PG&E employs approximately 25,000 employees and 12,000 contractor workers.[2133] PG&E's union-represented employees are about 60% of PG&E's total workforce.[2134] PG&E's Human Resources (HR) departments are responsible for workforce planning, hiring, and employee development.[2135] PG&E has several HR departments: (1) HR Solutions and Services, (2) HR Service Delivery and Inclusion, (3) Benefits, and (4) PG&E Academy. PG&E provides forecasts for HR "department" expenses and, in addition, PG&E presents forecasts for "companywide" expenses for employee benefits and compensation-related programs.[2136] PG&E also presents a capital forecast. An overview of these forecasts is set forth below:

PG&E's forecast for 2023 is $1.029 billion for HR "department" and "companywide" expenses, divided as follows:[2137]

[2132] The uncontested expense and capital expenditure forecasts for Shared Services and Information Technology are set forth in Appendix A to PG&E's Opening Brief at A-15, A-16, A-17 (expense) and A-24, A-25 (capital).

[2133] PG&E Ex-08 at 1-1.

[2134] PG&E Ex-08 at 2-14.

[2135] PG&E Ex-08 at 1-1.

[2136] PG&E Ex-08 at 1-3; PG&E Ex-08 at 1-2 to 1-5.

[2137] PG&E Opening Brief at 717.

- $85.4 million expense forecast for 2023 HR department costs.
- $944.5 million expense forecast for 2023 HR companywide costs.
- PG&E presents the following capital forecasts regarding HR:
- Capital expenditures forecast is $1.6 million in 2021, $1.2 million in 2022, $1.2 million in 2023, $1.2 million in 2024, $1.2 million in 2025 and $1.2 million in 2026.

PG&E states that the 2023 HR companywide forecast of $944.5 million is a $259 million increase compared to 2020 recorded costs of $685.9 million (approximately 38% increase over 2020 recorded adjusted).[2138] PG&E states that the 2023 HR department costs forecast of $85.4 million is approximately a 5% increase, as compared to the 2020 recorded costs of $81.3 million.[2139] PG&E states that this 5% increase in its forecast for HR department costs is primarily driven by the following: (1) labor escalation, (2) the addition of three full-time equivalents to support HR Service Delivery and Inclusion, and (3) PG&E Academy.[2140] PG&E states that the 2023 forecast for HR companywide expense is driven largely by forecasted increases in the following: (1) $142.3 million for Medical (Utility) expenses, (2) $94.0 million Short-Term Incentive Program (STIP) primarily based in labor escalation, and (3) $10.9 million for the Workforce Transition Program.[2141] These forecasts include expenses for PG&E and two affiliates, PG&E Corporation and PG&E Support Services II. The estimated

[2138] PG&E Opening Brief at 717.

[2139] PG&E Opening Brief at 717.

[2140] PG&E Ex-08 at 1-2.

[2141] PG&E Opening Brief at 718.

affiliates expense totals to $3.074 million.[2142] Cal Advocates contests aspects of PG&E's forecast for Human Resources and recommends $829.567 million, a reduction of $365.221 million.[2143]

Regarding HR capital costs, PG&E states that HR capital costs are associated with information technology projects and costs to support PG&E Academy training, such as building upgrades and tools and equipment.[2144] PG&E's HR capital expenditures forecast is set forth above. No party contests PG&E's 2023 capital expenditure forecast.

Regarding "deferred work" and in accordance with Section 5.2 of the 2020 Deferred Work Settlement Agreement, PG&E states it is obligated make an additional showing in its 2023 GRC testimony for work that was previously requested and authorized based on representations that the work was needed to provide safe and reliable service.[2145] PG&E refers to this as "deferred work."[2146] PG&E states that there is no deferred work, as defined by Section 5.2 of the 2020 Deferred Work Settlement Agreement.[2147]

Regarding an employee headcount forecast, PG&E presents an employee headcount forecast in PG&E Ex-08, which PG&E relies upon to adjust the forecast for many of its HR companywide expenses (e.g., benefits, including

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[2142] Affiliates forecast is comprised of $663,000 for STIP, $2,155,000 for Non-Qualified Retirement and $256,000 for Employee Benefits. *See,* PG&E-08 WP 4-2, PG&E-08 WP 4-17, and PG&E-08, Ch. 5 at 5-43 (Table 5-4).

[2143] Cal Advocates Opening Brief at 385.

[2144] PG&E Opening Brief at 718.

[2145] PG&E Ex-08 at 1-5 to 1-6.

[2146] PG&E Ex-08 at 1-5 to 1-6.

[2147] PG&E Ex-08 at 1-5 to 1-6.

medical, dental, vision).[2148] PG&E's aggregate actual employee headcount at the end of years 2020 and forecasted headcount for 2021, 2022 to 2026, are as follows.

Table 8-A:
PG&E Forecast Headcount 2020-2026[2149]

Year End	2020 actual	2021	2022	2023	2024	2025	2026
PG&E's Total Employee Headcount	25,600	27,312	27,492	27,587	27,609	27,141	27,227

PG&E states that its employee headcount forecast shows a significant 4% increase in 2021, then a forecasted decrease in 2025, and explains that the 2025 decrease to 27,141 is primarily attributed to the decommissioning of the Diablo Canyon Power Plant, offset by increases in Electric Operations.[2150] Except for Cal Advocates, no party contested the actual and forecasted headcount presented by PG&E. Cal Advocates raises an issues regarding PG&E's headcount in the context of Retirement Savings Plan. The Commission addresses the headcount issue in the discussion related to Retirement Savings Plan below.

The chart below illustrates the contested areas of PG&E's Ex-08 Human Resources forecast. Cal Advocates contests PG&E's forecast in numerous areas. TURN proposes revisions but those are not reflected in the below chart. No other parties contests PG&E's forecast.

[2148] PG&E Ex-08 at 2-4.

[2149] PG&E Opening Brief at 721; PG&E Ex-08 at 2-5.

[2150] PG&E Ex-08 at 2-5.

Table 8-B:
Contested Areas in PG&E's forecast for Human Resources[2151]

	Description	PG&E Proposed (millions)	Cal Advocates Recommendation (millions)	Difference (millions)
HR Department Expenses	HR Solutions & Services	$23.439	$21.204	$2.235
	HR Service Delivery & Inclusion	$21.323	$19.018	$2.305
	Benefits	$2.284	$1.909	$375
	PG&E Academy	$38.341	$35.386	$2955
HR Companywide Expenses	Workforce Transition	$14.654	$6.638	$8.016
	Tuition Refund	$3.892	$2.982	$910
	STIP	$232.561	$87.212	$145.349
	SERP	$3.698	$1.850	$1.848
	Health & Welfare	$536.271	$394.747	$141.524
	Post-Retirement	$145.684	$144.301	$1.383
	Other Benefits	$8.121	$6.319	$1.802
	Workers Comp/On-Site	$55.719	$55.225	$494
	LTD/STD	$69.410	$32.949	$36.461
	Wellness/EAP/DOT	$30.329	$20.255	$10.074
Total		**$1,185.726**	**$829.995**	**$355.731**

The contested matters are addressed below.

8.1. HR Solutions and Services

HR Solutions and Services is one of PG&E's HR departments and this department provides support to company leaders, employees, some retirees, and other HR departments.[2152] HR Solutions and Services also leads workforce

[2151] CALPA Ex-11 at 3.

[2152] PG&E Ex-08 at 2-1.

planning and knowledge transfer activities.[2153] HR Solutions and Services is made up of two teams: (1) HR Solutions, and (2) HR Services.[2154]

HR Solutions is composed of seven functions: (1) HR Solutions Immediate Office, (2) Benefits, (3) HR Reporting and Analytics, (4) Workforce Planning, Risk & Compliance, (5) HR Emergency Management Support, (6) HR Labor Relations and Operations, and (7) HR Project Management Office.[2155]

HR Services is also composed of seven functions: (1) HR Service Immediate Office, (2) HR Solutions Center, (3) HR Business Partners, (4) Job Bidding, Hiring Hall, and Testing, (5) Employee Relations, (6) Labor Relations Service Center, and (7) HR Technology of Programs.[2156]

8.1.1. PG&E

PG&E's 2023 forecast for HR Solutions and Services is $23.7 million, a $1.9 million (approximately 9%) increase, compared to 2020 recorded adjusted of $21.6 million.[2157] PG&E requests the following 2023 forecast for HR Solutions and Services:

- $23.7 million in expense ($23.4 million in department costs plus $288,000 thousand in IT expense.)[2158]
- $0.620 million for IT capital expenditures in 2021, $0 in 2022, and $0 in 2023-2026.[2159]

[2153] PG&E Ex-08 at 2-1.

[2154] PG&E Ex-08 at 2-6.

[2155] PG&E Ex-08 at 2-6.

[2156] PG&E Ex-08 at 2-7; PG&E Ex-08 at 2-17.

[2157] PG&E Ex-08 at 2-14 to 2-16. PG&E Ex-08, Ch. 2, Table 2-2 sets forth the HR Solutions and Services costs and forecasts by FERC account.

[2158] PG&E Ex-08 at 2-1 and 2-16.

[2159] PG&E Opening Brief at 724.

PG&E states that its forecasted increase in expense costs of approximately 9% compared to 2020 recorded costs of $21.6 million is primarily driven by labor escalation (i.e., salaries), not staffing increases.[2160]

PG&E's IT expense forecast for HR is uncontested. PG&E's requested capital expenditures for IT for 2021 of $620,000 is uncontested.[2161]

8.1.2. Party Positions

Cal Advocates recommends a 2023 department expense forecast for HR Solutions and Services of $21.204 million, which is a $2.23 million reduction to PG&E's forecast of $23.439 million for HR Solutions and Services department costs.[2162] Cal Advocates recommends changes to PG&E's forecasted expense as follows: (1) $18.54 million in A&G Salaries ($1.924 million reduction to PG&E's forecast of $20.464 million), and (2) $1.92 million in Outside Services Utility ($0.311 million reduction to PG&E's forecast of $2.231 million).[2163] Cal Advocates and PG&E disagree on the appropriate forecasting methodology for A&G Salaries and Outside Services Utility.[2164]

Cal Advocates recommends a forecast for A&G Salaries of $18.54 million.[2165] Cal Advocates requested 2021 recorded data that PG&E did not provide; as a result, Cal Advocates recommends a five-year average cost for A&G Salaries.[2166] PG&E supports its A&G Salaries forecast based on based on

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[2160] PG&E Opening at 722.

[2161] PG&E Ex-08 at 2-16 (Table 2-3); PG&E Ex-8 at 2-17 (Table 2-4.); Cal Advocates Opening Brief at 387.

[2162] Cal Advocates Opening Brief at 386.

[2163] Cal Advocates Opening Brief at 387; PG&E Opening Brief at 722.

[2164] Cal Advocates Opening Brief at 387-388.

[2165] Cal Advocates Opening Brief at 387-388.

[2166] Cal Advocates Opening Brief at 387-388.

standard labor escalation.[2167] PG&E also confirms that it is not forecasting a staffing increase in 2023, as compared to 2020.[2168]

Regarding Outside Services Utility, Cal Advocates recommends a 2023 forecast of $1.92 million (a reduction of $0.311 million to PG&E's forecast of $2.231 million) using a five-year historical average of nominal dollars to calculate the 2023 forecast for Outside Services Utility.[2169] Cal Advocates states that PG&E has not supported the increase and unexplained fluctuations in historical data exist.[2170] PG&E states that its forecasted increase is related to the need for increased outside support for HR Operation.[2171] PG&E further states that Cal Advocates' recommendation for a reduction to PG&E's forecast of $0.311 million for Outside Services Utility does not account for cost escalation.[2172] PG&E states that Cal Advocates' recommendation for Outside Services Utility should include escalation, calculated on average base year dollars, resulting in $2 million, in contrast to Cal Advocates' lower forecast of $1.92 million.[2173]

8.1.3. Discussion

Based on Cal Advocates' conclusion that that HR Solutions and Services A&G Salaries costs were trending down from 2016-2019, with a slight increase in 2020, Cal Advocates requested 2021 recorded data from PG&E to further analyze

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[2167] PG&E Ex-08 at 2-14.

[2168] PG&E Opening Brief at 722; PG&E Ex-08 at 2-14.

[2169] CALPA Ex-11 at 8-12; PG&E Opening Brief at 719-722; Cal Advocates Opening Brief at 387-388.

[2170] CALPA Ex-11 at 9.

[2171] PG&E Opening Brief at 723.

[2172] PG&E Opening Brief at 723; Cal Advocates Opening Brief at 387.

[2173] PG&E Opening Brief at 723.

the trend.[2174] PG&E did not provide this information. The Commission finds that this salary forecast should reflect labor escalation, which Cal Advocates does not include. The Commission also finds the use of the five-year historical average is reasonable because of the trend but this methodology results in a forecast of $21.7 million if labor escalation is included, which is higher than Cal Advocates' forecast of $18.54 million and PG&E's forecast of $20.464 million.[2175] Accordingly, the Commission adopts a forecast for A&G Salaries expense for HR Solutions and Support of $20.464 million, which includes labor escalation, and is lower than an outcome which would include escalation based on Cal Advocates' methodology.

Regarding the Outside Services Utility, the Commission finds that the use of a five-year average, which was recommended by Cal Advocates, is reasonable for forecasting purposes because Outside Services Utility costs have fluctuated in prior years with no clear trend demonstrated by the data provided by PG&E. The Commission finds that PG&E did not carry it burden of proof that its 2023 forecasted increase is related to increased support costs. The Commission finds reasonable PG&E's position that the forecast for Outside Services Utility in HR Solutions and Support should account for cost escalation. For these reasons, the Commission agrees with PG&E's calculation of $2.09 million based on a five-year average which accounts for escalation for Outside Services, an amount that is higher than the $1.92 million recommended by Cal Advocates but lower than PG&E's requested forecast of $2.231 million.[2176] Accordingly, the Commission adopts a 2023 expense forecast of $2.09 million for Outside Services Utility in HR

[2174] Cal Advocates Opening Brief at 387-388.

[2175] PG&E Ex-21 (Rebuttal) at 2-7.

[2176] PG&E Ex-21 (Rebuttal) at 2-7.

Solutions and Support. In summary, the Commission adopts a total 2023 expense forecast for HR Solutions and Services of $23.298 million, a $141,000 reduction from PG&E's forecast.

8.2. Human Resources Service Delivery and Inclusion

PG&E's HR Service Delivery and Inclusion includes the (1) Talent Acquisition and Internal Mobility (Talent), (2) Leadership and Employment Development, (3) Performance and Inclusion, and (4) Compensation functions.[2177] PG&E's forecast for HR Service Delivery and Inclusion includes department costs and a forecast for its companywide program expenses, such as Workforce Transition,[2178] which includes Severance, Outplacement, and Tuition Assistance.[2179] PG&E presents its forecast of HR companywide program expense together with the department costs under HR Service Delivery and Inclusion.[2180] PG&E requests a 2023 expense forecast, as follows:

- $21.323 million forecast for department costs within HR Service Delivery and Inclusion for 2023 (increase of $2.5 million or 13% over $18.840 million recorded adjusted expense in 2020).[2181]
- $18.5 million forecast in companywide expense for Workforce Transition and Tuition in 2023 within HR Service Delivery and Inclusion.[2182]

[2177] PG&E Ex-08 at 3-1.

[2178] PG&E's Workforce Transition Program provides financial and career resource support to impacted employees and is designed to provide them time to transition into new positions at PG&E or pursue employment opportunities elsewhere. PG&E Opening Brief at 727.

[2179] PG&E Ex-08 at 3-1 and PG&E Ex-08 at 3-9 and 3-10. The tuition refund program encourages employees to further their education by offering a reimbursement of up to $8,000 a year.

[2180] PG&E Ex-08 at 3 presents forecasted costs for 2023 totaling $39.869 million.

[2181] PG&E Ex-08 at 1-8 (Table 1-1); PG&E Ex-08 at 3-8 (Table 3-1).

[2182] PG&E Ex-08 at 3-1.

8.2.1. PG&E

With respect to department costs for HR Service Delivery and Inclusion, PG&E requests a forecast of $21.323 million, which includes $14.447 million for A&G Salaries and $5.462 million for Outside Services Utility.[2183] PG&E states its 2023 forecast for department costs is $2.5 million (approximately 13%) higher than the 2020 recorded costs ($18.840 million) and explains that this increase is primarily driven by labor escalation, the addition of two full-time equivalent employees supporting HR Investigations and Workforce Development departments, and an increase in contracts and materials primarily to support Workforce Development and Diversity, Equity and Inclusion efforts.[2184] Regarding PG&E's forecast for Outside Services Utility of $5.462 million, PG&E states that the forecast increase for outside services is related to increased support for Workforce Development and Diversity, Equity and Inclusion efforts compared to 2020, with recorded adjusted costs of $4.613 million.

Regarding companywide expenses within HR Service Delivery and Inclusion, PG&E requests a 2023 forecast of $18.546 million for Workforce Transition Program companywide expenses in PG&E Ex-08, Ch. 3.[2185] This includes its forecast of $14.546 million for Severance/Transitional Pay (which is approximately $7 million higher than the 2020 recorded adjusted cost of $6.7 million).[2186] PG&E's companywide forecast is based on a five-year forecast and PG&E states that a five-year forecast is the same methodology adopted by in

[2183] PG&E Ex-08 at 3-13, Table 3-1 and Table 3-2; PG&E Opening Brief at 727.

[2184] PG&E Opening Brief at 725.

[2185] PG&E Ex-08 at 3-13, Table 3-1 and Table 3-2; PG&E Opening Brief at 727.

[2186] PG&E Ex-08 at 3-13, Table 3-1 and Table 3-2; PG&E Opening Brief at 727.

PG&E's 2014 GRC and relied upon by PG&E in its last two GRC filings.[2187] This Workforce Transition Program companywide forecast also includes PG&E's Tuition Refund forecast for 2023 of $3.9 million (approximately 86% higher than the 2020 recorded adjusted costs of $2.091 million.[2188]

8.2.2. Party Positions

Cal Advocates recommends a $19.018 million forecast for department costs for HR Service Delivery and Inclusion, which includes $13.320 million for A&G Salaries (a reduction of $1.127 million to PG&E's forecast of $14.447 million) and $4.284 million in Outside Services Utility (a reduction of $1.178 million to PG&E's forecast of $5.462 million).[2189]

Concerning the companywide expenses forecast for Workforce Transition, Cal Advocates recommends $9.620 million for Workforce Transition (a reduction of $8.926 million to PG&E's forecast of $18.546 million).[2190] Cal Advocates states that PG&E fails to justify its forecast of $18.546 million for Workforce Transition, which is an increase of approximately 110.44% compared to PG&E's 2020 recorded adjusted costs of $8.813 million.[2191] Cal Advocates' recommendation is $8.926 million or 48% less than PG&E's 2023 forecast.[2192] Regarding Workforce Transition-Severance/Transitional Pay, Cal Advocates recommends $6.56 million (a reduction of $7.70 million or approximately 54% to PG&E's

[2187] PG&E Opening Brief at 728.

[2188] PG&E Ex-08 at 1-8 (Table 1-1); PG&E Ex-08 at 3-1.

[2189] Cal Advocates Opening Brief at 389.

[2190] Cal Advocates Opening Brief at 389.

[2191] Cal Advocates Opening Brief at 390; PG&E Ex-08 at 3-13.

[2192] Cal Advocates Opening Brief at 390.

2023 forecast of $14.268 million).[2193] Regarding Workforce Transition-Outplacement Assistance, Cal Advocates recommends $78,000 (a reduction of $308,000 or approximately 75% to PG&E's forecast of $386,000).[2194] For the Workforce Transition-Tuition Refund, Cal Advocates recommends $2.982 million, a reduction of $910,000 from PG&E's $3.892 million request.[2195]

No party opposed PG&E's recommendation for Diversity, Equity and Inclusion, which includes scholarships.[2196] Scholarships awarded by PG&E are funded primarily with employee donations and are not included in PG&E's forecast.[2197]

8.2.3. Discussion

With respect to A&G Salaries within the department costs of HR Service Delivery and Inclusion, the Commission finds that A&G Salaries costs were trending down from 2016-2019 with a slight increase in 2020. The Commission finds PG&E fails to carry its burden of proof to explain this 2020 anomaly and did not respond to a request by Cal Advocates for 2021 recorded data. As a result, Cal Advocates could not engage in further analysis. Therefore, the Commission finds the use of a five-year historical average 2016-2020 reasonable. Consistent with PG&E's recommendation, the Commission finds that labor escalation should be included in this forecast. However, because a five-year

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[2193] CALPA Ex-11 at 14.

[2194] Cal Advocates Opening Brief at 391; CALPA Ex-11 at 15.

[2195] Cal Advocates Opening Brief at 391.

[2196] PG&E Ex-08, Ch. 3A presents PG&E's Report on Diversity, Equity and Inclusion (DEI), provides information on the diversity of PG&E's workforce and a summary of activities PG&E has undertaken to continue toward its goal of having a workforce that reflects the communities PG&E serves. PG&E Opening Brief at 724.

[2197] PG&E Ex-08 at 3A-6 Section 3.a; PG&E Ex-08 at 3A-6. PG&E states that scholarship winners receive scholarships of up to $20,000 with program finalists receive $2,000 towards their studies.

historical average 2016-2020 which accounts for labor escalation results in an expense forecast of $15.1 million, which is higher than PG&E's requested forecast of $14.447 million, the Commission finds reasonable the lower forecast for A&G Salaries for HR Service Delivery and Inclusion, as presented by PG&E. Accordingly, the Commission adopts a 2023 forecast for A&G Salaries in HR Service Delivery and Inclusion of $14.447 million.

Concerning Outside Services Utility (also referred to as contracts) within HR Service Delivery and Inclusion, the Commission finds reasonable Cal Advocates' recommendation to use recent historical data of a four-year average (2017-2020) for Outside Services Utility because costs in 2016 were significantly higher than costs in following years, which suggests that 2016 costs were an outlier. The Commission also finds reasonable PG&E's recommendation to include labor escalation into this forecast, which is contrary to Cal Advocates' recommendation. However, because a four-year average (2017-2020) forecast methodology which also accounts for labor escalation for 2023 results in an Outside Services Utility forecast of $8.1 million, an amount higher than both PG&E's forecast of $5.462 million and Cal Advocates' forecast of $4.3 million, the Commission find reasonable the lower recommended expense forecast that includes labor escalation of $5.462 million. Accordingly, the Commission adopts a 2023 department expense forecast for Outside Services Utility within HR Service Delivery and Inclusion of $5.462 million.

Regarding the companywide expense forecast within HR Service Delivery and Inclusion, PG&E's expense forecast for Workforce Transition-Severance is $14.26 million and Cal Advocates recommends $6.56 million based on a forecast methodology which omits an anomalous year.[2198] Cal Advocates recommended forecast represents an approximately 54% reduction (reduction of $7.708 million) to PG&E's forecast.[2199] While PG&E correctly states that the Commission has relied on a five-year historical average in the past regarding this cost, the Commission finds Cal Advocates' forecast reasonable based on recent historical data of a four-year average (2017-2020) because, as stated by Cal Advocates, PG&E has significant discretion when implementing layoffs to pay severance and to determine the amount of severance. As a result, even though the Commission does not always remove anomalous years, which in this instance is 2016-2017, the Commission finds it reasonable to remove this period because this specific cost, severance, is largely within PG&E's control. Accordingly, the Commission adopts a 2023 expense forecast for Workforce Transition-Severance of $6.56 million within companywide expense for HR Service Delivery and Inclusion.

For Workforce Transition–Outplacement Assistance, PG&E's forecast for this companywide expense is $386,000, while Cal Advocates recommends $78,000 (a reduction of $308,000 or approximately 75%).[2200] For the same reasons set forth above regarding Workforce Transition-Severance, Commission finds it reasonable to remove from the forecasting methodology the extreme fluctuation reflected in 2016-2017 and instead rely on the three-year trend for Workforce Transition- Outplacement Assistance, as presented in years 2018-2020. Accordingly, the Commission adopts Cal Advocates' recommended expense

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[2198] PG&E Opening Brief at 728.

[2199] CALPA Ex-11 at 14; PG&E Opening Brief at 728.

[2200] PG&E Opening Brief at 728.

forecast of $78,000 for Workforce Transition-Outplacement Assistance within companywide expense for HR Service Delivery and Inclusion.

For Workforce Transition-Tuition Refund, PG&E states that it reimburses up to $8,000 a year on tuition from a program-approved accredited school as a companywide expense.[2201] PG&E also explains that it has used a third-party vendor to administer Tuition Refund.[2202] With respect to Tuition Refund, the Commission finds that employee participation in Tuition Assistance was significantly lower in 2019-2020, likely due to PG&E's filing for bankruptcy, an event that is unlikely to recur during the 2023-2026 period. The Commission further finds that PG&E's forecasted participation in the program administered under Tuition Refund for 2023 is similar to the 2017-2018 period, the years before the bankruptcy. PG&E's forecast is based on a five-year average of cost per participant, multiplied by the expected participation rate for 2023. For the companywide expense of Workforce Transition-Tuition Refund within HR Service Delivery and Inclusion, the Commission finds reasonable PG&E's methodology, which accounts for forecasted participation in 2023 based on a five-year average multiplied by five-year average cost per participant because the years 2019-2020 were likely significantly lower due to bankruptcy, an anomalous event. For this reason, the Commission does not adopt Cal Advocates recommended forecast of $2.982 million ($0.910 million lower than PG&E's) based on a five-year average of historical costs (2016-2020), which would reflect the significantly lower costs in 2019-2020 which likely resulted from the

[2201] PG&E Opening Brief at 730.

[2202] PG&E Opening Brief at 730.

bankruptcy. Accordingly, for Workforce Transition-Tuition Refund, the Commission adopts a 2023 expense forecast of $3.9 million.

8.3. Short Term Incentive Plan, Non-Qualified Retirement, Total Rewards and Labor Escalation

PG&E's 2023 forecast for Human Resources includes several "employee incentive programs," "benefit programs," and labor escalation, including, the following: (1) Short-Term Incentive Plan (also referred to as STIP), (2) certain aspects of PG&E's Non-Qualified Retirement programs, (3) PG&E's Rewards and Recognition Program, and (4) labor escalation.[2203] In addition, labor expenses are included across most Exhibits and forecasts presented by PG&E. A chart illustrating the above programs and the related recorded actual costs for 2020 and forecasts for 2021, 2022 and 2023 is below.

[2203] These topics are presented in PG&E Ex-08, Ch. 4. Other forecasts related to compensation are addressed in PG&E Ex-08, Ch. 2 and Ch. 3.

TABLE 4-4
COMPENSATION – COMPANYWIDE EXPENSES
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2016	2017	2018	2019	2020	2021	2022	2023
		Recorded Adjusted						Forecast	
1	Non-Officer STIP								
2	Utility STIP	$146,799	$151,764	–	$196,059	$134,002	$207,776	$216,739	$224,702
3	PG&E Corporation and PSP2	256	430	–	250	145	106	108	110
4	Total Non-Officer STIP	$147,055	$152,195	–	$196,309	$134,147	$207,882	$216,847	$224,812
5	Officer STIP								
6	Utility STIP	$8,160	$7,631	–	$4,959	$4,048	$6,747	$6,968	$7,196
7	PG&E Corporation and PSP2	3,680	2,479	–	379	411	531	541	553
8	Total Officer STIP	$11,840	$10,110	–	$5,336	$4,459	$7,278	$7,278	$7,750
9	Total STIP	$158,896	$162,305	–	$201,647	$138,606	$215,160	$224,356	$232,562
10	Non-Qualified Retirement								
11	Utility SERP	$964	$908	$879	$2,708	$829	$829	$829	$829
12	PG&E Corporation SERP	1,418	1,696	1,953	1,961	2,004	2,032	2,070	2,118
13	Total SERP	$2,382	$2,604	$2,832	$4,669	$2,832	$2,860	$2,899	$2,947
14	Supplemental Retirement Savings Plan (SRSP and DC-ESRP)								
15	Utility SRSP/DC-ESRP	$1,053	$1,160	$1,313	$1,080	$650	$669	$691	$714
16	PG&E Corporation SRSP/DC-ESRP	130	241	10	84	35	35	36	37
17	Total SRSP and DC-ESRP	$1,183	$1.401	$1.323	$1,164	$684	$705	$727	$751
18	Total Non-Qualified Retirement	$3,565	$4,004	$4,155	$5,832	$3,517	$3,565	$3,626	$3,697
19	Total Compensation Companywide Exp	$162,461	$166,310	$4,155	$207,479	$142,123	$218,725	$227,982	$236,259

As illustrated by the above chart, PG&E requests the Commission to approve a number of different incentive and benefits programs for its 2023 forecasts as part of PG&E's overall compensation packages with Human Resources -Compensation.[2204] PG&E's forecast includes costs associated with two affiliates, PG&E Corporation and PG&E Support Services II.[2205] PG&E presents a 2023 expense forecast of approximately $236 million for the following "at-risk"[2206] components of its compensation packages in Ex. 8, Ch. 4:

2204 PG&E Opening Brief at 736.

2205 PG&E Ex-08 at 4-26.

2206 PG&E Ex-08 at 4-17, stating that an "at-risk" component of compensation is a commonly-accepted component of a competitive total compensation package and is conditioned on performance on important objectives, such as safety. These "at-risk" components are within managerial discretion.

(1) Short-Term Incentive Plan (also referred to as STIP), (2) Non-Qualified Retirement programs, and (3) the Rewards and Recognition Program. Each of these "at-risk" components are separately addressed below.

8.3.1. Short-Term Incentive Plan

Regarding Short-Term Incentive Plan, PG&E states that an "at-risk incentive pay component like STIP is a prevalent, commonly accepted compensation practice that is a valued component of a competitive compensation package for professional employees."[2207] PG&E's 2023 total STIP companywide expense forecast is $232.6 million ($231.9 million for PG&E and $863,000 for PG&E Corporation and PG&E Corporation Support Services II).[2208] PG&E's total 2020 recorded adjusted is $138.606 million.[2209] PG&E states that the $94.0 million increase over the 2020 recorded adjusted of $138.606 million is primarily attributable to labor escalation, changes in headcount, and the below-target 2020 STIP payment.[2210] PG&E describes its Short Term Incentive Plan as a program with metrics reviewed and approved each calendar year by members of the PG&E Corporation Board of Directors to provide eligible employees the opportunity to earn annual cash payments based the PG&E's achievements, relative to specified performance goals.[2211] PG&E states that both shareholders and customers benefit from the objectives of STIP, which include "striving to operate a safe, reliable, financially-healthy company."[2212] According to PG&E,

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[2207] PG&E Opening Brief at 736.

[2208] PG&E Ex-08 at 4-10; PG&E Opening Brief at 731.

[2209] PG&E Ex-08 at 4-26.

[2210] PG&E Opening Brief at 734.

[2211] PG&E Ex-08 at 4-11.

[2212] PG&E Ex-08 at 4-18.

recipients of STIP are primarily PG&E's salaried employees with "supervisory or other leadership responsibilities."[2213] PG&E's 2023 forecast consists of four separate categories: (1) Non-Officer Utility at $224.702 million, (2) Non-Officer PG&E Corporation and Affiliates at $0.110 million, (3) Non-SEC 3b-7 Officer Utility[2214] at $7.196 million, and (4) Non-SEC 3b-7 Officer Affiliates at $0.553 million.[2215] PG&E states STIP is a reasonable cost of service and the Commission should adopt PG&E's forecast as presented.[2216] PG&E clarifies it does not seek recovery in this GRC of approximately $102.7 million in compensation provided to "Utility and Corporate Officers and other higher-level management employees."[2217] Effective January 1, 2019, an amendment to Pub. Util. Code Section 706 prohibits utilities to recover from ratepayers the annual salaries, bonuses, benefits and other consideration paid to officers. These must instead be funded by their shareholders.

Cal Advocates recommends a total 2023 STIP forecast of $87.212 million, which is significantly lower than PG&E's request of $232.561 million.[2218] Cal Advocates states its forecast is based upon no ratepayer funding for the

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[2213] PG&E Ex-08 at 4-11.

[2214] The term "Officer" means those employees of the investor-owned utilities in positions with titles of Vice President or above, per Rule 240.3b-7 of the Securities Exchange Act.

[2215] PG&E Ex-08 at 4-15; PG&E Ex-08 at 4-26. PG&E Ex-08 at 4-20, stating that DC-ESRP is Corporation Defined Contribution Executive Supplemental Retirement Plan.

[2216] PG&E Opening Brief at 734-736.

[2217] PG&E Opening Brief at 734; PG&E Ex-08 at 4-6, stating: "PG&E is not seeking recovery in this GRC of approximately $102.7 million in compensation provided to Utility and Corporate Officers and other higher-level management employees. This includes approximately: (1) $93.7 million in long-term incentives for all executive and eligible non-executive employees; (2) $3.7 million in executive STIP target payments for the SEC 3b-7 Officers; and (3) approximately $5.3 million of base salary and benefits for SEC 3b-7 15 Officers." (fn. omitted.)

[2218] CALPA Ex-11 at 18.

"financial goals metric" and, in addition, a shared ratepayer/shareholder funding for the remaining metrics. Cal Advocates states that PG&E's 2023 forecast is an increase of approximately 67.79% compared to 2020 recorded adjusted costs of $138.606 million.[2219] Cal Advocates notes that, in the past, the Commission has expressed concern about the rapid growth in discretionary STIP costs and the fact that STIP funds are often distributed in a way that favors executives and managers over other lower ranked employees.[2220] TURN recommends a 2023 STIP forecasts of $86.970 million (PG&E Utility) plus $0.249 million (PG&E Corporation and affiliate), which TURN states represents a reduction of $144.950 million and $0.415 million, respectively.[2221] TURN recommends a disallowance of 100% of the STIP financial incentive forecast and a 50/50 split between ratepayers and shareholders for the remaining incentives.[2222] PG&E responds that the Commission should disregard Cal Advocates' and TURN's proposed reductions in PG&E's 2023 STIP forecast and other compensation components.[2223] In support of its position, PG&E states STIP is a commonly accepted part of a market-based compensation program, and a reasonable cost of service and significant "disallowance" is inconsistent with Commission precedents and would produce nonsensical results.[2224]

2219 CALPA Ex-11, Table 11-1 at 18-19.

2220 CALPA Ex-11, Table 11-1 at 21-24

2221 TURN Ex-16 (Rebuttal) at 1-10.

2222 TURN Ex-16 (Rebuttal) at 1-10.

2223 PG&E Reply Brief at 5-8.

2224 PG&E Reply Brief at 5-8, *citing to* D.19-09-051 (Sempra GRC) at 541-42; D.21-08-036, *Decision on Test Year 2021 General Rate Case for Southern California Edison Company* (August 19, 2021) at 433.

As set forth above, PG&E's 2023 expense forecast of $232.561 million for the total STIP is a $94 million (67.79%) increase from the 2020 recorded cost of $138.606 million. Cal Advocates proposes $87.212 million. TURN proposes $87.219 million. The Commission takes seriously Cal Advocates' questions concerning the validity of PG&E's position that a strong connection exists between STIP incentives of approximately $232.561 million annually and enhancement of PG&E's safety culture. The Commission agrees, as stated by Cal Advocates, that safety must be a core value of PG&E's employees, as a fundamental part of every employee's basic job duties and embedded in utility culture, "not something that needs to be purchased by ratepayers every year."[2225] Cal Advocates recommends that the Commission remove the STIP financial metric "Earnings from Operations" from ratepayer funding and adopt an equal sharing of the remaining costs between ratepayers and shareholders. Cal Advocates states that the Commission has consistently removed the incentive costs that are tied to utility financial performance.[2226]

PG&E fails to carry its burden of proof that a 67.79% increase for this "at risk" incentive – which stands as a core value and basic job requirement - is reasonable, especially when customers face unprecedented rate increases and PG&E's Total Compensation Study concludes compensation is competitive at 8.9% of the market. Contrary to proposals by TURN and Cal Advocates, the Commission finds that no need currently exists to manage the specific STIP metrics or percentages in this proceeding. In addition, while the Commission is not persuaded by proposals from Cal Advocates and TURN to remove certain

[2225] CALPA Ex-11 at 27.

[2226] Cal Advocates Opening Brief at 386, citing to D.21-08-036, Decision on Test Year 2021 General Rate Case for Southern California Edison Company (August 19, 2021).

STIP amounts solely because an amount is tied to a financial metric, the Commission finds it reasonable to disallow ratepayer funding for the "financial goals metric" based on past precedent. Accordingly, the Commission adopts an expense forecast for 2023 of $87.212 million for STIP within Human Resources Compensation.

8.3.2. Non-Qualified Retirement Programs

Regarding PG&E's non-qualified retirement programs, PG&E presents a 2023 companywide expense forecast that includes three components: (1) the Supplemental Executive Retirement Plans (SERP), (2) the Supplemental Retirement Savings Plan (SRSP), and (3) DC-ESRP.[2227] Tax-qualified Retirement Plan (pension) is addressed separately. PG&E's forecasted expenses are attributable to Non-Officers and non-SEC 3b-7 Officers.[2228]

Regarding the Supplemental Executive Retirement Plans (SERP), PG&E states that it is for highly-paid management employees, subject to federal compensation and contribution limits in the retirement plans offered to other PG&E employees.[2229] PG&E's 2023 forecast for non-qualified pension plans for former employees and future benefits for current non-Officer and non-SEC 3b-7 Officer employees is $3.7 million, a $181,000 (5.2%) increase over the equivalent recorded adjusted 2020 costs.[2230] PG&E's 2020 recorded costs are $14.882 million, which PG&E explains it significantly reduced to $2.947 million for its 2023 forecast based on Commission guidance in a prior GRC proceeding,

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[2227] PG&E Ex-08 at 4-18 and 4-26.

[2228] All pay-as-you-go administrative and tax-qualified pension and retirement excess expenses are included in PG&E Ex-08, Ch. 5, Employee Benefits.

[2229] Cal Advocates Opening Brief at 395.

[2230] PG&E Ex-08 at 4-18; Cal Advocates Opening Brief at 371.

D.14-08-032.[2231] PG&E's SERP 2023 expense forecast is $2.947 million, which is a $115,000 increase over 2020 recorded adjusted costs of $2.832 million (which PG&E also reduces).[2232]

Regarding the Supplemental Retirement Savings Plan (SRSP), PG&E states it provides matching employer contribution benefits to eligible employees based on the same benefit formula as the tax-qualified Retirement Savings Plan (RSP). These benefits are provided in the SRSP when PG&E is unable to make equivalent contributions to the qualified plan because of limitations imposed by law.[2233] The other non-qualified defined contribution plan, DC-ESRP,[2234] where participants receive contribution benefits are based on a percentage of salary and STIP payments.[2235]

Regarding the Supplemental Retirement Savings Plan (also referred to as "SRSP/DC-ESRP"), PG&E's total 2023 forecast is $751,000 which is a $66,000 increase over the 2020 recorded adjusted amount of $684,000.[2236] PG&E's SRSP/DC-ESRP benefits are non-qualified defined contribution plans for employees.

[2231] PG&E Opening Brief at 749, *citing to* D.14-08-032 at 533 and at 749 (fn. 3198) PG&E states "In PG&E's 2014 GRC decision (PG&E's last litigated GRC) the Commission adopted 50% of PG&E's forecast for the SERP portion of the Non-Qualified Retirement plans.

[2232] PG&E Ex-08 at 4-19 and 4-26; PG&E Opening Brief at 750, stating PG&E's 2023 forecast is $829,000 and PG&E Corporation's forecast is $2.118 million.

[2233] PG&E Ex-08 at 4-20.

[2234] PG&E Opening Brief at 749; PG&E Ex-08 at 4-20, stating that "DC-ESRP provides benefits to Officers who are appointed on or after January 1, 2013. For these participants, this new retirement plan replaces the SERP (i.e., participants in the DC-ESRP are ineligible for the SERP)."

[2235] PG&E Ex-08 at 4-20.

[2236] PG&E Ex-08 at 4-21 and 4-26.

Cal Advocates recommends a 2023 forecast for PG&E's Non-Qualified Retirement of $1.850 million, compared to PG&E's 2023 forecast of $3.697 million.[2237] PG&E's 2020 recorded adjusted cost is $3.517 million.[2238] No data is presented on forecasted costs for 2021 and 2022. In support of its lower recommendation, Cal Advocates states that ratepayers should not bear all cost of these supplemental benefits programs and suggests that these programs "serve to further enhance benefits to already highly compensated employees."[2239] Cal Advocates states it consistently advocates for equal sharing of SERP, DC-ESRP, and SRSP expense and suggests that Commission agreed, in part, with Cal Advocates' position in D.14-08-032, PG&E's last fully litigated GRC, when the Commission authorized rate recovery for 50% of PG&E's SERP and DC-ESRP.[2240] Cal Advocates further states that it considers PG&E's forecast unreliable and the calculations "convoluted."[2241] Regarding SRSP/DC-ESRP, PG&E's SERP 2023 forecast is $2.947 million, which is a $115,000 increase over 2020 recorded adjusted costs of $2.832 million. PG&E's total Supplemental Retirement Savings Plan (SRSP/DC-ESRP) 2023 forecast is $751,000 which is a $66,000 increase over the 2020 recorded adjusted amount of $684,000.

Based on the Commission's review of the record at this time when ratepayers face unprecedent rate increases together with TURN's compelling argument that these programs should be forecasted at $0 to reflect the absence of ratepayer benefit, the Commission finds that PG&E has failed to carry its burden

[2237] Cal Advocates Opening Brief at 395.

[2238] Cal Advocates Opening at 395.

[2239] CALPA Ex-11 at 29.

[2240] CALPA Ex-11 at 29.

[2241] CALPA Ex-11 at 29.

of proof that any increases in these "at-risk" components of compensation are reasonable over the 2020 recorded adjusted amount of $2.832 million. Accordingly, the Commission adopts a SERP 2023 expense forecast of $2.832 million and SRSP/DC-ESRP 2023 expense forecast of $684,000 within Human Resources - Compensation.

8.3.3. Reward and Recognition Program

PG&E states that its Reward and Recognition Program provides PG&E's "leaders" with an opportunity to provide recognition to employees who have gone above their normal job responsibilities.[2242] PG&E explains that these costs are a companywide expense and are recorded in the cost center for the employee receiving the compensation, not separately within the areas addressed in Ch. 4 of Ex-08.[2243] Under this program, PG&E states that it may provide "cash payments, gift cards or non-monetary items" to its employees.[2244] PG&E does not explain what constitutes a "non-monetary item." PG&E describes this program is an economical way for PG&E to "recognize and encourage employees to work safely, go above and beyond to achieve results and encourage innovation."[2245] PG&E's forecast for 2023 is $18.6 million (recorded 2020 costs are $18.9 million).[2246] PG&E's 2023 forecast is an average of 2018-2020 recorded plus labor escalation.[2247] PG&E acknowledges that the cost of PG&E's program might be higher than other

[2242] PG&E Ex-08 at 4-21.

[2243] PG&E Ex-08 at 4-22.

[2244] PG&E Ex-08 at 4-21.

[2245] PG&E Ex-08 at 4-21.

[2246] PG&E Ex-08 at 4-21.

[2247] PG&E Ex-08 at 4-21.

California utilities because PG&E has significantly more employees than other California utilities.[2248]

Regarding PG&E's Rewards and Recognition Program, Cal Advocates recommends a 2023 forecast of $0 to reflect zero ratepayer funding because PG&E's compensation is above market and PG&E's forecast is at a significantly higher amount than the other California utilities.[2249] Cal Advocates presents no adjustment to the forecasts presented in PG&E Ex-08, Ch. 4 to reflect this recommendation of $0 because the costs related to the Rewards and Recognition Program are recorded in the cost center for the employee receiving the compensation and are not separately forecasted.[2250]

With regards to the Rewards and Recognition Program, the Commission finds that PG&E failed to carry its burden of proof that it is reasonable for ratepayers to pay $18.6 million a year for purposes of employee recognition in cash payments, gift cards, and other non-monetary items (not specified) to PG&E employees at a time when customers are facing unpreceded rate increases. PG&E's compensation is competitive, and parties present evidence suggesting that PG&E compensation is higher than the other California utilities. PG&E employees deserve recognition for their work and for going beyond a supervisor's expectations, but the Commission finds it unreasonable for that recognition to cost ratepayers $18.6 million in cash and gift cards annually. PG&E's recognition of employee achievements can take other forms, such as a promotion or a future raise, without ratepayers bearing an additional $18 million annually for cash and gift cards. Accordingly, the Commission adopts

[2248] PG&E Ex-21 (Rebuttal) at 4-35.

[2249] CALPA Ex-11 at 31-32.

[2250] CALPA Ex-11 at 31-32.

Cal Advocates' recommendation for a 2023 expense forecast of $0 for PG&E's Rewards and Recognition Programs.

8.3.4. Labor Escalation

The last component of compensation presented in PG&E's Ex-08, Ch. 4 is labor escalation for the 2023-2026 period.[2251] PG&E explains that it monitors wage escalation in the market and increases its employees' base pay annually as necessary through General Wage Increases (GWI) for represented employees (also referred to as bargaining unit employees) and merit increases for non-represented employees.[2252] For represented employees, labor escalation is based on contract agreements. [2253] PG&E's proposed average labor escalation for all employees is 3.46% for 2023 to 2026. Below is a summary of GWI and market-based wage increases for 2021 and forecast through 2026.[2254]

2021-2026 Wage Increases

Line No.	Employee Category	2021	2022	2023-2026
1	IBEW Represented Clerical Employees	3.00%	3.75%	3.75%
2	IBEW Represented Physical Employee	3.00%	3.75%	3.75%
3	ESC Represented Employees	3.00%	3.75%	3.75%
4	SEIU Represented Employees	3.00%	3.00%	3.00%
5	Non-Represented Employees	3.07%	3.07%	3.07%
6	Average Labor Escalation – All Employees	3.03%	3.46%	3.46%
7	Average Labor Escalation – Operating Units	3.02%	3.52%	3.52%
8	Average Labor Escalation – A&G	3.06%	3.28%	3.28%

PG&E further states that its labor adjustments use escalation rates described above to increase 2023 adopted operating unit (3.52%) and A&G

[2251] PG&E Ex-08 at 4-22 to 4-24.

[2252] PG&E Ex-08 at 4-22 to 4-24.

[2253] PG&E Ex-08 at 4-22 to 4-24.

[2254] PG&E Ex-08 at 4-22.

organization (3.28%) labor expenses in 2024, 2025, and 2026.[2255] Labor-related expenses subject to these adjustments also include payroll taxes and wage-related benefits (FERC Account 926), excluding pension and medical plan costs.[2256] PG&E describes its proposed labor escalation rates as blended rates that reflect the wage escalation for represented and non-represented employees.[2257] PG&E states that contracts with the International Brotherhood of Electrical Workers (IBEW) Physical and Clerical Bargaining Units and the Engineers and Scientists of California (ESC) Bargaining Unit set wage levels for represented employees through the end of 2025 and a contract with the Service Employees International Union (SEIU) Bargaining Unit sets wage levels through the end of 2021.[2258] Those agreements provide a 3.75% for IBEW and ESC represented employees, and 3.0% for SEIU. In short, non-represented employees - a 3.52% Weighted Average (WAVG) wage increase for non-represented employees in the operating Lines of Business (LOB) and a 3.28% for the A&G Line of Business, and an overall company WAVG of 3.46%.[2259]

TURN states that the Commission should adopt labor escalation at CPI-U or CPI-U plus 50 basis points.[2260] TURN states labor escalations are lower than those proposed by PG&E, with CPI-U and CPI-U plus 50 basis point averages over 2022-2026 are 2.50% and 3.00% compared with PG&E's 3.46%. In response, CUE states that TURN's labor escalation rate is unreasonably low and

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[2255] PG&E Ex-11 at 2-5, *citing to* PG&E Ex-08 at WP 4-22.

[2256] PG&E Ex-11 at 2-5, *citing to* PG&E Ex-08 at WP 4-22.

[2257] PG&E Ex-11 at 2-5, *citing to* PG&E Ex-08 at WP 4-22.

[2258] PG&E Ex-11 at 2-5, *citing to* PG&E Ex-08 at WP 4-22.

[2259] PG&E Ex-08 at 4-24 to 4-25.

[2260] TURN Ex-20 at 11.

recommends PG&E's estimate of 3.46% on the basis that the Commission has historically not tied labor escalation to CPI.[2261] CUE further states that recently the Commission approved labor escalation of 3.75% for IBEW employees in D.20-05-53.[2262] CUE states that this labor escalation, which is part of a labor contract, of 3.75% is not optional for PG&E.[2263]

To summarize, PG&E proposes a labor escalation of 3.46% for 2023 to 2026. TURN suggests labor escalations based on the CPI-U and CPI-U plus 50 basis point averages over 2022-2026, which are 2.50% and 3.00% compared with PG&E's 3.46%. The Commission finds that TURN's proposal to reduce PTY labor escalation based on the CPI does not appropriately reflect PG&E's labor market. TURN's suggested labor escalations based on CPU are much lower than those proposed by PG&E. The CPI-U and CPI-U plus 50 basis point average are 2.5% and 3%, respectively, over 2022-2026. In last litigated GRC, PG&E's 2014 rate case, the Commission declined to adopt Cal Advocates' recommendation to use CPI as the basis for PG&E's cost escalation.[2264] The CPI is an index that measures changes in consumer prices and, in this proceeding, may not be the best proxy for a wage index. As noted above, CUE supports PG&E's labor escalation rate. PG&E's proposed labor escalation rate is 3.46%. The Commission finds that PG&E's proposal is consistent with historical practice and is based, in part, on authorized escalations that cannot be avoided by PG&E due to labor agreements. Accordingly, the Commission adopts PG&E's request to escalate labor expenses

[2261] CUE Opening Brief at 36, *citing to* D.14-08-032 at 526; PG&E-24-E at 1-15 to 1-16; CUE Ex-02 at 20.

[2262] CUE Ex-02 at 20.

[2263] CUE Ex-02 at 19-20.

[2264] D.14-08-032, *Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2014-2016* (August 14, 2014) at 526-527, 711.

by 3.46%, including the below noted General Wage Increases and market-based wage increases for 2021 and forecast through 2026.

Table 4-2: [2265]
2021-2026 Wage Increases

Line No.	Employee Category	2021	2022	2023-2026
1	IBEW Represented Clerical Employees	3.00%	3.75%	3.75%
2	IBEW Represented Physical Employee	3.00%	3.75%	3.75%
3	ESC Represented Employees	3.00%	3.75%	3.75%
4	SEIU Represented Employees	3.00%	3.00%	3.00%
5	Non-Represented Employees	3.07%	3.07%	3.07%
6	Average Labor Escalation – All Employees	3.03%	3.46%	3.46%
7	Average Labor Escalation – Operating Units	3.02%	3.52%	3.52%
8	Average Labor Escalation – A&G	3.05%	3.28%	3.28%

8.4. Benefits Department and Employee Benefits

This Section addresses PG&E's 2023 expense forecast for Benefits Department's expenses of $2.3 million, a $1.0 million increase compared to 2020 recorded adjusted expense of $1.356 million.[2266] This Section also addresses PG&E's 2023 expense forecast for employee benefits, a companywide expense of $690.1 million.[2267] This is a 29% increase over 2020 recorded adjusted costs of $535.0 million (which is $19 million less than the 2019 recorded adjusted costs of $554 million.[2268]

PG&E's forecasted employee benefits include (1) Health and Welfare (Medical, Dental, Vision, Active Employee Life Insurance), (2) Post-Retirement (Retirement Savings Plan (401K), Post-Retirement Medical and Post-Life trust

[2265] The table referred to as "Table 4-2 2021-2026 Wage Increases" is reproduced from PG&E Ex-08.

[2266] PG&E Opening Brief at 753; PG&E Ex-08, Ch. 5.

[2267] PG&E Ex-08 at 5-43. PG&E's 2023 forecast includes $256 million for PG&E Corporation and PG&E Corporation Support Services II.

[2268] PG&E Opening Brief at 758; PG&E Ex-08 at 5-5 to 5-8 and 5-43.

contributions, Pay as You Go (PAYG) Medical and Life Insurance benefits), and (3) other benefits (relocation program, emergency dependent care program, service awards, ad reimbursement for adoption cost.[2269] Costs attributable to PG&E Corporation and PG&E Corporation Support Services II (Affiliated Entities) employees who participate in Company-sponsored benefit plans are shown separately in PG&E Ex-08, Ch. 5, Tables 5-1 to 5-4.

PG&E's forecast for certain Active Employee Health and Welfare Benefits, Post-Retirement Benefits, and Other Benefit Programs are uncontested.[2270]

8.4.1. Benefits Department

PG&E states that its 2023 expense forecast for Benefits Department is $2.3 million, a $1.0 million increase compared to 2020 recorded adjusted of $1.356 million.[2271] PG&E's notes that its 2019 recorded expense of $1.961 million is higher than 2020.[2272] PG&E's Benefit Department 2023 expense forecast includes the following categories: (1) Salaries of $1.997 million, (2) Office Supplies and Expense of $63,000, (3) Outside Services Utility of $224,000, and (4) Outside Services – Corp. of $0.[2273]

Regarding Salaries within Benefits Department, PG&E states that the increase reflects labor escalation and the staffing cost increase to reflect

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[2269] PG&E Ex-08 at 5-2, stating: "Pursuant to California Public Utilities Commission (CPUC or Commission) Resolution E-4963 (December 14, 2018), the 2023 forecast does not include benefits for the utility's Securities and Exchange Commission (SEC) Rule 240.3b-7 Officers. PG&E has also voluntarily excluded from its 2023 forecast to the salary and benefits of the PG&E Corporation's SEC Rule 240.3b-7 Officers although not required by the Resolution."

[2270] PG&E Opening Brief at 758; PG&E Ex-08 at 5-5 to 5-8. PG&E states that, pursuant to Resolution E-4963 (December 14, 2018), the 2023 forecast does not include benefits for the utility's Securities and Exchange Commission Rule 240.3b-7 Officers.

[2271] PG&E Opening Brief at 753; PG&E Ex-08, Ch. 5.

[2272] PG&E Opening Brief at 753; PG&E Ex-08, Ch. 5.

[2273] PG&E Ex-08 at 5-43.

employees hired over the course of 2020.[2274] PG&E states that Cal Advocates' use of a five-year average of nominal dollars fails to account for labor escalation and the staffing cost increase to reflect employees hired in 2020. Using the average of base year dollars and escalated (labor escalation) to 2023, PG&E states that a five-year average forecast methodology would result in a Salaries forecast of $2.046 million, which is higher than the $1.997 million for Salaries included in PG&E's 2023 forecast.[2275]

Regarding Outside Services Utility within Benefits Department, PG&E states that the increase in Outside Services Utility reflects increases in costs associated with legally required notices and the movement of benefits related work for HR Service Delivery & Inclusion to the Benefits Department team.[2276] PG&E states that a three-year average forecast methodology, as recommended by Cal Advocates, should use the average of base year dollars and also include escalation, which would result in Outside Services Utility forecast of $124,000, which is higher than the $115,000 recommended by Cal Advocates.[2277]

Cal Advocates contests two components of PG&E's 2023 expense forecast for Benefits Department of $2.284 million, as follows: (1) Salaries, and (2) Outside Services Utility.[2278] Cal Advocates recommends $1.909 million.[2279]

[2274] PG&E Reply Brief at 575.

[2275] PG&E Ex-21 (Rebuttal) at 5-9; PG&E Reply Brief at 575.

[2276] PG&E Reply Brief at 575-576.

[2277] PG&E Ex-21 (Rebuttal) at 5-9 to 5-10.

[2278] Cal Advocates Opening Brief at 398.

[2279] Cal Advocates Opening Brief at 398.

Regarding Salaries, PG&E forecasts expense of $1.997 million in 2023 and Cal Advocates recommends $1.731 million.[2280] Cal Advocates states that PG&E's 2023 forecast for Salaries is an increase of approximately 67.11% above 2020 recorded adjusted expenses of $1.195 million. Cal Advocates notes fluctuations in the recorded Salaries and recommends reliance on five-year average of recorded costs.[2281]

Regarding Outside Services Utility, PG&E's 2023 expense forecast is $224,000, which Cal Advocates states is an increase of approximately 190.9%.[2282] Cal Advocates recommends a three-year average (2018-2020) of actual recorded costs for Outside Services Utility because the costs have trended downwards.[2283] Cal Advocates recommends $115 million based on this downward trend.[2284]

The Commission finds that Cal Advocates' reliance on a five-year average of nominal dollars for Salaries does not account for labor escalation and the staffing cost increases needed to reflect hires.[2285] The Commission agrees with PG&E that a five-year average forecast methodology with those added variables would result in higher Salaries than Cal Advocates' forecast.[2286] For these reasons, the Commission finds PG&E's expense forecast of $1.997 million reasonable for Salaries within Benefits Department because the forecast accounts

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[2280] Cal Advocates Opening Brief at 398.

[2281] Cal Advocates Opening Brief at 398.

[2282] Cal Advocates Opening Brief at 398.

[2283] Cal Advocates Opening Brief at 398-399.

[2284] Cal Advocates Opening Brief at 398.

[2285] Cal Advocates recommends a 2023 forecast of $1.909 million, which is a $375,000 reduction based on a five-year average for Salaries and a three-year average for Outside Services Utility.

[2286] PG&E proposes a 2023 forecast of $2.3 million for department cost for Benefits Department, which is a $1.0 million increase compared to 2020 recorded adjusted.

for staffing cost increases and labor escalation. Accordingly, the Commission adopts a 2023 expense forecast for Salaries of $1.997 million within Benefits Department.

Regarding Outside Services Utility, Cal Advocates states that PG&E's 2023 forecast of $224,000 represents an increase of approximately $190%, compared to the 2020 recorded adjusted costs of $77,000.[2287] Cal Advocates relies upon a three-year average (2018-2020) for Outside Services Utility because costs have trended downward to recommend a 2023 forecast of $115,000, a reduction of $109,000 to PG&E's 2023 forecast.[2288] The Commission finds PG&E's 2023 expense forecast for Outside Services Utility of $224,000 within Benefits Department reasonable because PG&E's cost increases are associated with additional legally required notices, escalation, and a five-year average of historical cost reflects the variability in costs over time. Accordingly, the Commission adopts 2023 expense forecast for Outside Services Utility of $224,000 within Benefits Department.

8.4.2. Health and Welfare Expense – Companywide Expense

Regarding the companywide expenses related to benefit packages under Health and Welfare, PG&E's 2023 expense forecast is $536.3 million, which includes forecasted expenses for PG&E Corporation and PG&E Corporation Support Services II.[2289] PG&E's 2020 recorded adjusted expense is $385.492 million.[2290] PG&E's forecast for company-wide Health and Welfare

[2287] CALPA Ex-11 at 35; PG&E Ex-08 at 5-43.

[2288] CALPA Ex-11 at 35.

[2289] PG&E Ex-08 at 5-39 (Table 5-1).

[2290] PG&E Ex-08 at 5-39 (Table 5-1).

benefits for both PG&E and affiliates includes the following five benefits programs: Medical Programs, Dental, Vision, Employee Health Care Contributions, and Group Life Insurance Benefits. PG&E states that, if it were to offer a less competitive benefits package, it could negatively impact PG&E's ability to attract and retain employees.[2291] PG&E states that its benefit plan continues to be based on improving the health (physical, financial, and emotional) and safety of its workforce, as well as the necessity to provide competitive compensation to attract and retain employees.[2292] PG&E states that for Medical Expense it is appropriate to use an "estimating methodology" that relies on forecasts provided by Mercer, an actuarial consulting firm experienced in forecasting medical cost trends specific to large employer-sponsored plans and which has knowledge of the Northern California medical provider marketplace, including PG&E's medical plans.[2293] PG&E's expense forecast for Health and Welfare includes a medical escalation rate forecast of 3.5% on average for 2024, 2025 and 2026.

Cal Advocates proposes a 2023 expense forecast of $401.6 million, which is a $134.2 million (approximately 25%) reduction to PG&E's Medical Program 2023 forecast of $536 million.[2294] Cal Advocates states that the Commission should adopted a reduced forecast in two areas, Medical Program and Dental.

Regarding Medical Program, Cal Advocates states that PG&E's request is an increase of approximately 36% over 2020 recorded adjusted expenses of

[2291] PG&E Ex-08 at 5-4.

[2292] PG&E Ex-08 at 5-5.

[2293] PG&E Opening Brief at 759-760.

[2294] Cal Advocates Opening Brief at 399.

$393 million.[2295] Cal Advocates states that from 2016 to 2019, PG&E's Medical Program costs trended upwards at an average 7.45% annual percentage but in 2020 expenses decreased 4.3% due to COVID-19.[2296] Cal Advocates describes PG&E 2023 forecast as "dramatic" and finds the actuarial analysis prepared by Mercer unpersuasive. Cal Advocates states that the actuarial expectation for 2023 does not reflect the trend in the historical data and the variability one might expect in Medical Program plus the modest forecast change in headcount does not adequately explain PG&E's forecast that is double the historical trend rate.[2297] For these reasons, Cal Advocates recommends the forecast for Medical Program use a five-year average of historic costs, which would result in a 2023 forecast of $401 million, compared to PG&E's 2023 forecast is $535 million.[2298]

With respect to Dental, Cal Advocates recommends a 2023 expense forecast of $30.466 million.[2299] PG&E requests a 2023 forecast of $37.780 million (2020 recorded adjusted is $26.7 million).[2300] Cal Advocates states that PG&E fails to explain why it is requesting an almost 40% increase over 2020 recorded adjusted amounts, when the Dental expense were already trending down before 2020.[2301] Cal Advocates states that historical costs trended down from 2017-2019 and fell significantly in 2020, perhaps due to the COVID-19.[2302] Cal Advocates

[2295] Cal Advocates Opening Brief at 399.

[2296] Cal Advocates Opening Brief at 399-400.

[2297] Cal Advocates Opening Brief at 399-400.

[2298] PG&E Ex-08 at Table 5-1; Cal Advocates Opening Brief at 399.

[2299] Cal Advocates Opening Brief at 402.

[2300] PG&E Ex-08 at Table 5-1.

[2301] PG&E Ex-08 at Table 5-1; Cal Advocates Opening Brief at 402.

[2302] Cal Advocates Opening Brief at 402.

recommends $30.466 million based on a five-year average (2016-2020) recorded costs.[2303] Cal Advocates states that this is reflective of the history of this benefit and reasonable given the historical variability of companywide expense of Dental.[2304] In response, PG&E states that including the reduced 2020 recorded spend in a five-year average without adjusting for the COVID-19 closures incorrectly assumes that these reductions will continue in the future.[2305]

The Commission finds that PG&E's Health and Welfare companywide expense forecast of $536 million for PG&E and affiliates for 2023 is an increase of approximately 36% compared to 2020 recorded adjusted costs of $385 million. Regarding Medical Program, the Commission agrees with Cal Advocates that PG&E's 2023 expense forecast presents a "dramatic" increase and finds PG&E fails to carry its burden of proving the reasonableness of its 2023 forecasted expense for Medical Program. While PG&E supports its recommendation stating that the Commission should not deviate from its longstanding practice of adopting medical costs forecasts based on actuarial analysis in favor of a five-year average recommend by Cal Advocates, PG&E provides little support of this long-standing practice. Moreover, the Commission finds the actuarial analysis of Mercer unpersuasive on this topic as Mercer inadequately explains why the 2023 forecast does not reflected the trends illustrated in the historical data and the variability one might expect in Medical Program when a modest change in headcount is forecasted. The Commission finds that PG&E's 2023 expense forecast is double the historical trend rate and PG&E does not adequately support this increase. Accordingly, the Commission adopts the

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[2303] PG&E Ex-08 at Table 5-1; Cal Advocates Opening Brief at 402.

[2304] Cal Advocates Opening Brief at 402.

[2305] PG&E Opening Brief at 763.

recommendation of Cal Advocates of a 2023 expense forecast of $401.6 million for Medical Program, which is a $134.2 million (approximately 25%) reduction of PG&E's 2023 forecast of $536 million. Regarding Dental, the Commission similarly finds that PG&E fails to carry its burden of proof that a 40% increase over 2020 recorded adjusted is reasonable. PG&E requests a 2023 expense forecast of $37.780 million (2020 recorded adjusted is $26.7 million). Accordingly, the Commission adopts Cal Advocates' recommendation for Dental based on a five-year average (2016-2020) recorded costs for a 2023 expense forecast of $30.466 million (approximately $7 million less than PG&E's 2023 forecast).

8.4.3. Post-Retirement Benefits - Companywide Expense

PG&E provides a expense forecast for Post-Retirement Benefits for PG&E and its affiliates, PG&E Corporation and PG&E Corporation Support Services II.[2306] PG&E's total 2023 forecast for Post-Retirement Benefits is $145.702 million with a 2020 recorded adjusted cost of $142.023 million.[2307] PG&E's Post-Retirement Benefits forecast covers Pension Administration (Pay as You Go-PAYG) (2023 forecast of $153 million and 2020 recorded adjusted of $90 million), Retirement Savings Plan (2023 forecast of $141.096 million and 2020 recorded adjusted of $119.450 million), Post-Retirement Medical (Pay As You Go-PAYG) (2023 forecast of $422 million and 2020 recorded adjusted of $118 million) Post-Retirement Life (PAYG) (2023 forecast of $3.293 million and 2020 recorded adjusted of $4.877 million), Retirement Excess Plan (2023 forecast of $736,000 and 2020 recorded adjusted of $678 million), Post-Retirement Life (Trust) (2023 forecast of $2 million and 2020 recorded adjusted of $3 million), and

[2306] PG&E Ex-08 at 5-18 and 5-40 to 5-41.

[2307] PG&E Ex-08 at 5-18 and 5-40 to 5-41.

Retirement Medical (Trust) (2023 forecast of $0 and 2020 recorded adjusted of $16.808 million). The Commission addresses below the two contested components of the companywide expense of Post-Retirement Benefits, (1) Retirement Savings Plan, and (2) Retirement Excess Plan.

PG&E explains that most of its forecast for rate recovery is for PG&E's employer match to employees 401k contributions and the contributions to tax-qualified trusts.[2308] This includes contributions to post-retirement medical and life insurance trusts.[2309] PG&E states that, in these tax-favored arrangements, PG&E receives a current tax benefit (passed on to customers) at the time it makes a contribution.[2310] PG&E states it is not requesting any cost recovery for the pension trust in this rate case proceeding, as those amounts have been separately provided for in D.09-09-020.[2311] Regarding Retirement Savings Plan, PG&E states that it is appropriate for the total cost of the Retirement Excess Plan to be included in rates because this amount of $736,000 is not for "already highly compensated executives" and is typically for "long service employees who have worked past the normal retirement age of 65 and whose benefit under the qualified pension plan is limited due to actuarial factors."[2312] Regarding Retirement Excess of $736,000, PG&E states it is appropriate for the cost of the Retirement Excess Plan to be included in rates and is a benefit for non-executive

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[2308] PG&E Ex-08 at 5-18 and 5-40 to 5-41.

[2309] PG&E Ex-08 at 5-18 and 5-40 to 5-41.

[2310] PG&E Ex-08 at 5-18 and 5-40 to 5-41.

[2311] PG&E Ex-08 at 5-18.

[2312] PG&E Ex-21 (Rebuttal) at 5-16 to 5-17.

employees (not executive level employees) whose pension from the qualified plan is limited based on IRS rules."[2313]

Cal Advocates recommends adjustments to two components of Post-Retirement Benefits, as follows: (1) Retirement Savings Plan, and (2) Retirement Excess Plan. Regarding Retirement Savings Plan, PG&E's request for the Retirement Savings Plan is $141.096 million and Cal Advocates' recommendation is $140.072 million.[2314] Cal Advocates' proposal starts with the average increase in recorded costs from 2016 through 2020, which is 5.45%.[2315] Cal Advocates applies this 5.45% trend rate to PG&E's 2020 recorded match of $119.450 million to obtain forecasts for 2021, 2022, and 2023.[2316] This results in a 2023 forecast for Retirement Savings Plan of $140.072 million.[2317] Regarding Retirement Excess Plan, PG&E's 2023 forecast is $736,000, and Cal Advocates recommends $359,000.[2318] Cal Advocates states that, while it has consistently recommended no ratepayer funding for Retirement Excess Plan on the basis that ratepayers should not fund benefits beyond the federal limits to enhance benefits to already highly compensated executives, Cal Advocates also recognizes that the Commission has found that ratepayers and shareholders should equally share this expense and cites to D.21-08-036, D.19-05-020, D.15-11-021, and D.14-08-032.[2319] Cal Advocates states that, taking the Commission's findings into

[2313] PG&E Ex-21 (Rebuttal) at 5-16 to 5-17.

[2314] Cal Advocates Opening Brief 402-403.

[2315] Cal Advocates Opening Brief 402-403.

[2316] Cal Advocates Opening Brief 402-403.

[2317] CALPA Ex-11 at 40-41.

[2318] Cal Advocates Opening Brief at 402-403.

[2319] CALPA Ex-11 at 41-43, *citing to* D.21-08-036 at 618; D.19-05-020 at 418; D.15-11-021 at 261; and D.14-08-032 at 535.

consideration, it recommends a 50% reduction to PG&E's 2023 Retirement Excess Plan forecast of $736,000 for a recommended forecast of $359,000, which is 50% reduction to PG&E's original forecast.[2320]

Regarding Retirement Savings Plan, the Commission finds that PG&E fails to carry its burden of proof regarding the reasonableness its 2023 requested forecast of $145.702 million as Cal Advocates raises persuasive arguments that PG&E's forecast is too high. Cal Advocates' argument includes a $1.4 million reduction to PG&E's forecast, based on the average increase in recorded costs from 2016 through 2020. The average increase is 5.45%, which, as applied to PG&E's 2020 recorded match of $119.450 million, results in a 2023 forecast for Retirement Savings Plan of $140.072 million. Accordingly, the Commission adopts a 2023 expense forecast of $140.072 million for Retirement Savings Plan, which is a companywide expense, within Post-Retirement Benefits.

Regarding Retirement Excess Plan, the Commission finds that PG&E did not carry its burden of proof as to the reasonableness of its requested 2023 expense forecast of $736,000 based on Cal Advocates' persuasive argument that supports relying on the Commission's recent decisions to limit the amount of this expense included in rates to 50% of the forecasted expense. Accordingly, the Commission adopts a 2023 expense forecast of $368,000 for Retirement Excess Plan, which is a companywide expense, within Post-Retirement Benefits.

8.4.4. Other Benefits – Companywide Expense

PG&E's 2023 expense forecast for Other Benefits, a companywide expense, is $8.120 million, compared to a 2020 recorded adjusted of $7.485 million.[2321]

[2320] Cal Advocates Opening Brief at 402-403; CALPA Ex-11 at 41-43; PG&E Ex-21 (Rebuttal) at 5-16.

[2321] PG&E Ex-08 at 5-42.

PG&E's Other Benefits refers to 2023 forecasts for a diverse set of services provided by PG&E, including (1) Relocation of $7.073 million (2020 recorded adjusted of $6.566 million), (2) Commuter Administration Service of $105,000 (2020 recorded adjusted of $42,000), (3) Family Support of $33,000 (2020 recorded adjusted is not provided; 2021 forecast is $36,000), Service Awards of $893,000 (2020 recorded adjusted of $876,000), and Adoption Reimbursement Awards of $17,000 (2020 recorded adjusted of $2,000).[2322] PG&E's forecast does not include any amounts for its affiliates, PG&E Corporation and PG&E Corporation Support Services II.[2323]

Cal Advocates recommends a total of $6.319 million for Other Benefits, compared to PG&E's 2023 forecast of $8.120 million.[2324] Cal Advocates recommends reductions to two components of PG&E's 2023 expense forecast for Other Benefits, as follows: (1) Relocation, and (2) Commuter Administration.[2325] Regarding Relocation, PG&E's 2023 forecast is $7.073 million based on a four-year average (2016-2019) cost per relocation.[2326] Cal Advocates recommends using a four-year average (2017-2020) which results in $5.323 million, a reduction of $1.750 million.[2327] Cal Advocates excludes 2016 ($11.3 million) because, according to Cal Advocates, this data reflects unexplained high relocation costs.[2328] In response, PG&E supports its forecast using a four-year average

[2322] PG&E Ex-08 at 5-42.

[2323] PG&E Ex-08 at 5-42.

[2324] Cal Advocates Opening Brief at 405.

[2325] Cal Advocates Opening Brief at 405.

[2326] PG&E Ex-08 at 5-42.

[2327] CALPA Ex-11 at 45-46; Cal Advocates Opening Brief at 405-406.

[2328] Cal Advocates Opening Brief at 406, stating that a third-party administers this program for PG&E.

(2016-2019) of costs per relocation request, and states that 2020 costs are not available.[2329] PG&E suggests that 2020 should be excluded as an atypical year for relocations due to COVID-19, an assertion that Cal Advocates found unlikely due to PG&E's data for 2020 and 2019.[2330] Regarding Commuter Transit Administration, PG&E's 2023 forecasts is $105,000 for Commuter Transit Administration and Cal Advocates recommends $53,000, a 50% reduction, to bring the 2023 forecast closer to the 2020 recorded actual of $42,000 and also recommends that this expense be shared with shareholders.[2331] This results in Cal Advocates' 2023 forecast of $53,000, a reduction of $52,000.[2332] In response, PG&E states that its 2023 forecasts of $105,000 for the Commuter Transit Administration is reasonable because it is based on the four-year average recorded cost (2016-2019), which appropriately excludes the non-typical 2020 transit year due to the COVID-19 shutdowns.[2333]

The Commission addresses the contested components of Other Benefits as follows. Regarding Relocation, which is a companywide expense under Other Benefits, the Commission finds that PG&E fails to carry its burden of proving the reasonableness of its reliance on the use of a four-year average (2016-2019) cost per relocation for its 2023 forecasts of $7.073 million as PG&E does not adequately explain why a five-year average, which would also include 2020, is not a more accurate picture.[2334] As employers continue to adjust to the changing

[2329] Cal Advocates Opening Brief at 406.

[2330] Cal Advocates Opening Brief at 406.

[2331] Cal Advocates Opening Brief at 405.

[2332] CALPA Ex-11 at 47; Cal Advocates Opening Brief at 405-407; PG&E Reply Brief at 582.

[2333] PG&E Ex-21 (Rebuttal) at 5-22 to 5-23; PG&E Reply Brief at 581.

[2334] PG&E Ex-08 at 5-42.

landscape of increased remote work, many variables will impact Relocation in 2023 and the experiences of 2020, which changed modern work location trends, are relevant to this forecast. Cal Advocates' use of a four-year average (2017-2020), which results in $5.323 million, a reduction of $1.750 million, is also not persuasive. Cal Advocates' recommendation to exclude 2016 ($11.3 million) because 2016 reflected unexplained high relocation costs is not persuasive.[2335] A five-year average would be the preferable outcome. However, because a five-year average forecast is not presented by any party, the Commission finds it reasonable to adopt a compromise position for Relocation under Other Benefits, by taking the average of the PG&E and the Cal Advocates forecast because an average would reflect in the 2023 forecast the five-year period (2016-2020), including the higher expense year in 2016 and the more recent year of changing trends in 2020. Accordingly, the Commission adopts a 2023 expense forecast of $6.2 million for Relocation, a companywide expense under Other Benefits.

Regarding Commuter Transit Administration, also a companywide expense under Other Benefits, Cal Advocates' recommendation is not persuasive because transit is a fundamental aspect of job performance and presents a relatively large expense for employees that typically use public transit or even a barrier for job performance. The Commission finds PG&E's forecast reasonable based on a four-year average of recorded costs (2016-2019), which appropriately excludes the 2020 transit year as non-typical due to COVID when most employees worked from home. Accordingly, the Commission adopts the 2023 expense forecast of $105,000 for the Commuter Transit Administration, a companywide expense within Other Benefits.

[2335] Cal Advocates Opening Brief at 406.

The Commission also addresses PG&E's 2023 expense forecast of $893,000 for Service Awards, a companywide expense within Other Benefits, which is based on the four-year average cost for the program with escalation.[2336] No parties contests this forecasted expense. PG&E supports including this expense in customer rates, stating "The Company expresses appreciation for these employees with a recognition award at each five-year service anniversary and at retirement. Employees select an item, such as an engraved belt buckle with years of service, from a collection of awards that vary based on years of service. Providing a token of appreciation for continuous service sends a signal" to employees of their important service to the public.[2337] PG&E states that the Commission reduced its forecast in the 2014 GRC by 50%.[2338] PG&E also points out that the Commission has approved full funding of similar programs for other California utilities stating that "In San Diego Gas and Electric Company and Southern California Gas Company's 2019 General Rate Case, the Commission authorized full funding for the program stating, '[w]e also have no objection to the funding request for Service Recognition and find that this benefit is a common benefit provided by companies to recognize employees for their length of service and loyalty to the job that they perform.'"[2339] The Commission finds that PG&E fails to carry its burden of proving that this expense is reasonable for customers to pay, especially when customers face unprecedented rate increases. Regarding similar funding requests recently approved by the Commission in

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[2336] PG&E Ex-08 at 5-31 to 5-32.

[2337] PG&E Ex-08 at 5-31 to 5-32.

[2338] PG&E Ex-08 at 5-31 to 5-32.

[2339] PG&E Ex-08 at 5-31 to 5-32, *citing to* D.19-09-051 at 554 regarding SDG&E and SoCalGas TY 2019 forecast for Service Recognition Awards of a total of approximately $450 thousand to recognize length of service and loyalty to job.

D.19-09-05, the requested amounts were less than the amount PG&E requests now. Within the context of the overall increase proposed by this rate case, the Commission does not find it reasonable for ratepayers to support the costs of small trinkets, such as engraved belt buckles, with a 2023 expense forecast of $893,000 based on PG&E's assertion such items promote the "interests of customers." PG&E has other programs for employee recognition with metrics that are more closely tied to customer interests. PG&E may continue this program but not at ratepayer expense for this rate case period, 2023-2026. Accordingly, the Commission adopts a 2023 expense forecast of $0 for Service Awards within Other Benefits.

8.5. PG&E Academy Department

PG&E's 2023 forecast for Human Resources in PG&E Ex-08 includes the PG&E Academy Department, which PG&E describes as part of the company that develops and trains new and existing employees on technical, safety, and other topics to help to maintain a skilled, safe, and qualified workforce.[2340] According to PG&E, PG&E Academy represents an example of how PG&E Human Resources directly supports the delivery of safe and reliable services to customers.[2341] PG&E states that PG&E Academy is recognized as "one of the top training organizations in the world" and has made a number of improvement in the recent years, including a heightened focus on contractors in two primary areas: (1) training contractors on tasks that are specific to how PG&E performs the work, and (2) auditing contractor training records.[2342] PG&E's forecast for

[2340] PG&E Ex-08 at 6-1; PG&E Ex-08, Ch. 6 provides cost and forecast information on the PG&E Academy.

[2341] PG&E Ex-08 at 6-1.

[2342] PG&E Ex-08 at 6-2; PG&E Opening Brief at 766.

2023 expenses and capital expenditure related to PG&E Academy Department is as follows:[2343]

- $38.3 million 2023 expense forecast for department costs ($1.2 million decrease or approximately 3%, as compared to 2020 recorded adjusted costs).
- $1.0 million 2023 capital expenditure forecast (a $43,000 decrease from the 2020 recorded adjusted costs).[2344]

PG&E's capital expenditure forecast is uncontested.[2345]

8.5.1. PG&E

PG&E's 2023 expense forecast for PG&E Academy Department covers expenses for operating and administering the academy at $38.3 million and a capital expenditures forecast.[2346] PG&E notes initial disagreements with the forecast and the planned use of the funds with Engineers and Scientists of California Local 20 and explains that the parties eventually came to an agreement, as set forth in the Memorandum of Understanding filed on September 16, 2022 in this proceeding.[2347] PG&E requests that the Commission adopt the Memorandum of Understanding between PG&E and Engineers and Scientists of California Local 20 resolving all contested issues pertaining to PG&E Academy.[2348] The issues raised by Engineers and Scientists of California Local 20 are described in more detail below.

2343 PG&E Ex-08 at 6-2; PG&E Opening Brief at 767.

2344 PG&E Opening Brief at 767, stating that the PG&E Academy capital expenditure forecast is for the costs of tools, equipment, and maintenance of PG&E's learning facilities.

2345 PG&E Opening Brief at 767; Cal Advocates Opening Brief at 409.

2346 Cal Advocates Opening Brief at 407.

2347 September 16, 2022 Joint Motion of Pacific Gas and Electric Company (U39M) and the Engineers and Scientists of California Local 20 to Admit Late Filed Exhibit into Evidence.

2348 PG&E Opening Brief at 768.

8.5.2. Party Positions

Regarding PG&E's 2023 forecast for PG&E Academy, Cal Advocates and the Engineers and Scientists of California Local 20 present alternative forecasts. Engineering and Scientists of California Local 20 proposes an additional allocation of approximately $3.0 million over the four-year GRC period of 2023-2026, which PG&E states would result in an expense allocation of $725,347 to PG&E Academy for 2023 and the attrition years.[2349] Engineers and Scientists of California Local 20 and PG&E negotiated an Memorandum of Understanding that resolves all issues between the parties with respect to PG&E Academy, which PG&E and Engineers and Scientists of California Local 20 filed in this proceeding on September 16, 2022 by a motion requesting that the Memorandum of Understanding be admitted into the record of the proceeding as PGE Ex-66.[2350] The September 16, 2022 motion also seeks approval of the Memorandum of Understanding by the Commission.

Cal Advocates recommends reducing the expense forecast for PG&E Academy in three areas, (1) A&G Salaries, (2) Gas Training Labor, and (3) Gas Training Non-Labor. Regarding PG&E's 2023 department expense forecast for A&G Salaries of $6.049 million for PG&E Academy, Cal Advocates recommends a lower amount of $5.536 million (a reduction of $513,000) on the basis that variability exists in the more recent historic salary data so a five-year average for PG&E Academy A&G Salaries should be used for the 2023 forecast.[2351] In response, PG&E states that Cal Advocates' recommendation is not reasonable

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[2349] PG&E Opening Brief at 768; ESC Ex-01 at 1 and 2-3 (Table 1).

[2350] PG&E Opening Brief at 770; Joint Motion of Pacific Gas and Electric Company (U39M) and the Engineers and Scientists of California Local 20 to Admit Late Filed Exhibit into Evidence (September 16, 2022).

[2351] CALPA Ex-11 at 51; Cal Advocates Opening Brief at 408; PG&E Ex-21 (Rebuttal) at 6-5.

because Cal Advocates relies on 2021 data, nominal dollars with no labor escalation.[2352]

Regarding PG&E Academy Gas Training, including both labor and non-labor, Cal Advocates recommends a 2023 forecast of $7.572 million, which is a reduction to the PG&E Academy Training 2023 forecast of $29.098 to $26.656 million (a reduction of $2.442 million).[2353] For PG&E Academy Gas Training non-labor, Cal Advocates recommends a 2023 expense forecast of $3.550 million, compared to PG&E's forecast of $4.348 million.[2354] For PG&E Academy Gas Training labor, Cal Advocates recommends a 2023 expense forecast of $4.022 million, compared to PG&E's forecast of $5.666 million.[2355] Cal Advocates recommends the use of a five-year average recorded costs for PG&E Academy Gas Training. Cal Advocates states that PG&E's "aspirational" training targets are inadequately supported.[2356] In response, PG&E states that its 2023 forecast of $5.666 million for labor compared to the 2020 recorded adjusted of $5.16 million is consistent with the forecast driver of standard labor escalation, which Cal Advocates did not include.[2357] Regarding Cal Advocates' use of a five-year average in nominal dollars, PG&E states that a base year dollar is the appropriate value and this value must be escalated to 2023.[2358] PG&E states that its non-labor 2023 expense forecast of $4.34 million compared to 2020 recorded

[2352] PG&E Ex-21 (Rebuttal) at 6-6.

[2353] Cal Advocates Opening Brief at 409.

[2354] Cal Advocates Opening Brief at 409.

[2355] Cal Advocates Opening Brief at 409.

[2356] Cal Advocates Opening Brief at 409.

[2357] PG&E Ex-21 (Rebuttal) at 6-6 and 6-7.

[2358] PG&E Opening Brief at 768.

adjusted of $5.33 million is a $983,000 decrease over the rate case period (2023-2026) and that Cal Advocates' recommendation does not account for increased needs in 2023.[2359]

8.5.3. Discussion

No party contested the September 16, 2022 Memorandum of Understanding between Engineers and Scientists of California Local 20 and PG&E. The Commission grants the request of Engineers and Scientists of California Local 20 and PG&E to enter PG&E Ex-66 into the record of this proceeding. In addition, the Commission finds reasonable the September 16, 2022 Memorandum of Understanding between Engineers and Scientists of California Local 20 and PG&E. Article 4 of the Memorandum of Understanding states the agreement is only enforceable if adopted by the Commission. As a result, the Commission also adopts the Memorandum of Understanding between Engineers and Scientists of California Local 20 and PG&E.

Regarding Cal Advocates recommendation to reduce PG&E's proposal for the 2023 expense forecast for labor and non-labor in PG&E Academy Gas Training, the Commission finds reasonable the use of labor escalation and a 2023 expense forecast that reflects additional needs, as included in PG&E's 2023 expense forecast of $5.666 million for labor and $4.348 million for non-labor for PG&E Academy. Accordingly, the Commission adopts PG&E's 2023 expense forecast of $5.666 million for labor and $4.348 million for non-labor for PG&E Academy Gas Training within PG&E Academy. Regarding PG&E's 2023 department expense forecast for PG&E Academy A&G Salaries of $6.049 million, the Commission finds reasonable PG&E's 2023 expense forecast that relies on

[2359] PG&E Ex-21 at 6-7.

labor escalation, which Cal Advocates does not include. Accordingly, the Commission adopts PG&E's 2023 expense forecast of $6.049 million for A&G Salaries within PG&E Academy.

8.6. Total Compensation Study

Regarding PG&E's Total Compensation Study, PG&E states that employee cash compensation includes a mix of base pay and incentive compensation, with the proportion of incentive compensation increasing as an employee's level in the organization increases.[2360] PG&E prepares the Total Compensation Report in response to the Commission's directive in D.95-12-005.

8.6.1. PG&E

PG&E suggests that its policy of increasing the proportion of employee cash compensation tied to incentives at higher levels in the organization "helps align the leaders' and their team's priorities with those of the broader organization."[2361] PG&E states that over 60% of its employees are represented by one of three labor unions and, as a result, much of PG&E's employee compensation is also dependent on reaching agreements with those unions that can be ratified by their members.[2362] PG&E states that, in accordance with a Commission directive approximately 28 years ago in D.95-12-005, PG&E hired an independent consulting firm—Willis Towers Watson—to perform the Total Compensation Study (also referred to as TCS) for this proceeding.[2363] The Total Compensation Study provides, according to PG&E, an independent analysis of the competitiveness of PG&E's total compensation (cash compensation and

[2360] PG&E Opening Brief at 771.

[2361] PG&E Opening Brief at 771.

[2362] PG&E Opening Brief at 771.

[2363] PG&E Opening Brief at 771.

benefits) compared to the relevant market.[2364] In its Total Compensation Study, Willis Towers Watson found PG&E's 2020 target total compensation was competitive, at 8.9% higher than the median of the market.

8.6.2. Party Position

Cal Advocates states that the Total Compensation Study excluded long-term incentive values and compensation related to long-term incentives.[2365] Cal Advocates disagrees with PG&E's conclusion, which is based on the Total Compensation Report, that PG&E executive compensation falls within the range of competitiveness since it is with a range of +/- 10% points of the market average.[2366] Cal Advocates states that the range proposed in the Total Compensation Study, and also relied upon by PG&E, of +/- 10% points of the market average, is not consistent with the Commission's long-standing standard of 5% as the acceptable market range variance.[2367] Cal Advocates suggests based on its recommended range, PG&E's market comparison for its executive compensation would fall above this variance.[2368] In other areas of this proceeding, where the Commission addresses compensation, Cal Advocates proposes adjustments to PG&E executive compensation on the basis that the Commission should bring PG&E's overall total authorized compensation closer to within 5% of market.[2369] PG&E disagrees with Cal Advocates' characterization

[2364] PG&E Opening Brief at 771; PG&E's Total Compensation Study at PG&E Ex-08 at Ch. 7.

[2365] CALPA Ex-11 at 65; Cal Advocates Opening Brief at 416, *citing to* PG&E Ex-08 at 7-3.

[2366] Cal Advocates Opening Brief at 416.

[2367] CALPA Ex-11 at 65; Cal Advocates Opening Brief at 416.

[2368] CALPA Ex-11 at 65; Cal Advocates Opening Brief at 416.

[2369] CALPA Ex-11 at 65; Cal Advocates Opening Brief at 416. PG&E Reply Brief at 592-593, *citing to* D.95-12-055 at 34, as follows: "[t]otal compensation that is, on average, 105 percent of market levels is likely to be well within the range of compensation in relevant markets."

of the Total Compensation Study stating that the conclusion of the Total Compensation Study was supportive of PG&E's forecast, finding that PG&E's total compensation is competitive with the relevant market.[2370] PG&E concludes that no reductions to PG&E's forecast are warranted based on the TCS.[2371]

8.6.3. Discussion

The Total Compensation Study Report, a report required by the Commission in D.95-12-005, provides an analysis of PG&E's compensation structure.[2372] After review of the party comments on the Study Report, the Commission finds that a more holistic report would provide a more informative picture of compensation within PG&E. The Commission finds that, due to the passage of time since the Commission adopted the directive to prepare such reports in 1995, it is reasonable to adopt refinements to the substance of these report to promote more effective evaluation of PG&E's compensation. Accordingly, the Commission directs PG&E to include in all future total compensation reports provided pursuant to D.95-12-005 additional compensation components, including the long-term incentive values and compensation related to long-term incentives.

8.7. Uncontested Forecasts

Regarding the uncontested 2023 expense forecasts and the uncontested 2021, 2022, and 2023 requests for capital expenditures for Human Resources, as set forth in PG&E Ex-08, the Commission find those amounts reasonable.[2373]

[2370] PG&E Reply Brief at 588-589.

[2371] PG&E Reply Brief at 588-589.

[2372] The Commission addresses a number of other specific compensation forecasts presented by PG&E in separate Sections, herein.

[2373] The uncontested expense and capital expenditure forecasts are set forth at Appendix A of PG&E's Opening Brief at A-17 and A-25.

9. Administrative and General Costs

PG&E's Administrative and General (A&G) costs support all of PG&E's lines of business. The Commission has described A&G costs as follows:

> A&G expenses are of a general nature and are not directly chargeable to any specific utility function. They include general office labor and supply expenses and items such as insurance, casualty payments, consultant fees, employee benefits, regulatory expenses, association dues, and stock and bond expenses.[2374]

PG&E presents its expense and capital expenditure forecasts in PG&E Ex-09 and related documents. PG&E's proposal for costs is set forth below:

- Expense forecast for 2023 of $1,110.9 million (decrease of $12.2 million compared to 2020 recorded adjusted amount of $1,123.2 million).
- Capital expenditure forecast is $0.1 million in 2021, $3.0 million in 2022, and $2.5 million in 2023, $2.5 million in 2024, $2.5 million in 2025, and $2.5 million in 2026.

In this proceeding, PG&E's above-noted capital expenditure forecast for A&G is uncontested.[2375]

Cal Advocates and TURN contest PG&E's A&G expense proposals. Cal Advocates and TURN developed their respective litigation positions through opening testimony, discovery, rebuttal testimony, and hearings. Based on their analyses and expert opinions, neither Cal Advocates nor TURN oppose the majority of PG&E's forecasts for 2023 A&G expenses.

The parties resolved all the disputed areas of PG&E's A&G expense forecasts on November 1, 2022 by a stipulation, with the exception of the wildfire

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[2374] D.00-02-046, *Opinion in PG&E GRC TY 1999* (February 17, 2000) at 243-244.

[2375] PG&E Opening Brief at 775.

liability insurance issues.[2376] This stipulation is referred to herein as "A&G Stipulation" and is included at Appendix G to PG&E's Opening Brief. The dispute regarding wildfire liability insurance was settled by TURN, Cal Advocates, and PG&E on October 7, 2022.[2377] On January 12, 2023 in D.23-01-005, the Commission adopted the settlement submitted by parties resolving the wildfire liability insurance-related dispute.[2378] This previously approved settlement is briefly addressed below, as part of PG&E's total A&G forecast.

The Commission sets forth PG&E's expense forecasts and the stipulated amounts below. The Commission also examines below each of the stipulated results in the A&G Stipulation.

[2376] PG&E Ex-09 at 3-39. Wildfire liability insurance is included in the line item for general liability insurance. (*See* PG&E Ex-09 at 3-15, Table 3-1, line 6.)

[2377] A.21-06-021, PG&E, Cal Advocates, and TURN Motion for Expedited Approval and Adoption of the Attached Settlement on Insurance-Related Issues (October 7, 2022).

[2378] D.23-01-005, Decision Approving Settlement Regarding Wildfire Liability Insurance Coverage (January 12, 2023).

Table 9-A:
Summary of PG&E A&G Expense Forecasts and Stipulations ($000s)[2379]

		PG&E Forecast	Stipulation	Difference
Department Expense	Finance	$54,441	$54,441	$0
	Risk, Audit, and Insurance	$13,220	$13,060	$159
	Compliance and Ethics	$8,298	$8,298	$0
	Regulatory Affairs	$17,323	$17,323	$0
	Law Organization	$46,666	$46,666	$0
	PG&E Corporation, PG&E Executive Offices, Corporate Secretary, Executive Offices, Corporate Secretary	$5,054	$5,054	$0
	Corporate Affairs	$8,890	$8,890	$0
	IT Expense (All Departments)	$1,540	$1,540	$0
Companywide Expense	Bank/Trustee Fees	$9,249	$8,124	$1,500
	Non-Wildfire Insurance	$199,577	$199,577	$0
	Wildfire Liability Insurance	$707,499	$400,000	$307,499
	Settlements, Judgments, and Claims	$36,376	$33,900	$2,476
	Director Fees	$2,440	$1,830	$610
Total Expense		**$1,110,948**	**$798,704**	**$312,244**

The stipulating parties, TURN, Cal Advocates, and PG&E, request the Commission to find the stipulation reasonable in light of the testimony submitted, consistent with law, and in the public interest. As explained below, the Commission finds that the stipulation meets these standards.

9.1. Stipulation of TURN, Cal Advocates and PG&E on Administrative & General Costs

9.1.1. Finance: Bank Fees (Letter of Credit)

PG&E's utility bank fees are fees charged for depository, disbursement, custody, and trustee-related services, as well as fees associated with PG&E's

[2379] The information in the column "PG&E Forecast" is found at: PG&E-22 at 1-6, Table 1-4, line-8 (Department Expenses: $153.892 M) at 1-7, Table 1-5, line 10 (Companywide Expense: $955.516 million (M)) at 1-8, Table 1-6, line 8 (IT Expenses: $1.540M) = $1,110.948M.

working capital facilities. PG&E's forecast of the 2023 bank fees includes $1.75 million in Letter of Credit fees. TURN recommended a reduction of $1.5 million for fees associated with the sale of PG&E's General Office complex. TURN contended the $1.5 million is a non-recurring cost that should be removed from TY 2023 rates. The parties agree upon a TY 2023 expense forecast for this item of $0.25 million (a reduction of $1.5 million from PG&E's request).

9.1.2. Risk, Audit, and Insurance Department Costs: Program Manager and Privileged Internal Audits

PG&E's Risk, Audit, and Insurance Department is responsible for overseeing functions that help the company manage its key risks. These include PG&E's Market and Credit Risk Management, Internal Audit, Insurance and Loss Control, Sarbanes-Oxley compliance, and Third-Party Risk Management. PG&E forecasts $13.22 million for 2023 department expense. Cal Advocates recommends two adjustments. First, Cal Advocates recommends a $0.159 million reduction to remove the cost of filling one of the vacancies for Project Manager, Principal. Second, Cal Advocates recommends a $0.136 million reduction based on its assertion that PG&E incorrectly included amounts in the underlying data from which the 2023 forecast was derived. In particular, Cal Advocates proposes adjustments with respect to the underlying data from 2018 and 2020 for preparation of various internal audit reports that were subject to attorney-client privilege. Cal Advocates states it does not challenge PG&E's assertion of legal privilege but Cal Advocates asserts it cannot determine whether the costs to perform these internal audits are justifiably assigned to ratepayers without access to the requested audit reports.

In the A&G Stipulation, the parties agree to a 2023 expense forecast of $13.06 million (a reduction of $0.159 million from PG&E's forecast).

9.1.3. Risk, Audit, and Insurance: Insurance (Except Wildfire Liability Insurance)

PG&E's insurance costs include forecasts for different types of insurance, (1) property (nuclear, non-nuclear, other), and (2) liability (general, wildfire, Directors and Officers, PG&E Corporate allocation). PG&E's 2023 total insurance expense forecast is $907.1 million, with $707.5 million of this forecast for wildfire liability insurance costs which the Commission resolved in D.23-01-005 (and summarizes below).[2380] The remaining forecast amount is $199.575 million. Cal Advocates and TURN do not oppose PG&E's insurance expense forecast for 2023 of $199.575 million.

9.1.4. Risk, Audit, and Insurance: Risk Transfer Balancing Account for Non-Wildfire Liability

A disputed issue arose regarding the ratemaking treatment of a portion of the above referenced $199.575 million. Regarding this $199.575 million, Cal Advocates and TURN contest PG&E's request that $156 million of the $199.575 million be recorded to an existing balancing account, the Risk Transfer Balancing Account or RTBA.[2381] TURN opposes PG&E's proposal and instead recommends a substantially restructured RTBA such that all costs tracked in that balancing account are subject to reasonableness review by the Commission in a future application proceeding. Cal Advocates suggests that the RTBA no longer be used for PG&E's wildfire liability insurance program.[2382]

[2380] D.23-01-005, Decision Approving Settlement Regarding Wildfire Liability Insurance Coverage (January 12, 2023).

[2381] TURN Ex-17 at 9; CALPA Ex-13 at 14.

[2382] CALPA Ex-13 at 14.

The Commission authorized the RTBA in 2020 as a two-way balancing account to manage the uncertain costs associated with general liability insurance that were not easily forecast.[2383] In doing so, the Commission stated as follows:

> Regarding the establishment of the RTBA, we agree that insurance costs for General Liability coverage has been difficult to predict in recent times because of market conditions and the recent wildfires in California. A two-way balancing account will also allow PG&E to address uncertainty in a timely manner and at the same time ensure that there is adequate insurance coverage.[2384] … Undercollections should be filed as a Tier 2 advice letter to provide flexibility but allow review of costs in excess of the authorized amount.[2385]

PG&E describes the current RTBA terms based on a 2019 Settlement Agreement as:

> PG&E shall establish a two-way RTBA to recover the costs of PG&E's excess liability insurance coverage exceeding its adopted forecast for coverage up to $1.4 billion. PG&E may file a Tier 2 advice letter for coverage beyond $1.4 billion…[2386]

In the A&G Stipulation the parties resolve their dispute as follows: PG&E will use the RTBA to track the costs incurred to procure insurance coverage up to a target of $700 million. If annual incurred non-wildfire liability insurance costs are less than PG&E's forecast of $156 million, PG&E will return to ratepayers in the next annual RTBA true-up the difference between the amount collected and

[2383] PG&E Opening Brief at 794.

[2384] D.20-12-005 at 254.

[2385] PG&E Opening Brief at 794, citing to D.12-12-005 at 403.

[2386] PG&E Opening Brief at 794.

the amount incurred. If annual incurred costs are above the forecast amount of $156 million, PG&E may seek recovery of those costs by application.[2387]

9.1.5. Law: Settlements, Judgments, and Claims

PG&E's 2023 expense forecast is $36.376 million for Settlements, Judgments, and Claims. Cal Advocates recommends a reduction of $3.2 million for 2023 forecast of $33.177 million.

PG&E records the costs of Settlements, Judgments, and Claims in two categories: (1) Settlements and Judgments Costs as part of its litigation function; and (2) Claims payments to third-parties that did not proceed to litigation, alleging personal injury, property damage, and economic loss as a result of PG&E's operations.[2388] PG&E states that it based its 2023 forecasts on the average of the recorded adjusted payments for three-years, 2017, 2018, and 2020. PG&E states it excluded 2019 from the average because most litigation against the company was stayed in that year due to the bankruptcy proceeding.[2389]

Cal Advocates accepts PG&E's forecast for third-party Claims but recommends a reduction in the estimate for Settlements and Judgments. Cal Advocates bases its recommendation on the following: (1) a reduction in PG&E's 2020 recorded costs for Settlements and Judgments, and (2) use of a four-year average (2017-2020) rather than PG&E's average of three-years (2017, 2018, and 2020).[2390] In the A&G Stipulation, PG&E and Cal Advocates agree to a

[2387] PG&E Opening Brief at 795-796.

[2388] PG&E Opening Brief at 801.

[2389] PG&E Opening Brief at 802.

[2390] CALPA Ex-13 at 16.

total forecast of $33.9 million (which the parties describe as the midpoint of parties' litigation positions).[2391]

9.1.6. PG&E Corporation, Executive Offices, Corporate Secretary: Board of Directors Fees

PG&E presents a 2023 expense forecast of $2.44 million for the PG&E and the PG&E Corporation Director Fees and Expenses, including retainer fees paid to directors and other reimbursable expenses related to attendance at, or participation in, board, board committee, or shareholder meetings.[2392] This expense forecast also includes other PG&E and PG&E Corporation activities, such as director transportation (air and ground), lodging, director education, and one PG&E facility tour per year.[2393] The parties differ on the 2023 forecast for Director Fees and Expenses. TURN recommends a 2023 expense forecast of $1.22 million.[2394] TURN and PG&E stipulate to a 2023 expense forecast of $1.83 million (the midpoint of parties' positions) for Director Fees and Expenses.[2395]

9.1.7. Final Values

In the A&G Stipulation, the parties also agree that the final escalation amounts adopted in this decision should apply to any identified values in the stipulation. The Commission finds reasonable this agreement to adjust adopted values in the A&G Stipulation by any final escalation amounts adopted by the Commission in this proceeding.

[2391] PG&E Opening Brief at 803.

[2392] PG&E Opening Brief at 805.

[2393] PG&E Opening Brief at 805.

[2394] TURN Ex-05 at 16.

[2395] PG&E Opening Brief at 805.

9.2. Wildfire Liability Insurance Coverage Settlement

As mentioned above, PG&E presented its forecast for wildfire liability insurance in PG&E Ex-09 and related documents, as part of its A&G forecast. The Commission resolved the dispute regarding PG&E's expense forecast for wildfire liability insurance in D.23-01-005. In this decision, the Commission adopted an unopposed settlement by PG&E, Cal Advocates, and TURN to resolve the structure and funding of PG&E's wildfire liability insurance coverage for the 2023-2026 GRC period. The adopted settlement approves revenue of $400 million (a reduction of $307.499 million) for 2023 for wildfire liability insurance coverage and approves coverage which consists entirely of self-insurance for third-party wildfire claims of less than $1 billion per year. PG&E implemented the $400 million cost approved in D.23-01-005 in Advice Letter 6863-E-A which was approved by the Commission's Energy Division with an effective date of March 1, 2023. Additionally, the adopted settlement approved self-insurance of $400 million for 2024, $200 million for 2025 and $0 for 2026.[2396] The intent of the settlement is to get the Wildfire Self-Insurance Fund to a balance of $1 billion and these approved amounts support that goal.

OP 2.a of D.23-01-005 requires PG&E to file a Tier 2 Advice Letter "providing its best estimate of self-insurance costs for the year such that any adjustments to the revenue requirement may be implemented on January 1st of the following year or as soon as practicable thereafter."[2397] Additionally, PG&E may file up to two advice letters updating its claims costs throughout the year. Since PG&E has already implemented the $400 million cost for self-insurance for

[2396] D.23-01-005 at 20.

[2397] D.23-01-005 at 24.

third party wildfire claims via Advice Letter 6863-E-A, wildfire liability insurance claim costs are variable, and there is a $1 billion target for the fund, wildfire liability self-insurance costs are removed from the Results of Operations Model for this GRC.

9.3. Discussion

The Commission agrees with stipulating parties that the A&G Stipulation, without modification, is reasonable in light of the testimony submitted, consistent with law, and in the public interest.

To approve a stipulation, the Commission must be convinced that the parties had a sound and thorough understanding of the application, issues, underlying assumptions, and record data. Cal Advocates is statutorily charged with representing a broad range of ratepayer interests and has expertly done so over many years. TURN is a long-established organization representing the interests of residential and small business ratepayers. It has participated in many proceedings over decades and received intervenor compensation for its substantial contributions to Commission decisions.

The Commission is convinced that in this proceeding Cal Advocates and TURN each had a sound and thorough understanding of the application, issues, underlying assumptions, and record data, as expressed through their opening testimonies, discovery, rebuttal testimonies, and cross-examination at hearings, plus opening and reply briefs. Accordingly, the Commission finds the A&G Stipulation is reasonable in light of the testimony submitted. This testimony, along with the A&G Stipulation and briefs, is the applicable part of the entire record. Thus, the Commission concludes the A&G Stipulation is reasonable in light of the whole record.

The law requires that adopted test-year results be just and reasonable. All stipulated dollar amounts meet this test. Moreover, the stipulated use of the RTBA reasonably parallels our existing use of the RTBA and does not violate any law. Thus, the A&G Stipulation is consistent with law.

The A&G Stipulation completely and reasonably resolves disputed issues (except wildfire liability insurance which is resolved in D.23-01-005), reflecting a compromise of often strongly held litigation positions. The parties assert that as a compromise of disputed positions on a range of A&G issues, the A&G Stipulation constitutes an integrated agreement that should be approved in its entirety. The Commission understands compromise can be necessary to resolve issues and reach an agreement. The Commission finds the A&G Stipulation reasonable as an integrated agreement. Moreover, stipulations can save the time and limited resources of the parties and the Commission in reaching reasonable results. The A&G Stipulation does provide this benefit and is in the public interest. In addition, the Commission finds the PG&E's uncontested 2023 expense and capital expenditure forecasts in PG&E Ex-09, and related documents, reasonable.[2398]

9.4. Uncontested Forecasts

In addition, as set forth above, PG&E's capital expenditure forecast was not contested in this proceeding. PG&E requested a 2023 expense forecast of $1,110.948 million. The parties stipulated to a reduction of $312.244 million (approximately 28%) for a 2023 expense forecast of $798.704 million.[2399]

[2398] PG&E's Opening Brief, Appendix A at A-25 and A-29 (PG&E's uncontested expense and capital forecasts).

[2399] PG&E Opening Brief at 778.

Regarding the remaining uncontested expense forecasts by PG&E for A&G costs, PG&E Ex-09, the Commission finds those amounts reasonable.[2400]

10. Results of Operations

This section addresses depreciation, taxes, and working cash, which are components of PG&E's revenue requirement presented in PG&E Ex-10. This section also addresses rate base. Regarding the uncontested forecasts for expense and capital expenditures for Result of Operation PG&E Ex-10, the Commission finds those amounts to be reasonable. The uncontested expense and capital expenditure forecasts are set forth at Appendix A of PG&E's Opening Brief at A-17 and A-25. The Commission addresses the contested areas of PG&E's forecast below.

10.1. Depreciation

Depreciation is an accounting tool used to convert capital investments into annual expenses, referred to as depreciation expense. Within the context of ratemaking, depreciation allows utilities to recover the original cost of fixed capital assets less the estimated net salvage over the useful life of the property by means of proportional charges to the utility's annual operating expenses. The utility recovers its costs to buy, install, decommission, and remove assets over the useful life of the assets. Depreciation is a mechanism for customers to pay through rates the portion of the assets' cost from which they receive benefit. This systematic recovery of asset costs over the useful life furthers the concept of intergenerational equity since an asset's life may span several generations of ratepayers who benefit.

[2400] The uncontested expense and capital expenditure forecasts are set forth at Appendix A of PG&E's Opening Brief at A-17 to A-18, A-25 to A-26, and A-29.

The utility's depreciation expense is one of the primary means through which forecast increases in capital investments increase annual revenue requirements (RRQ), which was described as a formula in Section 1.4.3 above. Depreciation expense has traditionally been calculated for ratemaking purposes using the "straight-line" depreciation method in Commission Standard Practice U-4-W, which is defined by the following equation:

$$d = (1 - c)/L$$

where:

d = total life straight-line depreciation rate,

c = average net salvage ratio (gross salvage less cost of removal) during total service life, and

L = total service life of unit or average service life of group of units.

PG&E requests that the Commission approve: (1) a phased-in use of the Units of Production (UoP) method of depreciation to replace the straight-line method; (2) the requested forecasts for depreciation reserve and expense, including PG&E's proposed average service lives estimates, survivor curves and weighted-average depreciation reserve; (3) the requested Depreciation Rates; and (4) its forecast of Decommissioning Expense.

Table 10-A below summarizes PG&E's forecasted depreciation expense for 2023. PG&E requests that the Commission adopt its 2023 forecast of depreciation and decommissioning expense and Weighted Average (WAVG) depreciation reserve, also provided in Table 10-A below, for Electric Distribution (ED), Gas Distribution (GD), Electric Generation (EG), and Gas Transmission and Storage (GT&S).

Table 10-A:[2401]
Summary Of PG&E Request
(Thousands Of Nominal Dollars)

		2023 Depreciation Expense	2023 Decommissioning Expense	2023 WAVG Reserve
1	ED	2,089,409	-	19,273,460
2	GD	741,116	-	7,427,727
3	EG	690,913	77,195	12,557,465
	GT&S	287,553	(48,871)	3,053,241

In support of its request, PG&E states that its depreciation expense has increased since its 2020 GRC due to both growth of plant in service and changes in depreciation rates. PG&E summarizes the changes in depreciation and decommissioning expense from 2020 to 2023, as set forth in the table below:

Table 10-B:[2402]
Depreciation and Decommissioning Expense
Changes 2020 to 2023
(Thousands of Dollar)

Line of Business	2020 Recorded Depreciation & Decommissioning	2023 Proposed Depreciation & Decommissioning	Change Due to Plant Growth	Change Due to Accrual Rates	Change Due to Decommissioning	2020 to 2023 Change
ED	$1,507,452	$2,089,409	$419,328	$162,629	----------	$581,957
GD	482,350	741,116	128,841	129,925	----------	258,766
EG	673,449	768,108	72,173	(34,230)	56,176	94,659
GT&S	261,166	342,556	52,025	44,087	(14,722)	81,390
GRC Before	$2,924,418	$3,941,190	$672,366	$302,411	$41,994	$1,016,772
LM Refund	----------	(103,874)	----------	(51,962)	(51,912)	(103,874)
Total GRC	**$2,924,418**	**$3,837,316**	**$672,366**	**$250,449**	**($9,917)**	**$912,898**

In the following sections, the Commission discusses the UoP and straight-line methods of deprecation, and adopts the straight-line method. That

2401 PG&E Depreciation Opening Brief at 2.

2402 PG&E Depreciation Opening Brief at 3.

discussion is followed by an assessment of service lives (including relevant survivor curves), net salvage (with adoption of TURN's proposed net salvage values for disputed accounts), depreciation rates and expenses. The discussion concludes with decommissioning costs, which are the future cost of removing assets currently providing service.

10.1.1. Units of Production Method to Allocate Gas Distribution Asset Costs

PG&E presents a depreciation proposal for accelerating the utility's recovery of its investment in gas distribution assets referred to as the Units of Production, or UoP, method. PG&E explains that to estimate depreciation expense for most classes of assets, it relied upon the same straight-line methods and procedures used in previous depreciation studies. PG&E also states that the methods of analysis used to estimate average service lives, survivor curves and net salvage for straight-line depreciation are the same as the methods PG&E has used in previous depreciation studies. PG&E states it is now proposing a different depreciation methodology for gas distribution assets. PG&E explains that it makes this proposal due to forecasted declining gas demand triggered by California's Net Zero by 2045 goals which prevent a "business as usual" approach.

PG&E states that its electric and gas distribution assets have historically been depreciated using the straight-line method, in which equal amounts of depreciation are allocated to each year of service. PG&E explains that, under normal operating conditions, most of these types of assets provide relatively equal amounts of service in each year over the life of the assets. According to PG&E, the straight-line method is equitable to different generations of customers because the allocation of equal amounts of costs to each year of service is relatively aligned with the actual service provided by the asset in each year. PG&E argues that should gas demand materially decline, however, the straight-line depreciation does not match the depreciation expense with the level of service provided each year to customers. PG&E reasons that, on a per unit basis, customers in later years receive less service but pay the same amount of depreciation expense as those customers in earlier years. To compensate for what PG&E describes as a "mismatch" between the annual allocated cost of an asset through depreciation expense and the projected decline in customers paying for that asset, PG&E proposes to use the UoP method.

PG&E states that the UoP depreciation methodology allocates costs in proportion to the utilization (expressed as either units of production or units of consumption). By allocating costs over the service lives of its assets in proportion to the expected decline in gas demand, PG&E asserts that the UoP method allows for a more equitable recovery of costs and, as a result, mitigates against the potential for stranded costs that could require future, captive, and potentially low income, customers to pay a disproportionate share of the costs of PG&E's gas assets. PG&E contends the UoP method provides a solution to the concern that low-income and disadvantaged customers could be left with a disproportionate share of costs. PG&E explains that its accelerated UoP depreciation method would decrease future depreciation expense; however, it would increase current depreciation expense.

PG&E further explains that "[t]he UoP method requires a forecast of future production or consumption." PG&E states that it considered two different data sources for its gas demand forecasts: (1) the 2020 California Gas Report, and (2) gas throughput scenarios developed by Energy and Environmental Economics, Inc. (E3) based on a range of assumptions about future electrification.

The "E3 throughput scenarios" provide data forecasts related to gas throughput for a number of electrification scenarios from 2018 to 2050. E3 developed PG&E-specific gas demand scenarios by adapting statewide gas demand scenarios it produced for a previous project which it then scaled to the demand needs of PG&E's service territory. In its UoP calculation, PG&E utilized a forecast based on the E3 Medium Electrification scenario in order to minimize the rate increase associated with its proposal, while noting the Medium-High electrification option was most consistent with PG&E's long-term expectations and closely matched the 2020 California Gas Report fifteen-year forecast of an average gas demand year.

The annual incremental expense of its UoP proposal compared to the straight-line deprecation method is $186.1 million, which PG&E recommends phasing-in over the four years 2023-2026, with approximately $46.7 million additional expense in 2023, $93.4 million in 2024, $139.5 million in 2025, and $186.1 million in 2026. Had PG&E utilized the Medium-High electrification scenario, annual depreciation expense would increase by a further $112.5 million.

TURN, Cal Advocates, and Indicated Shippers (IS) support the Commission's continued use of straight-line depreciation to calculate gas rates. No party supports PG&E's UoP proposal.

According to TURN, the appropriate forum for a review of depreciation methodology for gas assets is the Commission's rulemaking proceeding on gas policy matters, R.20-01-007, and not a single utility's GRC. TURN states that by considering depreciation methodology in an industry-wide rulemaking proceeding, all relevant utilities and stakeholders can participate and, as a result, the Commission will develop an industry-wide approach that balances the risk of recovery of stranded costs between utility customers and shareholders rather than assigning all such costs to customers as the UoP proposal would do. In addition, TURN states that customers are already facing an unprecedented rate increase and, therefore, now is the wrong time to increase depreciation of PG&E's capital assets which will increase near-term customer rates. TURN finally questions reliance on PG&E's forecasts of future gas demand and customers because the forecasts are based on proprietary models and are inadequately explained.

Cal Advocates also supports considering UoP in R.20-01-007 and claims the UoP proposal here is "insufficiently supported, and potentially based on an unreliable forecast." Cal Advocates further notes that PG&E concedes that "the exact timing of these reductions [in gas consumption] have not been definitively established."

Indicated Shippers (IS) argues that PG&E fails to meet its burden of proof to adopt rates determined by UoP because PG&E "has not provided a detailed forecast to represent its own projections." Instead, PG&E relied on E3's 2019 gas demand forecasts, which are based on "…'what if' scenarios… not developed specifically for this GRC ...and not specific to PG&E's service territory." IS also noted that PG&E failed to demonstrate that any other utility has proposed, nor any other jurisdiction adopted, "the use of the UoP Method for depreciating assets exposed to the risk of reduced throughput." Instead, PG&E cited only two cases from several decades ago where UoP depreciation was considered to reflect the risk of depletion of natural resources, i.e., the decline in gas production wells, rather than the risk of declining gas throughput and consumption. IS asserts PG&E departs from common practice and the guidelines in the Commission's Standard Practice (SP) U-4-W.

The Commission recognizes that PG&E's arguments for reducing the risk of stranded costs and high gas rates in future years using the UoP depreciation method may have some merit. Further, the Commission appreciates PG&E's serious attention to the decarbonization goals of the State and the need for changes to "business as usual." However, we not convinced that the UoP approach is a solution ready for adoption in this GRC. As summarized above, the intervening parties have raised numerous questions regarding the UoP depreciation method and how it would be applied to reasonably allocate gas assets through depreciation expense.

In addition, there are other fundamental questions to consider before deciding upon its implementation, such as: (1) whether UoP (or other accelerated depreciation methods) are a more appropriate depreciation methodology than straight-line depreciation for certain gas assets because of forecasted declining gas demand; (2) how alternative depreciation parameters (e.g., salvage values, removal costs, service lives) should account for asset lives differently than the number of years included in standard gas demand forecasts; (3) how accelerated depreciation parameters should be implemented; (4) should regulatory, book, and tax depreciation methods be modified to reflect UoP, if at all; (5) what forecast of utility gas throughput or consumption should be used to calculate rates using the UoP or other alternative depreciation methodology; (6) should accelerated depreciation be used for all gas asset accounts, or just a sub-set of accounts; (7) whether gas demand is the most appropriate proxy for the use of infrastructure whose useful life is declining; (8) how future gas asset GRCs should assess the reasonableness of straight-line depreciation with alternative proposals, such as UoP; and (9) how actual service lives are determined and tracked for all gas and electric infrastructure.

The items above are some examples of the unresolved questions raised in this proceeding pertaining to the use of the UoP method for depreciation of gas assets. Beyond the UoP method, TURN noted numerous other approaches that could achieve the goal of ensuring intergenerational equity and preventing stranded asset costs from falling on a dwindling share of gas ratepayers. We further question whether gas depreciation should be changed without considering accompanying or offsetting changes to electric depreciation, since in general we expect gas use to be declining due to electrification but electricity consumption to increase. This indicates the need to fully consider different approaches before selecting one here. Furthermore, ratepayer affordability considerations and the cost impacts in the current GRC period factor into this decision, and a sufficiently thorough and compelling showing that justifies the immediate implementation of this specific approach has not been made.

Therefore, the Commission finds that the straight-line depreciation method should be adopted for purposes of this GRC, in accordance with Commission SP U-4-W. This is reasonable given the extensive nature of unresolved questions with regard to the UoP alternative. It is also reasonable given the Commission's preference to consider questions regarding gas assets together (including whether to transition to a UoP depreciation method or another method) on an industry-wide basis and not in a single GRC. However, in line with the goals PG&E outlined in proposing the UoP method, we approve a limited change to the service life for some gas services below.

The Commission notes, however, that while it does not adopt PG&E's specific UoP depreciation method proposed here, this does not foreclose PG&E or other utilities or stakeholders from proposing alternative depreciation methods in future GRCs, and any future Commission deliberations in the gas rulemaking. The Commission generally seeks to consider the role accelerated cost recovery may play in protecting a possibly declining number of remaining gas customers from potentially overall higher rates in a coordinated fashion for all similarly situated energy utilities. Thus, a more appropriate forum for the review and consideration of a policy for accelerating the depreciation of gas infrastructure assets through the UoP method is the Commission's ongoing rulemaking proceeding on gas policy matters, R.20-01-007. Parties in R.20-01-007 may address some of the questions raised here, as well as identify and answer other relevant issues.

10.1.2. Straight-Line Depreciation Components

As stated above, the Commission adopts straight-line depreciation for this GRC for all of PG&E's asset classes. Straight-line depreciation is a methodology in which the net capital costs of fixed assets are allocated in equal installments by dividing the net cost by the estimated remaining service life of the assets, which is a linear relationship that is graphed as a straight-line. According to the Commission SP U-4-W, straight-line depreciation expenses are determined annually based on the following formula:[2403]

$$\text{Annual Depreciation Expense} = \frac{\text{(Plant Balance - Net Salvage Value + Removal Costs - Depreciation Reserve)}}{\text{Estimated Remaining Service Life}}$$

Plant balance is equal to the original cost of assets (other than land) used to provide service to customers. Net salvage is generally understood to be the gross salvage realized from resale, re-use or scrap disposal of retired assets less the cost

[2403] Commission Standard Practice U-04-W: Determination of Straight-Line Remaining Life Depreciation Accruals, Revised January 3, 1961, at 11. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M055/K059/55059235.PDF of removal. Removal cost is the estimated future cost to remove existing plant-in-service. Depreciation reserve is the accumulated depreciation expense recorded to date for existing plant-in-service. Remaining Service Life, referred to in PG&E's workpapers as Composite Remaining Life, is the expected average remaining service life of plant-in-service.[2404] Net salvage value, removal costs, and estimated service lives are factors that determine the utility's annual depreciation expenses (per the formula above) and are often referred to as depreciation parameters.

Depreciation Reserve is the total amount of depreciation (in terms of dollars) that has accumulated from the depreciable assets or utility plant. In other words, the Depreciation Reserve is the total amount of annual depreciation expenses that have been charged to ratepayers. After the utility recovers a depreciation expense from ratepayers, the depreciation reserve is credited, or increased, by the amount of the depreciation expense, resulting in an accumulated depreciation reserve balance. The depreciation reserve is treated in the rate base calculation as a reduction to the rate base. As depreciation expenses are recognized, and the depreciation reserve is increased by the amount of depreciation expenses, the utility's rate base is also reduced by the same amount of accumulated depreciation expenses.

The straight-line depreciation method is currently used for all PG&E assets. PG&E's depreciation study provides the input data for each asset class for the following components of depreciation: survivor curve type with Average

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[2404] PG&E Ex-10 WP, Vol. 2 at WP 11-7, Table 11-9, Column H.

Service Life, Composite Remaining Life and Net Salvage Rate.[2405] The disputed inputs are discussed below.

10.1.3. Service Life (Survivor Curves, Average Service Life, and Composite Remaining Life)

Because utility assets generally have service lives that span several generations of ratepayers, a systematic and fair apportionment of the asset costs, through an appropriate amount of depreciation expense every year, is important for maintaining the equity of intergenerational ratepayers. A systematic and fair apportionment of the utility asset costs allows each generation of ratepayers to pay their share of depreciation expenses for the use of the assets, so that one generation of ratepayers does not have to bear substantively more of the asset costs than others. In TURN's analysis, it apportions utility asset costs using a "retirement-rate method" to develop an "observed-life table" showing the percentage of property surviving at each age interval. From the numerous studies of utility properties made by many individuals and organizations under widely varying circumstances, it is known that the useful life of large groups of similar assets generally follow a similar pattern. This pattern is such that the portion of an original group surviving at a time may be statistically predicted as a function of age. A graph or curve illustrating this relationship is known as a survivor curve. These curves are used to derive the estimated or composite remaining service life values which are used to calculate depreciation rates according to the above formula.

PG&E made survivor curve recommendations for nearly 110 depreciation accrual accounts across electric, gas and common plant assets. PG&E's survivor curve recommendations are based on a few broad factors not relied on by TURN

[2405] PG&E Ex-10 at 12-1.

and Cal Advocates. First, PG&E uses data prior to 1999 because PG&E asserts that using a longer period of data to correspond to the expected life cycles of most of PG&E's assets is more reliable. The concern raised by parties about this approach centers around the lack of availability of data. Prior to 1999, some relevant data is not available, including recorded installation years and the recorded age of retirements. Beginning in the 2017 GRC, PG&E began using a different method of analysis that required a longer period of data. Since such data was not available, PG&E used statistical aging or simulations to assign vintage years of installation to retirements in the pre-1999 data.

Second, PG&E emphasizes the need to consider significant changes that are likely to arise in the coming years due to the state's policy of planning to achieve Net Zero greenhouse gas emissions by 2045. Net Zero refers to the plan published by the California Air Resources Board in 2022. This plan lays out a path to achieve targets for carbon neutrality and reduce anthropogenic greenhouse gas (GHG) emissions by 85 percent below 1990 levels no later than 2045, as directed by Assembly Bill 1279.

TURN recommends adjusting PG&E's depreciation rates to reduce PG&E's proposed depreciation accrual by $588 million based on plant balances as of December 31, 2020. TURN's forecast is based on proposed changes to two depreciation parameters: service lives, addressed here, and net salvage values, addressed below. TURN recommends adjustments to service lives for 11 electric accounts, six gas accounts, and one common plant account. TURN supports its recommendation with an approach that relies on objective data recorded by PG&E (rather than simulated data), the employment of mathematical and visual curve fitting, and expert judgment to select reasonable survivor curves for each account in dispute. Like PG&E, TURN used the "retirement rate method" to develop an "observed life table" that shows the percentage of property surviving at each age interval. The resulting patterns reveal survivor curves reflecting the utility's experience of plant retirements within specific accounts.

Cal Advocates proposes an adjustment to PG&E's recommendations for one electric account, Account 364, Poles, Towers and Fixtures, and two gas accounts, Account 376, Mains and Account 380, Services. Cal Advocates recommends different survivor curves for these three accounts because, according to Cal Advocates, its survivor curves provide the best fit to the most relevant historical data.

10.1.3.1. Survivor Curve for Electric Poles, Towers and Fixtures Account 364 (Poles)

For the account including electric poles (Account 364), PG&E proposes retaining its currently authorized survivor curve (44-R2) with a corresponding composite remaining life of 34.91 years.[2406] In contrast, Cal Advocates recommends adopting survivor curve 47-R1.5 with a composite remaining life of 38.47 years given better alignment with recorded data.[2407] TURN recommends a 52-R2 curve with a composite remaining life of 42.68 years.[2408]

PG&E recommended survivor curve 44-R2 by giving more consideration to the overall experience band starting before 1999 than the more recent experience band because it encompassed a longer period of historical data. But Cal Advocates explained that PG&E's proposal to continue the existing survivor curve, 44-R2, aligns more closely only to the first experience band.[2409] PG&E also

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[2406] PG&E Ex-10 WP, Vol. 2 at WP 11-8, Table 11-9, Line 87.

[2407] Cal Advocates Ex-15 WP at 90.

[2408] TURN Ex-18, Attachment 1; PG&E Depreciation Opening Brief at 6-7.

[2409] Cal Advocates Depreciation Opening Brief at 5-8.

selected its recommended survivor curve based on its proposal to underground 10,000 miles of overhead electric lines because, according to PG&E, undergrounding overhead lines will result in an overall shorter service life for those assets currently in service than has been experienced previously. However, the Commission notes that the proposal to underground 10,000 miles for overhead electric lines has not been approved, in its entirety.

The Commission finds Cal Advocates' recommendation to be the most reasonable because it aligns closely with both the first and third curves of recorded retirement data. Neither PG&E nor TURN fully addressed, nor convincingly argued against, Cal Advocates' recommendation to select survivor curve 47-R1.5 for Account 364 (Poles) in briefing.[2410] Accordingly, the Commission adopts survivor curve 47-R1.5 for Electric Poles, Towers and Fixtures Account 364, with a corresponding composite remaining life of 38.47 years.

10.1.3.2. Survivor Curve for Gas Mains Distribution Plant Account 376 (Gas Mains)

For the gas mains (Account 376), PG&E's workpapers provide curves of data using an experience band of: (1) 1909-2020; and (2) 1999-2020.[2411] PG&E proposes retaining the currently authorized survivor curve 57-R3, with a corresponding composite remaining life of 44.37 years, because if any change

[2410] For Electric Poles, Towers and Fixtures Account 364 TURN recommended survivor curve 52-R2. PG&E Depreciation Opening Brief at 7.

[2411] PG&E Ex-10 WP, Vol. 5 at WP 12-1003 to WP 12-1009.

should be made, the Net Zero by 2045 goal could result in shorter service lives than those reflected in historic averages.[2412]

Cal Advocates recommends adopting survivor curve 60-R3 with a longer composite remaining life of 47.8 years because it aligns more closely to the experience data PG&E chose even though Cal Advocates' selected survivor curve has a longer average service life and resulting lower depreciation rate.[2413]

PG&E replies that Cal Advocates' estimated service life is unreasonable given California's decarbonization goals because California's greenhouse gas emissions targets "may result in the retirements of mains." In response, Cal Advocates states that PG&E already retires gas mains "due to replacements resulting from PG&E's asset management programs," not California's greenhouse gas emission targets.

The Commission finds that PG&E's recommendation to retain the current survivor curve for this account does not accurately reflect all factors involved in transitioning away from gas assets to meet California's decarbonization goals. Additionally, it is by no means clear, nor compellingly demonstrated in the record, that the entire gas mains asset class will be retired early at a consistent rate due to our decarbonization goals. For these reasons, the Commission does not adopt PG&E's recommendation. The Commission finds survivor curve 60-R3 to yield a reasonable estimate of the remaining service life of 47.8 years for the Gas Mains Distribution Plant Account 376 because it more closely aligns with historical experience and adopts survivor curve 60-R3 for Account 376.

[2412] PG&E Depreciation Opening Brief at 7; PG&E Ex-23-E at 12-95 to 12-97; PG&E Ex-10 Workpapers, Vol. 2 at WP 11-10, Table 11-9, Line 183.

[2413] Cal Advocates Depreciation Opening Brief at 8-11 and Cal Advocates Ex-15 WP at 90.

10.1.3.3. Survivor Curve for Gas Services Distribution Plant Account 380 (Gas Services)

PG&E proposes lowering the survivor curve from the currently authorized curve of 57-R3 to 55-R3, which would reduce the corresponding remaining life to 41.02 years.[2414] For this account, PG&E asserts that the best statistical fit of the data shows average service life of 60 years or more, but PG&E proposes an average service life of 55 years for services. In support of the lower service life, PG&E states that it is reasonable to expect a shorter service life in the future for this account compared to its historical experience for services to take into consideration California's greenhouse gas emission reduction goals.

Cal Advocates recommends the Commission adopt survivor curve 59-R3 with a corresponding remaining life of 45.08 years. In support, Cal Advocates' states that recommendation is based on the best statistical fit of the data.[2415] Cal Advocates argues that it is improper for PG&E to propose a strategy to address greenhouse gas emission reduction goals here because the Commission currently has an open rulemaking to develop a long-term, industry-wide strategy for gas utilities to respond to state and municipal greenhouse gas emission targets.

The Commission finds that accelerating depreciation for gas service assets in this GRC is consistent with denying the replacement of gas services tracked in MAT 50B that may be repurposed to support electrification, as discussed in Section 3.12 above. In addition, accelerating the depreciation of gas services is a

[2414] PG&E Ex-10 WP, Vol. 2 at WP 11-10, Table 11-9, line 186.

[2415] Cal Advocates Depreciation Opening Brief at 11-13; Cal Advocates Ex-15 WP at 90. For this account, TURN recommends survivor curve 60-R3, with a composite remaining life of 45.93 years. TURN Ex-18, Attachment 1.

potential alternative to the broader UoP approach discussed above. Moreover, the Commission finds that it is neither premature nor speculative to expect some reduced use in gas services distribution plant, and the Commission approves a slight acceleration in depreciation that will match the expected reduced use of this asset.

Accordingly, the Commission finds PG&E's proposed survivor curve 55-R3 to be a reasonable estimate of the remaining service life of 41.02 years for the Gas Services Distribution Plant Account 380 and adopts survivor curve 55-R3 for Account 380.

10.1.3.4. Survivor Curves for the Remaining Disputed Accounts

The parties do not dispute the vast majority of the survivor curve recommendations PG&E made for the remaining 107 depreciation accrual accounts. As discussed above, TURN supports its recommendations for the remaining 10 electric, four gas, and one common plant account partly because PG&E's survivor curve selections are based on pre-1999 simulated data. In response, PG&E contends that shorter depreciation service lives are needed to support greenhouse gas emission reduction goals. Cal Advocates and TURN both assert that PG&E's recommendations to increase depreciation to further greenhouse gas reduction goals to be premature and speculative.

The Commission agrees with Cal Advocates and TURN, with the exception of the acceleration of depreciation by selecting a survivor curve with a shorter service life for gas services distribution plant account 380 above. Further, the Commission finds reasonable the application of the more recent experience bands used by TURN to fit survivor curves for the remaining depreciation accrual accounts in dispute given that the Commission reasonably expects that the future of the electric and gas industries will be different than the past.[2416] In addition, due to continuing uncertainty regarding the future service lives of gas and electric assets, the Commission confirms its interest in maintaining a gradual approach to changes in depreciation,[2417] which must be driven by specific aging analyses.[2418] Accordingly, the Commission adopts the survivor curves recommended by TURN for the remaining depreciation accrual account-curves in dispute, and the remaining service lives as provided in TURN's workpapers,[2419] shown below.

Table 10-C: [2420]
Comparison of PG&E and TURN
Survivor Curves and Service Life Estimates

	Acct No./Description	Current Iowa Curve	PG&E-Proposed Iowa Curve	TURN-Proposed Iowa Curve
ELECTRIC PLANT	353 – ET Station Equipment	R1.5 – 55	R2 – 55	R1.5 – 63
	362 – ED Station Equipment	R1.5 – 46	R1 – 50	R1 – 53
	365 – ED OH Conductors	R2 – 46	R1.5 – 44	R1.5 – 48
	367 – ED UG Conductors	R3 – 50	R3 – 52	R3 – 55
	368.01 – ED OH Line Transformers	R2.5 – 32	R2.5 – 32	R2.5 – 35
	368.02 – ED UG Line Transformers	R2.5 – 33	R2.5 – 34	R2.5 – 37
	369.01 – ED OH Services	R2.5 – 55	R2.5 – 55	R2 – 64
	369.02 – ED UG Services	R4 – 50	R4 – 50	R3 – 58

[2416] TURN Depreciation Opening Brief at 10-11.

[2417] D.14-08-032 at 598-599.

[2418] TURN Depreciation Reply Brief at 5- 6.

[2419] PG&E Depreciation Opening Brief at 3; TURN Ex-18, Attachment 1.

[2420] TURN Depreciation Reply Brief at 3, except rows for accounts 364, 376, and 380 removed since other party proposals are adopted per the previous section above.

	Acct No./Description	Current Iowa Curve	PG&E-Proposed Iowa Curve	TURN-Proposed Iowa Curve
GAS PLANT	367 – GT Mains	R2 – 66	R2 – 65	R2 – 68
	378 – M&R Station Equipment	R2 – 55	R2 – 55	R2 – 59
	381 – Meters	S1 – 28	S1 – 28	S1 – 30
	383 – House Regulators	R2 – 28	R2 – 28	R2 – 32

10.1.4. Net Salvage Estimates

For straight-line depreciation, net salvage is generally understood to be the gross salvage realized from resale, re-use or scrap disposal of retired assets less the cost of removal.[2421] For ratemaking purposes, net salvage is expressed either as a dollar amount or as a percent of the original plant cost (the net salvage rate, or NSR). Salvage and removal costs are typically based on current dollars (when the assets are removed from service), while retirements are based on historical dollars. Often, the net salvage for utility assets is a negative number (or percentage) because the cost of removing the assets from service exceeds any proceeds received from selling the assets. Future net salvage is part of the cost of a capital asset and differs from the original cost of the asset only in that net salvage cost occurs at the end of the asset's life rather than the beginning. The intent of depreciation is to equitably allocate the costs of a utility's assets over their service lives. Doing so results in intergenerational equity as customers pay the cost of assets providing service. Depreciation for net salvage is recorded to the Accumulated Depreciation account and, in turn, is an adjustment to rate base. As a result, when the net salvage is positive, the inclusion of net salvage in

[2421] Commission Standard Practice U-4-W: Determination of Straight-Line Remaining Life Depreciation Accruals, Revised January 3, 1961, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M042/K177/42177433.PDF. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M055/K059/55059235.PDF.

depreciation results in rate base being lower than if net salvage were not included in depreciation.

Based on its depreciation study, PG&E proposes net salvage estimates for approximately 110 accounts across electric, gas, and common plant in the amounts shown below as a percentage of the original plant cost.[2422]

Table 10-D [2423]
PG&E Proposed Net Salvage Estimates

FERC Account	2020 GRC/2019 GT&S PG&E Estimate	Currently Authorized Estimate	PG&E Estimate	Cal Advocates Estimate	TURN Estimate
ELECTRIC PLANT					
362, Station Equipment	(60)	(40)	(60)	(45)	(45)
364, Poles, Towers & Fixtures	(175)	(150)	(175)	(156)	(156)
367, UG Conductors & Devices	(80)	(65)	(80)	(69)	(69)
368.01, Line Transformers – OH	(40)	(30)	(40)	(34)	(34)
368.02, Line Transformers – UG	(25)	(25)	(35)	(35)	(28)
GAS PLANT					
352, Wells	(15)	(15)	(25)	(25)	(18)
353, Lines	(50)	(35)	(50)	(50)	(39)
367, Mains	(70)	(54)	(75)	(59)	(59)
376, Mains	(55)	(55)	(75)	(60)	(60)
378, Measuring & Regulating Sta Equipment	(40)	(40)	(50)	(50)	(43)
380, Services	(100)	(81)	(100)	(86)	(86)

PG&E's request for the annual accrual of net salvage for the largest seven accounts is $900 million, an increase of $100 million over the 2020 request of $800 million.[2424] In support of its proposed increase in net salvage rate estimates,

[2422] PG&E Ex-23-E at 12-106 (Table 12-18).

[2423] PG&E Depreciation Opening Brief at 14 (Table 12-18).

[2424] Cal Advocates Depreciation Opening Brief at 14.

PG&E claims that its estimates are conservative when compared to the historical data and represents gradual change of less than 25 percentage points.[2425]

Cal Advocates disputes PG&E's rates for the accounts provided in the Table above for the following reasons: (1) PG&E's rates are unverified, and (2) PG&E's rates are not consistent with Commission precedent, which only allow gradual increases in net salvage rates.[2426] In support of its first argument, Cal Advocates contends that PG&E has not documented the historical cost of removal that PG&E used to estimate net salvage rates for which it seeks funding.[2427]

In support of its second argument, Cal Advocates recommends changes to PG&E's proposed increases in net salvage percentages for four electric accounts and three gas accounts based on the Commission's policy of gradualism as it has been applied to net salvage rates.[2428] Gradualism is a principle by which:

> …there is a recognized need to revise estimated parameters, but where the change is allowed to occur incrementally over time rather than all at once. Applying gradualism thus limits the approved increase that would otherwise be warranted, all else being equal, and mitigates the short-term impact of large changes in depreciation parameters.[2429]

In other words, "gradualism" limits any change to depreciation parameters to small, gradual modifications, so that significant short-term impacts to depreciation expenses can be avoided.

[2425] PG&E Depreciation Opening Brief at 13-16.

[2426] Cal Advocates Depreciation Opening Brief at 15.

[2427] Cal Advocates Depreciation Opening Brief at 14-17.

[2428] Cal Advocates Depreciation Opening Brief at 15.

[2429] D.20-12-005 at 282, fn. 299, *citing to* D.14-08-032 at 596-602.

Cal Advocates asserts that PG&E's proposal to increase the net salvage percentages by more than 19% (on average) unnecessarily adds to customer rate shock and intensifies rate affordability issues. Instead, Cal Advocates proposes changes in net salvage percentages compared to current percentages in the table above to between four and 14 percent, arguing the 25-percentage point limit applied to net increases is not appropriate in this GRC because PG&E's proposed increase in the 2014 GRC (of approximately $460 million) was small compared to PG&E's large overall rate increase (of approximately $3.13 billion) in this GRC.[2430]

TURN recommends that the Commission adopt its proposed net salvage estimates for five electric accounts and six gas accounts because they are more consistent with the concept of gradualism adopted in PG&E's 2014 GRC in D.14-08-032.[2431]

In response, PG&E argues that the Cal Advocates and TURN proposals are inconsistent with the principle of gradualism for two reasons: (1) the Cal Advocates and TURN proposals provide too little recovery of net salvage costs to be equitable; and (2) if the Commission were to always limit changes in net salvage to 25 percent of an applicant's proposal no matter the proposal itself, then depreciation would never be correct or reasonable.[2432]

The Commission does not adopt PG&E's proposed increases in net salvage values for the following reasons. First, PG&E's proposed net salvage values are inconsistent with principles of gradualism. Commission decisions have limited increases in net salvage rates to 25 percent of current net salvage rate

[2430] Cal Advocates Depreciation Opening Brief at 19.

[2431] TURN Depreciation Opening Brief at 11-14.

[2432] PG&E Depreciation Reply Brief at 21-22.

percentages.[2433] A limit on net increase is different than reducing the proposal by 25 percent.[2434] For example, PG&E's proposed net salvage percentage for station equipment (FERC Account 362.00) of 60 percent is over the current percentage of 40 percent by 50 percent.[2435] The same is true for three other estimates of PG&E's that Cal Advocates disputes.[2436]

Second, although PG&E has improved the explanation of its cost of removal accounting system,[2437] PG&E has not convincingly demonstrated how the estimates of net salvage percentages for the disputed accounts are reasonable compared to historical data.[2438] Stating that its estimates based on its historical data are conservative does not demonstrate how PG&E meets its burden to show that its salvage value estimates are more reasonable than TURN's modest estimates, which are all within 25 percent of current net salvage rates. Accordingly, the Commission adopts TURN's estimates of net salvage percentages for the 13 accounts in dispute set forth in the table above along with PG&E's uncontested net salvage rates.[2439]

10.1.5. Adopted Depreciation Rates and Expenses

Depreciation rates are calculated per the methodology in Commission SP U-4-W using adopted remaining service lives and net salvage rates.[2440] For undisputed accounts, PG&E's workpapers show the derivation of the adopted

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[2433] D.14-08-032 at 602; D.21-08-036 at 511- 512.

[2434] PG&E Depreciation Reply Brief at 20.

[2435] (60-40)/40 x100 = 50%.

[2436] Accounts 368.01 (Line Transformers – Overhead) and 367.00 (Mains) and 376.01 (Mains).

[2437] PG&E Depreciation Reply Brief at 22-29.

[2438] PG&E Ex-10 at 12-68; PG&E Ex-23 at 12-105 to 12-113.

[2439] PG&E Ex-10 WP, Vol. 2 at 11-1 to 11-6, Table 11-8.

[2440] Commission SP U-4-W Section 8 and examples at 90 and 91, Exhibits B-1 and B-2.

depreciation rates consistent with Commission SP U-4-W.[2441] For disputed accounts addressed above, Table 10-E below provides the adopted depreciation parameters and the resulting depreciation rates.

Table 10-E:
Adopted Depreciation Rates for Disputed Accounts

		Adopted Values					
FERC Acct	Description	Net Salvage (%)	Average Service Life (Yrs)	Curve Type	Composite Remaining Life (Yrs)	Annual Accrual Rate (%)	PG&E Proposed SLD Rate (%)
ELECTRIC PLANT							
353.02	Station Equipment - Step Up Trnsfrms	*(5)*	**63**	**R1.5**	**40.62**	0.58%	0.75%
353.03	Station Equipment - Step Up Trnsfrms (Comb. Cycle)	*(5)*	**63**	**R1.5**	**54.62**	1.21%	3.54%
362	Station Equipment	**(43)**	**53**	**R1**	**43.58**	2.61%	3.22%
364	Poles, Tow ers and Fixtures	**(156)**	**47**	**R1.5**	**38.47**	5.57%	6.68%
365	Overhead Conductors and Devices	*(75)*	**48**	**R1.5**	**37.44**	3.30%	3.67%
367	Underground Conductors and Devices	**(69)**	**55**	**R3**	**40.00**	2.87%	3.39%
368.01	Line Transformers - Overhead	**(34)**	**37**	**R2.5**	**25.89**	3.99%	4.96%
368.02	Line Transformers - Underground	**(28)**	**34**	**R2.5**	**28.78**	3.44%	4.09%
369.01	Services - Overhead	*(125)*	**64**	**R2**	**47.86**	3.16%	3.96%
369.02	Services - Underground	*(45)*	**58**	**R3**	**40.20**	2.14%	2.73%
GAS PLANT							
352	Wells	**(18)**	*40*	*R2*	*29.94*	3.07%	3.31%
353	Lines	**(39)**	*50*	*R4*	*35.56*	2.91%	3.22%
367	Mains	**(59)**	**68**	**R2**	**55.43**	2.34%	2.77%
367	Mains-Stanpac	**(59)**	**68**	**R2**	**51.03**	2.61%	3.11%
376	Mains	**(55)**	**60**	**R3**	**47.80**	2.47%	3.12%
378	Measuring and Regulating Station Equip.	**(43)**	**59**	**R2**	**51.49**	2.39%	2.74%
380	Services	**(86)**	**60**	**R3**	**45.93**	2.75%	3.42%
381	Meters	*(50)*	**31**	**S1**	**22.11**	4.99%	5.71%
383	House Regulators	*(15)*	**32**	**R2**	**20.78**	3.25%	3.94%

Bold values are from TURN or Cal Advocates
Italicized values are from PG&E

Applying these depreciation rates in the Results of Operations model reduces PG&E's total 2023 depreciation expense from $3,809 million to $3,366 million.[2442]

[2441] PG&E Ex-10 WP, Vol. 2: Table 11-8 at 11-1 to 11-6 provides depreciation parameters and the resulting accrual or depreciation rates; Table 11-9 at 11-7 to 11-14 provides the derivation of these rates.

[2442] PG&E forecast values from PG&E Ex-64 (JCE) at 2-654 and the adopted value is found at Appendix A, Table 3, Line 27).

10.1.6. Decommissioning Expense

The Commission SP U-4-W specifies that current depreciation rates shall include the future cost of removing assets currently providing service, net of any proceeds from salvage. PG&E states that the decommissioning of PG&E's generating units in a safe, prudent, and environmentally sound manner is a cost of providing service to its customers. PG&E states that its decommissioning cost estimates are updated periodically to reflect changes in regulatory requirements, technology, and general economic conditions, such that the amounts collected for decommissioning would equal the actual costs when expended. The decommissioning accruals will be credited to the decommissioning reserve, reducing rate base (and the associated returns on rate base).[2443]

10.1.6.1. Pleasant Creek Gas Storage Facility

PG&E states that it is attempting to sell the Pleasant Creek natural gas storage facility.[2444] PG&E states that there is currently no signed purchase and sale agreement.[2445] PG&E forecasts $4.338 million in 2023 for depreciation expense and $27.547 million for decommissioning expense for the GRC period.[2446] TURN recommends that the $4.338 million in Pleasant Creek 2023 depreciation expense and $12.2 million of the $27.547 million for decommissioning be subtracted from PG&E's forecast for this rate case period

[2443] PG&E Depreciation Opening Brief at 36.

[2444] PG&E Ex-23 at 11-10.

[2445] PG&E Depreciation Opening Brief at 37-38.

[2446] For depreciation expense, *see* PG&E Ex-10 WP, Vol. 2 at WP 11-383, Table 11-66, sum of depreciation expense values in lines 1-14. For decommissioning expense, *see* PG&E Ex-03 at 7-58, Table 7-18: $13.561 million in 2023; $13.782 million in 2024; $0.204 million in 2025; and zero in 2026.

(2023-2026) and dealt with in a separate application proceeding pursuant to Pub. Util. Code section 851 in the event the gas storage facility is sold.[2447]

The Commission finds that it reasonable to adopt PG&E's proposed depreciation and decommissioning costs since PG&E will continue to maintain the Pleasant Creek gas storage facility until a sale is approved. Therefore, as the Commission noted in the 2020 GRC, "[t]he amount of the decommissioning reserve is based on the assets that PG&E currently has and it is not reasonable to assume that assets will be sold absent more concrete evidence."[2448]

The record of this proceeding does not indicate the PG&E has completed a sale of this facility. If this facility is sold, the Commission will at that time address the calculation of gains or losses, and any refund or collection from customers, including depreciation and decommissioning, in PG&E's application proceeding under Pub. Util. Code section 851. That application proceeding will provide an efficient process for handling potential adjustments and consistent with the Commission's historical practices and direction provided in the 2020 GRC.[2449] Accordingly, the Commission does not adopt TURN's recommendation to subtract PG&E's depreciation and decommissioning expense forecast for the Pleasant Creek storage facility at this time.

10.1.6.2. Los Medanos Gas Storage Facility

If the Los Medanos gas storage facility is retained, PG&E proposes to refund the excess depreciation ($52.0 million) and the accrued decommissioning costs ($51.9 million) over one year, 2023.[2450] The Los Medanos facility is being

[2447] TURN Depreciation Opening on Brief at 28-29.

[2448] D.20-12-005 at 363, FOF 155.

[2449] PG&E Depreciation Reply Brief at 49.

[2450] TURN Depreciation Opening Brief at 29.

retained. Therefore, the Commission finds that PG&E shall refund the excess depreciation ($52.0 million) and the accrued decommissioning costs ($51.912 million) in 2023 for a total of $103.874 million.[2451]

10.2. State and Federal Income Tax

According to PG&E, its tax expense is a calculated amount dependent on: (1) expenditure estimates provided by witnesses in this case; (2) past Commission decisions on how to perform the calculation; and (3) current tax laws.[2452] PG&E claims its forecast for income tax expense is reasonable because it: (1) accurately reflects the tax laws in its calculation of tax expense; (2) uses Commission-mandated accounting and ratemaking methods; and (3) calculates Federal Income Tax (FIT) and California Corporate Franchise Tax (CCFT) taxable income using appropriate deductions and adjustments equivalent to, or forecasted from, amounts filed in its federal and state tax returns and/or financial statements.[2453] PG&E's testimony, as of February 28, 2022, forecasts $15.339 billion for the 2023 revenue requirement, of which state and federal income taxes are $166.106 million and $285.488 million respectively.[2454]

In the Economic Recovery Tax Act of 1981, Congress mandated that utilities subject to cost-of-service regulation should account for the tax benefit of certain expenditures by using a "normalization" method of tax accounting. The Commission issued Order Instituting Investigation 24 (OII 24) to consider tax issues and adopted normalization accounting when it was required for taxpayers to be eligible to claim accelerated depreciation under federal law. Commission

[2451] PG&E Depreciation Reply Brief at 49-50.

[2452] PG&E Ex-10 at 13-1.

[2453] PG&E Ex-10 at 13-2.

[2454] PG&E Ex-10, Appendix A, at A-3, Table A: Table 2, lines 1, 24, and 25.

decisions have ordered "flow-through" tax accounting for other categories of expenditures.[2455]

Commission decisions and IRS rules dictate the use of normalized or flow-through tax accounting for specific tax and book timing differences to determine the amount of tax benefits reflected in the revenue requirement. Ratemaking with flow-through tax accounting uses the amount of the forecasted tax deduction to determine the amount of the tax benefit reflected in the revenue requirement. The tax benefit reflected in the revenue requirement is equal to the forecasted cash savings. In contrast, normalized tax accounting uses the amount of the book expenditure to calculate the TY amount of the tax benefit reflected in the revenue requirement. In this case, the tax benefit forecasted in rates is different from the forecasted cash saved by the utility due to the tax deduction. This adjustment results in deferred taxes. The normalization tax accounting method calls for a rate base adjustment for this difference between the tax benefit in rates and forecasted cash saved. In the discussion of adjustments presented in its testimony, PG&E specifies when it has used flow-through or normalized tax accounting.[2456]

PG&E asserts that it computes CCFT taxable income in accordance with the statutory requirements of the California Revenue and Taxation Code (R&TC). The starting point for the calculation is pre-tax book income. Pre-tax book income is adjusted for the tax computation. Tax adjustments that are common to both FIT and CCFT are combined with tax adjustments that are unique to CCFT to compute CCFT taxable income from pre-tax book income.[2457]

[2455] PG&E Ex-10 at 13-7.

[2456] PG&E Ex-10 at 13-8.

[2457] PG&E Ex-10 at 13-11.

Similarly, PG&E asserts that it computes federal taxable income in accordance with the statutory requirements of the Internal Revenue Code (IRC). The starting point for the calculation is pre-tax book income. Tax adjustments that are common to both FIT and CCFT are combined with tax adjustments that are unique to FIT to compute FIT taxable income from pre-tax book income.

10.2.1. Deduction of CCFT State Income Tax from Federal Income Tax

For FIT return filing purposes, section 801 of TRA 86 requires taxpayers such as PG&E to deduct CCFT on a privilege year basis—i.e., the prior year CCFT becomes deductible on the first day of each new year, when PG&E exercises its franchise privilege to do business in California. Thus, CCFT for 2022 (income year) would be deductible for FIT purposes in 2023 (privilege year).

In D.89-11-058, the Commission concluded that CCFT is deductible for FIT purposes on a privilege year basis and adopted the "flow-through" method for all utilities where the prior year's CCFT adopted ratemaking amount would be used for the CCFT deduction when setting rates. For 2023, PG&E's testimony shows an estimated prior year CCFT deduction amount for 2022 of negative $51.45 million[2458] and proposes that it be deductible for FIT purposes in 2023 based on its contention that the flow-through tax accounting used for this adjustment agrees with the accounting used for this item in this proceeding and in previous rate cases.[2459] In D.89-11-058, the Commission also stated that "the utilities may restate their adopted test year and attrition year summaries of earnings for 1987 onwards in all cases where the Commission has adopted the

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[2458] PG&E Ex-10 (Table 13-2) (column E, line 32).

[2459] PG&E Ex-10 at 13-14.

prior year's CCFT amount in a Commission decision."[2460] In addition, "all results of operations for all utilities shall reflect the flow-through treatment for the CCFT deduction in computing federal income tax expense."[2461] This method is based on passing on the actual adopted prior-year CCFT as the deduction rather than an estimated CCFT to ratepayers.

The Commission determines here, however, that PG&E's method for calculating the CCFT deduction[2462] does not adhere to D.89-11-058 because the negative $51.45 million is not the amount on record in PG&E's Commission-adopted prior year summary of earnings. The impact of complying with D.89-11-058 would be an approximately $150 million taxable income difference (which equates to roughly $31.5 million-dollar lower Test Year revenue requirement).[2463] PG&E provides no authority for deviating from D.89-11-058. The Commission finds that an actually adopted prior-year CCFT rather than an estimated CCFT more accurately reflects this ratemaking deduction and is consistent with the "flow-through" method adopted for all utilities in D.89-11-058. Accordingly, for the CCFT deduction amount in 2023, the Commission adopts the 2022 CCFT amount of $109.081 million on the record from PG&E's adopted 2022 attrition tables from the last GRCs.[2464]

In addition, the Commission requires PG&E to file a Tier 1 Advice Letter providing the adopted CCFT amount for 2026 so that the prior-year adopted

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[2460] D.89-11-058, COL 2.

[2461] D.89-11-058, OP 4.

[2462] RT, Vol. 10 at 1805.

[2463] RT, Vol. 10 at 1807.

[2464] D.20-12-005, Appendix E, Table 1, line 24, column E shows $102.186 million CCFT adopted for 2022. D.19-09-025, Appendix E, Table 1, line 24, column G shows $6.895 million CCFT adopted for 2022. $109.081 million = $102.186 million plus $6.895 million.

CCFT amount is readily available to be used as the deduction amount during the next GRC. This is consistent with the "flow-through" method adopted by D.89-11-058 requiring that "...test year and attrition year CCFT estimates adopted in rates be specifically defined and made available to the Commission staff responsible for putting together the federal income tax estimates for the following attrition or test year..."

10.3. Working Cash Forecast (Capital)

PG&E requests a 2023 working cash forecast of approximately $1.633 billion as a capital component of electric distribution, gas distribution, gas transmission and storage, and electric generation rate base, as follows:[2465] (1) $948 million for electric distribution, (2) $234 million for gas distribution, (3) $138 million for gas transmission and storage, and (4) $362 million for electric generation.[2466] Within the framework of utility ratemaking, working cash is a capital component of a utility's authorized rate base and is provided by shareholders to meet utility day-to-day operations and expenditures until revenues are collected.[2467] Working cash typically consists of (1) operational cash, or amounts needed for day-to-day operations; and (2) amounts used to pay operating expenses in advance of receiving customer payments for those expenses.[2468] These amounts are included in rate base to compensate shareholders for the commitment of funds they provide to finance these requirements.[2469]

[2465] PG&E Ex-10 at 14-1 and 14- 17 (Table 14-2).

[2466] PG&E Ex-10 at 14-1.

[2467] PG&E Opening Brief at 812, *citing to* D.20-07-038 at 13.

[2468] PG&E Ex-10 at 14-1.

[2469] PG&E Opening Brief at 813.

PG&E's states that its method of computing its working cash requirement aligns with CPUC Standard Practice U-16-W[2470] and is generally consistent with the methods used in previous PG&E GRCs.[2471] PG&E addresses customer deposits with working cash because customer deposits are linked to working cash in Standard Practice U-16, where the formula is as follows:

> Working Cash = Required Bank Balances + Special Deposits and Working Funds + Other Receivables + Net Prepayments + Deferred Debits Less: Working Cash Capital not Supplied by Investors + Goods Delivered to Construction Sites + Accrued Vacation + Difference between lag in collections and lag of expense payments.[2472]

PG&E states that, consistent with prior Commission decisions, customer deposits have been excluded as a rate base item from PG&E's showing on working cash.[2473] PG&E asserts that, in accordance with D.14-08-032 and D.19-12-056, interest bearing customer deposits are treated as a source of long-term debt and are included in PG&E's capital structure for ratemaking purposes.[2474]

Cal Advocates and TURN object to PG&E's requested increase in working cash. TURN states that PG&E's request for nearly $1.7 billion in working cash is approximately a 43% increase from its 2020 GRC request and proposes a

[2470] On August 15, 2023, Official Notice was taken of the Commission Standard Practice U-16-W, Determination of Working Cash Allowance, March 2016, https://www.cpuc.ca.gov/about-cpuc/divisions/water-division/wd-standard-practices. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M055/K059/55059235.PDF.

[2471] PG&E Ex-10 at 14-2.

[2472] D.20-12-005 at 262.

[2473] PG&E Opening Brief at 812-813.

[2474] PG&E Opening Brief at 812-813.

reduction of approximately $792 million to PG&E's 2023 forecast.[2475] These objections are considered below within the disputes over specific components of working cash and customer deposits: (1) forecasted level of customer deposits for 2023, (2) bank lag, (3) revenue lag, (4) expense lags associated with goods and services expenses, and (5) expense lags associated with federal and state income tax expenses.

10.3.1. Customer Deposits Forecast

PG&E forecasts an average customer deposits balance for 2023 of $81.5 million based on 2020 recorded data.[2476] Cal Advocates argues for a higher balance of $100 million based on PG&E's 2019 recorded customer deposits data because the pandemic rendered 2020 an anomalous year for customer deposits.[2477] Cal Advocates states that PG&E's recorded 2019 customer deposits were $108 million.[2478]

PG&E responds that 2019 data reflects the impact of changes in residential customer deposit collection practices and that customer deposits have continued to fall through 2021 and early 2022, which supports PG&E's forecast.[2479] PG&E further states that 2019 is not an appropriate base year because customer deposits declined starting in 2020 due to the Commission restricting customer deposits for residential customers in D.20-06-003.[2480]

[2475] TURN Opening Brief at 575-576.

[2476] PG&E Opening Brief at 814-815.

[2477] Cal Advocates Opening Brief at 445-447.

[2478] Cal Advocates Opening Brief at 446.

[2479] PG&E Reply Brief at 604-605.

[2480] PG&E Reply Brief at 604-605

The Commission finds PG&E's forecast based on 2020 recorded data is reasonable as the forecast reflects the impact of the Commission's 2020 restrictions on the collection of certain customer deposits in D.20-06-003. Accordingly, the Commission adopts PG&E's capital forecasted average customer deposits balance for 2023 of $81.5 million.

10.3.2. Bank Lag

Revenue lag is a component in the calculation of the working cash requirement that results from PG&E having to pay expenses at different times than when offsetting revenue is received from customers. PG&E's working cash requirement is estimated by a lead-lag study that includes the bank lag.[2481] The bank lag is the average number of days between the receipt of customer payments and the availability of funds in the bank.[2482] PG&E calculated a bank lag of 0.58 days based on an average number of days from the receipt of customer payment to the availability of funds in the bank.[2483] PG&E's bank lag includes an estimate that 77.2% of customer bills will be paid electronically during this rate case period (2023-2026).[2484]

Cal Advocates recommends reducing the bank lag to 0.13 days based on PG&E's estimate of bills that will be paid electronically, which Cal Advocates asserts will likely continue to grow during the rate case period.[2485] All else being equal, the dollar impact of Cal Advocates recommendation is a reduction of total working cash capital of about $8.5 million.

[2481] PG&E Opening Brief at 815.

[2482] PG&E Opening Brief at 814-816.

[2483] PG&E Opening Brief at 816.

[2484] PG&E Opening Brief at 816.

[2485] Cal Advocates Opening Brief at 396.

In response, PG&E argues that Cal Advocates' recommendation is flawed because Cal Advocates' analysis assumes that electronic payments have a zero lag and is based on speculation that electronic payments will continue to grow beyond the 77.2% relied upon by PG&E.

The Commission finds the analysis presented by PG&E regarding bank lag persuasive. PG&E's estimated 0.58 bank lag already reflects a high percentage (77.2%) of electronic payments for the rate case period (2023-2026).[2486] Accordingly, the Commission adopts PG&E's forecast for bank lag of 0.58 days.

10.3.3. Revenue Lag

PG&E estimates a revenue lag of 48.66 days based on the method outlined in Standard Practice U-16, which PG&E states is consistent with the method used in prior GRCs.[2487] PG&E also uses 2020 net outstanding revenue collection data.[2488]

TURN recommends adopting a revenue lag forecast of 46.92 days based on the average of the three prior base year revenue lag forecasts (2017, 2020 and 2023), which supports an approximate reduction of $83.12 million in PG&E's overall working cash request. TURN contends that the additional data provides a better basis for the 2023-2026 forecast because the 2020 data includes the unusual social and economic circumstances related to the pandemic, including the higher arrearages from 2020.[2489]

In response, PG&E states that TURN's forecast methodology is flawed for the following reasons: (1) TURN ignores data showing that the revenue lag based

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[2486] PG&E Reply Brief at 604-605.

[2487] PG&E Opening Brief at 817.

[2488] TURN Opening Brief at 576-577.

[2489] TURN Opening Brief at 152-154.

on 2020 data is not abnormally high, as the average revenue lag for the years 2016-2019, prior to the Covid pandemic, was 48.82 days, which is higher than PG&E's estimate for 2020; (2) despite TURN's deployment of arrearage data for 2019 and 2020, the revenue lag for 2019 was 52.03 days, which is higher than the 2020 revenue lag of 48.66 days that TURN claims is abnormal; and (3) TURN's proposal to base the 2023 GRC revenue lag forecast as an average of prior GRC forecasts means that TURN's revenue lag would be based in significant part on the recorded revenue lags for 2014 and 2017.[2490]

The Commission does not find either PG&E's or TURN's estimates to be persuasive given uncertainties with respect to use of 2020 data and use of recorded lags going back as far as 2014 and 2017. In the absence of a more convincing evidence, the Commission declines to adopt a change in revenue lag days. The forecast adopted for the 2020 GRC of 47.69 days falls at the midway point between PG&E's and TURN's recommendations.[2491] Accordingly, the Commission finds the revenue lag forecast of 47.69 days continues to be reasonable and adopts 47.69 days for this GRC.

10.3.4. Goods and Services Expense Lag

The goods and services expense lag is a component of working cash that involves optimizing cash flow by shortening the time for receipt of revenues from customers, while lengthening the time to pay suppliers.

PG&E states that by fully utilizing vendor credit and increasing the number of expense lag-days, a lower amount of working cash is required from ratepayers.[2492] In this proceeding, PG&E presents an estimate of the goods and

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[2490] PG&E Opening Brief at 817.

[2491] D.20-12-005 at 272-274.

[2492] TURN Opening Brief at 578.

services expense lag of 16.49 days based on its study of 471,783 invoices from 2020. PG&E supports its estimate by pointing out that, for the years 2017 through 2019, PG&E's goods and services expense lag averaged 17.24 days.[2493]

TURN opposes PG&E's estimate and recommends a goods and services expense lag forecast of 36.67 days. In support, TURN states that the industry cash management best practice for an average goods and services expense lag is even longer, at 45 days.[2494] TURN also states that its proposal of 36.67 days is consistent with the average of authorized expense lag days in the most recent rate cases.[2495] According to TURN, a goods and services expense lag of 36.67 days results in a reduction of approximately $182 million in PG&E's working cash request.[2496]

In response, PG&E claims that TURN's proposal for a longer goods and services expense lag of 36.67 days would harm vendors by making them bear the burden of working cash. Further, PG&E states that shorter payment lags are more appropriate as they reflect discounts or other favorable terms with its vendors.[2497] PG&E also disputes the accuracy of TURN's data.[2498]

The Commission finds PG&E argument unpersuasive that vendors will suffer harm from a longer goods and expense lag than the 16.49 days recommended by PG&E. Moreover, the Commission finds convincing TURN's recommended expense lag of 36.67 days because this expense lag is consistent

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[2493] PG&E Opening Brief at 817-818.

[2494] TURN Opening Brief at 577.

[2495] TURN Opening Brief at 578 to 581, *citing to* D.19-09-051 at 658, 663 and D.21-08-036 at 495-496.

[2496] TURN Opening Brief at 578-581.

[2497] PG&E Opening Brief at 818-819; Reply Brief at 606-607.

[2498] PG&E Opening Brief at 818-819 and Reply Brief at 606-607.

with the goods and services lag authorized by the Commission for other similarly situated utilities. Accordingly, the Commission adopts a goods and expense lag of 36.67 days for this GRC.

10.3.5. Federal and State Income Tax Lags

Parties do not dispute that Standard Practice U-16 should be used to calculate the resulting working cash adjustment. PG&E proposes that the federal and state income tax expense lags be 48.66 days, which is equal to PG&E's estimate for the revenue lag. PG&E states that its proposal will ensure that the working cash calculation will not provide a secondary benefit to ratepayers that belongs to shareholders relative to wildfire claims.[2499] In support, PG&E cites to OII 24 (the Commission's income tax investigation) and contends that the tax benefits of using net operating losses caused by wildfire claims to reduce income taxes should accrue to shareholders because the wildfire claims were paid by shareholders. In further support, PG&E projects that deductions from taxable income due to claims paid by PG&E to wildfire victims in prior years have created net operating losses that can be carried forward and applied to taxable income in future years to reduce PG&E's income taxes, including in 2023.[2500] Thus, while PG&E initially proposed a federal income tax lag of 86.28 days and a state income tax lag of 75.90 days, PG&E revised its proposal to 48.66 lag days for federal and state after taking into account its current tax situation, including net operating losses.[2501]

TURN recommends adopting a federal income tax expense lag of 292 days and a state income tax lag of 365 days based on PG&E's historical record of rarely

[2499] PG&E Opening Brief at 819-823.

[2500] PG&E Opening Brief at 819-823.

[2501] PG&E Opening Brief at 819-823.

making actual cash tax payments since 2010 and its forecast for paying minimal or no cash tax payments for this GRC cycle.[2502] In addition, TURN cites to SCE's recent GRC decision D.21-08-036 where the Commission adopted 365 lag days for state and federal income taxes because, similar to PG&E, SCE had not made cash tax payments for federal and state income taxes in quite a number of years, and would not be a cash taxpayer during the forecasted GRC cycle. TURN makes an adjustment to reduce the 365 federal tax lag days by 20 percent to account for PG&E's assertion that recent tax net operating losses will only offset 80 percent of PG&E's taxable income.[2503]

In response, PG&E argues that TURN's calculation is invalid because it confuses cash accounting and accrual accounting because TURN's calculation assumes that income tax payments are due each day, but in reality, cash income tax payments are required to be remitted quarterly.[2504]

Cal Advocates recommends adoption of a 90-day federal income tax lag that it contends is rate neutral and consistent with Commission precedent for PG&E. In support, Cal Advocates states that PG&E's initial application assumed a 90-day expense lag for current federal income taxes, consistent with its methodology in its prior two GRCs.[2505] Cal Advocates does not present a recommendation for PG&E's state income tax lag.[2506]

In response, PG&E states that its initial calculations were incomplete and did not take into account the extensive analysis of Net Operating Losses and

[2502] TURN Opening Brief at 581-583.

[2503] TURN Opening Brief at 583-584.

[2504] PG&E Opening Brief at 822.

[2505] Cal Advocates Opening Brief at 397.

[2506] Cal Advocates Opening Brief at 397-399.

PG&E's current tax situation. Moreover, PG&E states that Cal Advocates' 90-day lag proposal falls short because, although Cal Advocates claims that its recommendation "is an effort to replicate the tax lag that would occur if PG&E were paying taxes," PG&E notes that if it were making quarterly federal estimated income tax payments, it would produce a lag of approximately 38 days, which is very close to PG&E's recommended approach of 48.66 lag days.[2507]

The Commission finds TURN's recommendation of 292 federal income tax lag days and 365 state income tax lag days to be reasonable. TURN convincingly points out that PG&E has rarely made actual cash payments in recent years, and the same holds true for the forecasted years of this GRC.[2508] TURN also persuasively cites to SCE GRC D.21-08-036 as further support for recent Commission precedent.[2509]

Similar to the issue we have before us, D.21-08-036 considered an electric investor-owned utility's (IOUs') income tax lag days in the context of a GRC where an IOU had not made recent actual cash tax payments and held substantial net operating losses associated with wildfires that would reduce or eliminate cash tax payments through the forecasted years of the GRC. D.21-08-036 found that using 365 days for state and federal tax lag days was reasonable because SCE (like PG&E) had not paid federal income taxes for several GRC cycles, and the lack of evidence that the tax situation was going to change during the GRC cycle. Moreover, D.21-08-036 observed:

[2507] PG&E Reply Brief at 607-608.

[2508] TURN Opening Brief at 580-582.

[2509] TURN Opening Brief at 582-583.

We note that this outcome is not incompatible with OII 24. In OII 24, the Commission stated:

> In this and other instances in this decision we address general principles and adopt methods that correspond with our policy judgments. We do not intend to foreclose consideration of extraordinary solutions to extraordinary problems and will consider alternatives in appropriate circumstances.[2510]

In D.21-08-036, the Commission found that OII 24 allowed that under extraordinary circumstances, it would be appropriate for the Commission to consider tax impacts associated with events outside the rate case in forecasting income tax expense and concluded that "circumstances under which a utility has not paid federal taxes for over a decade and state taxes for over a GRC cycle constitute such extraordinary circumstances that would warrant an alternative method."[2511] PG&E's tax situation is very similar to the situation considered in D.21-08-036 since PG&E has not paid state income taxes since 2018 and federal income taxes since 2010.[2512]

Therefore, the Commission finds that PG&E's circumstances likewise constitute such extraordinary circumstances under which we may consider tax impacts associated with events outside the rate case and adopt an alternative method. As a result, the Commission finds TURN's proposed methodology and resulting 292 federal income tax lag days and 365 state income tax lag days to be reasonable and consistent with D.21-08-036 and OII 24.

[2510] D.21-08-036 at 500-501.

[2511] D.21-08-036 at 501.

[2512] TURN Opening Brief at 581-582.

10.4. Electric and Gas Distribution, Electric Generation, Gas Transmission and Storage Rate Base

PG&E is allowed to earn a rate of return on rate base components that are developed on a weighted average basis. Rate base represents the depreciated asset value of PG&E's net investments used to provide service to its customers. Rate base consists of utility plant in service, working capital, and Tax Reform Act deferrals, reduced by credits for customer advances, deferred taxes, and depreciation reserve. The Result of Operations (RO) Model incorporates the adopted forecasts for capital additions and depreciation amounts, as addressed in prior sections of this decision, in deriving the adopted rate base.[2513]

Regarding the uncontested forecasts for expense and capital expenditures for the Results of Operations in PG&E Ex-10, the Commission find those amounts reasonable. The uncontested expense and capital expenditure forecasts are set forth at Appendix A of PG&E's Opening Brief at A-17 and A-25.

11. Post-Test Year Ratemaking: Years 2024, 2025, and 2026

Post-Test Year Ratemaking (PTYR), also known as attrition year adjustments, is the ratemaking concept used by the Commission to establish a revenue requirement for the remaining years of the rate case period to provide utilities with funds needed to provide safe and reliable service to its customers, as well as an opportunity to earn the authorized rate of return during the post-test years, although the latter is not guaranteed.[2514] In this proceeding, the

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[2513] D.14-08-032 at 611.

[2514] D.14-08-032, *Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2014-2016 (August 14, 2024)* at 2 and 653; D.12-11-051, *Decision on Test Year 2012 General Rate Case for Southern California Edison Company* (November 29, 2021) at 10; PG&E Ex-24-E at 1-12, *citing to* D.12-11-051, p. 10; *Southern Cal. Gas Co. v. Public Utilities Com.* (1979) 23 Cal. 3d 470; 1979 Cal. LEXIS 210.

post-test years are 2024, 2025, and 2026. Under the Commission's recently revised Rate Case Plan, this proceeding sets the revenue requirement for a four-year rate case cycle, while in the past the Commission has set the revenue requirement for three years.[2515]

11.1. PG&E's PTYR Request

PG&E states that its 2022 authorized revenue requirement was $12.214 billion.[2516] PG&E requests a test year revenue requirement for 2023 of $15.818 billion.[2517] PG&E's 2023 revenue requirement request represents an increase of $3.605 billion over the authorized 2022 revenue requirement.[2518] PG&E requests a post-test year revenue requirement of (1) $16.743 billion in 2024, (2) $17.181 billion in 2025, and (3) $17.427 billion in 2026.[2519] Based on PG&E's requested revenue requirement for 2023 of $15.818 billion, the PG&E's post-test year increases each year are as follows: $924 million in 2024 (+5.8% over 2023), $438 million in 2025 (+2.6% over 2024), and $247 million in 2026 (+1.4% over 2025).[2520]

PG&E explains that its proposal models expense and capital revenue requirements separately, also referred to as bi-furcated.[2521] PG&E supports its separate attrition methodologies for expenses and capital-related costs on the basis that, according to PG&E, expense escalation and growth in capital are

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[2515] D.20-01-002, *Decision Modifying the Commission's Rate Case Plan for Energy Utilities* (January 16, 2020) at 28-38.

[2516] PG&E Reply Brief, Appendix A at A-1 to A-3.

[2517] PG&E Reply Brief at 615-616 and Appendix A at A-1 to A-3.

[2518] PG&E Reply Brief at 615-616 and Appendix A at A-1 to A-3.

[2519] PG&E Reply Brief, Appendix A at A-1.

[2520] PG&E Reply Brief at 615-616 and Appendix A at A-1 to A-3.

[2521] PG&E Opening Brief at 834.

separate and distinct drivers for post-test year cost growth and should be reflected in the attrition methodology accordingly.[2522] In addition, PG&E states that escalating expenses and capital-related costs separately for the post-test years allows PG&E to reflect changes in rate base, depreciation expense, and taxes in attrition year revenue requirements irrespective of expense growth.[2523] As stated above, while PG&E proposes to use specific escalation rates to support some cost categories of its attrition year request, PG&E also proposes to use a budget-based approach for other specific expense and capital cost categories.[2524] PG&E's post-test year proposal also includes modifications to the Z-factor mechanism that allows for certain rate adjustments prior to PG&E's next GRC test year for unforeseen external events.[2525] PG&E's proposal is explained in more detail below.

11.1.1. PTYR Expense

PG&E requests that its 2024, 2025, and 2026 post-test year expense costs (non-labor) be set based on one of two methods, either (1) adjusted by the S&P's IHS Markit's Utility Cost Information Service indexes (the indexes found at the September 6, 2022 Update Testimony, PG&E Ex-33), or (2) a budget-based approach for certain identified expense categories.[2526]

PG&E states that the same IHS Markit's Utility Cost Information Service indexes applied to the adopted 2023 test year expense should be used to establish a post-test year revenue requirement for 2024, 2025, and 2026 and is reasonable

[2522] PG&E Ex-11 at 1-1.

[2523] PG&E Opening Brief at 831-834.

[2524] PG&E Opening Brief at 834.

[2525] PG&E Reply Brief at 615.

[2526] PG&E Opening Brief at 841-842 and 848.

for adjusting most of its expense categories because, according to PG&E, these indexes are designed to "reflect cost increases in the goods and services PG&E procures."[2527] For certain specific cost categories, however, PG&E states that a budget-based approach is more appropriate than an index because, according to PG&E, these operating expenses are "not expected to follow a normal pattern of escalation" that would be reflected in the IHS Markit's Utility Cost Information Service indexes.[2528] For these specific operating expenses "where fluctuations can be reasonably estimated and expected to exceed $10 million," PG&E proposes the use a budget-based forecast for expense in years 2024, 2025, and 2026 to avoid a "misalignment of authorized revenues and cost of service," as follows:[2529]

(1) gas storage expense (increase based on projected inspection schedule);

(2) vegetation management expense (decrease based on projected undergrounding);

(3) Diablo Canyon Nuclear Power Plant (decrease based on closure);

(4) expenses related to the transition for non-residential customers to mandatory time-of-use rates and revised time-of-use rate periods and peak-day pricing event hour revisions (increase based on transition);

(5) healthcare and other administrative and general corporate items;

(6) wildfire liability insurance (increase); and

(7) EPSS program (increase as "new wildfire mitigation program").[2530]

[2527] PG&E Opening Brief at 835, *citing to* PG&E-11-E at 1-7.

[2528] PG&E Ex-11 at 2-7.

[2529] PG&E Ex-11 at 2-7

[2530] PG&E Ex-11 at 2-7.

PG&E does not propose changes to its post-test year labor expense escalation factors in PG&E Ex-11 because these factors are discussed in PG&E Ex-08 and determined by the Commission at Section 8, herein.

11.1.2. PTYR Capital-Related Costs

Regarding capital expenditures, PG&E proposes that the Commission establish a post-test year capital expenditure forecast based on two methodologies. Generally, PG&E proposes a methodology based on adopted 2023 forecasted test-year plant additions (2023 capital additions forecast) adjusted in the post-test years to include capital cost escalation rates by using the same index, the IHS Markit's, referred as the Power Planner.[2531] PG&E explains that the "critical aspect of this approach is applying escalation to the capital additions forecast, and then calculating the resulting revenue requirement, rather than applying escalation directly to the revenue requirement…."[2532] PG&E's request includes escalating test-year net capital additions using industry-specific capital indexes, i.e., the IHS Markit's Power Planner capital indexes.[2533] PG&E suggests that its proposal to rely on an index to escalate revenue requirement related to capital is responsive to concerns by parties, stating that this proposal "is responsive to intervenor concerns from prior General Rate Cases (GRCs) that they do not have adequate resources to review a multi-year capital additions forecast."[2534]

In addition, PG&E proposes a separate method, referred to as a budget-based approach, or "bottom-up forecast," of forecasting post-test year

[2531] PG&E Opening Brief at 835, 841, and 843.

[2532] PG&E Opening Brief at 841.

[2533] PG&E Ex-11 at 1-3 to 1-4; PG&E Ex-33 at 4-1, 4-3 to 4-4.

[2534] PG&E Ex-11 at 3-5.

capital costs for certain lines of business for 2024, 2025, and 2026 "due to uneven forecast capital additions in attrition years and/or TY capital expenditures amounts exceeding the PTY bottom-up forecast." PG&E requests that the Commission adopt a budget-based approach to the following categories:

(1) Nuclear Generation,
(2) Hydro Generation,
(3) Corporate Real Estate,
(4) Gas Storage, and
(5) Electric Distribution System Hardening, including Community Rebuild.[2535]

The table below is an excerpt from PG&E Ex-11 and sets forth PG&E's capital proposal.

[2535] PG&E Opening Brief at 834-835; PG&E Ex-11 at 3-4 and fn. 3, stating "The bottom-up forecast refers to the 2024, 2025 and 2026 capital forecast presented by the witnesses in Exhibits (PG&E-3) through (PG&E-9) of PG&E's 2023 GRC Application."

Table 11-A
Capital Additions In Attrition Years
(Thousands Of Nominal Dollars)[2536]

Line No.	Description	2023	2024	2025	2026
1	Net Adds – Proposed Attrition Capital Additions[(a),(b)]				
2	Electric Distribution	$4,257,875	$4,914,613	$5,555,095	$5,822,351
3	Gas Distribution	1,404,842	1,241,835	1,355,156	1,309,832
4	EG	472,397	228,960	328,119	512,775
5	GT&S	1,046,324	1,002,517	988,732	952,157
6	**Total (lines 2-5, and/or lines 12 and 19)**	**$7,181,438**	**$7,387,925**	**$8,227,102**	**$8,597,115**
7	Net Adds – IHS Markit Escalation[(b)]				
8	Electric Distribution (excl. CRESS and System Hardening)	$2,434,154	$2,455,381	$2,654,070	$2,559,367
9	Gas Distribution (excl. CRESS)	1,210,474	1,218,441	1,320,050	1,262,854
10	EG (excl. CRESS, Diablo Canyon and Hydro)	16,931	14,579	23,415	13,414
11	Gas Transmission (excl. CRESS and Storage)	809,275	819,537	870,301	856,608
12	**Sub-total (lines 8-11)**	**$4,470,835**	**$4,507,938**	**$4,867,836**	**$4,692,243**
13	Net Adds – Detailed Forecast[(b)]				
14	Diablo Canyon	$58,437	$38,858	$15,739	$-
15	Hydro	193,994	151,087	264,249	482,285
16	CRESS (GRC ONLY)	857,926	103,258	143,002	175,363
17	Gas Storage	144,410	171,831	101,699	73,158
18	Electric Distribution – System Hardening [(c)]	1,455,836	2,414,954	2,834,578	3,174,067
19	**Sub-total (lines 14-18)**	**$2,710,603**	**$2,879,987**	**$3,359,266**	**$3,904,872**

(a) Proposed Attrition Capital Additions equals the escalated TY net capital additions for all lines of business except for nuclear generation, Hydro, CRESS and gas storage where bottom-up forecast capital additions were used.
(b) Net capital additions reflect forecast vintage retirements for certain common and general FERC accounts.
(c) System hardening bottom-up forecast is a new category added as a result of PG&E's February 25, 2022 supplemental testimony.

In support of its "budget-based proposal," PG&E states that the Commission should adopt a methodology that includes a budget-based approach to forecasting because a methodology based on only the escalation rates found in the S&P's IHS Markit's indexes is not reasonable for a number of

2536 PG&E Ex-11 at 3-6 (Table 3-2). The figures in Table 3-2 do not reflect PG&E Ex-33, the September 6, 2022 Update Testimony and escalation adjustments addressed at Section 13, herein.

reasons. PG&E states that AB 1054 requires PG&E to exclude the first $3.21 billion (a small portion is reflected in 2023 forecast) of PG&E's wildfire mitigation plan fire risk mitigation capital expenditures from earning a return on equity after the effective date of the statute.[2537] PG&E contends that its "budget-based" proposal is necessitated by AB 1054 because otherwise the test-year revenue requirement would not provide adequate funding for vital wildfire mitigation investments it must undertake in the post-test years while earning its authorized return.[2538] PG&E presents 2023 costs that include approximately $500,000 of the amount governed by AB 1054.

11.1.3. Implementation

PG&E states that, since a goal of a PTYR mechanism adjustment is to provide a streamlined process for setting revenue requirements between GRCs, it proposes that the annual gas and electric revenue requirement changes in 2024, 2025, and 2026 adopted in this proceeding be included in PG&E's Annual Electric True-Up and Annual Gas True-Up filings.[2539] PG&E states that its proposal is consistent with current practice.[2540]

11.1.4. Modifications to Z-Factor Mechanism

Regarding the Z-factor mechanism, PG&E requests that the Commission extend authorization based on previous GRCs of the Z-factor mechanism to record material impacts on costs associated with exogeneous and unforeseen

[2537] PG&E Ex-24-E at 1-11 to 1-12; PG&E Ex-10 at 15-10 to 15-11. PG&E states that D.20_12-005 (PG&E 2020 GRC) addressed $2.13 billion of the $3.21 billion exclusion under AB 1054. Table 15-2 provides summary of the capital expenditures adding up to the AB 1054 exclusion. The remaining $1.08 billion is included in the RRQ for 2023 at 100% debt financing.

[2538] PG&E Ex-24-E at 1-12.

[2539] PG&E Ex-11 at 1-19.

[2540] PG&E Ex-11 at 1-19.

events beyond PG&E's control.[2541] PG&E requests two modifications to the existing mechanism. PG&E proposes that the Commission authorize PG&E to seek cost recovery through advice letter filing, rather than the existing application process for Z-factor matters.[2542] PG&E supports its request by stating that the Commission has approved this advice letter process for other California utilities and should approve it for PG&E as well.[2543] In addition, PG&E requests that the Z-factor mechanism also include 2023 events.[2544] PG&E explains that its request to apply the Z-factor mechanism to the test year (as well as the attrition years) is "driven by the recognition that exogenous events can take place at any time during the rate case cycle," including in the test year.[2545]

11.2. Party Positions

TURN and Cal Advocates dispute PG&E's post-test year ratemaking proposal. The Coalition of California Utility Employees supports the labor escalation rates included in PG&E's proposal.[2546] Labor escalation is not disputed and is addressed in Section 8, herein. The issues in dispute, including the methodology for establishing expense and capital in the post-test years, are addressed below. Overall, parties agree that adjusting the revenue requirement in the post-test years is reasonable. Parties disagree on the methodology to use to implement these adjustments and the amount of these adjustments.

[2541] PG&E Ex-11 at 1-4.

[2542] PG&E-11 at 2-4 to 2-5.

[2543] PG&E Reply Brief at 615.

[2544] PG&E Ex-11 at 1-4, *citing to* D.20-12-005 at 409, stating "We also have no issues with tracking Z-Factor events that may occur during the TY consistent with D.19-09-051."

[2545] PG&E Ex-24-1 at 1-26.

[2546] CUE Opening Brief at 34-36.

Cal Advocates recommends an approach for post-test year ratemaking, with a decreasing revenue requirement for the attrition years, as follows: 2024 of $13.6 billion; 2025 of $13.5 billion; 2026 of $13.3 billion.[2547] Cal Advocates' proposal includes post-test year revenue increases of 3% per year (based on the Consumer Price Index plus 90 basis points) for 2024, 2025, and 2026 for Electric Distribution, Gas Distribution, and Gas Transmission & Storage.[2548] In support of its general proposal, Cal Advocates also states that 3% is consistent with recent Commission decisions in similar proceedings.[2549] Cal Advocates does not oppose PG&E's specific budget-based expense (not capital) proposals for the following areas:

(1) Gas Storage expense,

(2) Diablo Canyon Nuclear Power Plant (a reduction in expense),

(3) expenses related to the transition for non-residential customers to mandatory time-of-use rates,

(4) Nuclear Generation, and

(5) Hydro Generation;[2550] and

(6) Electric Generation.[2551]

Cal Advocates also supports the post-test year expense adopted by the Commission in D.23-01-005, the decision in this proceeding that approved the settlement regarding PG&E's Wildfire Liability Insurance. In contrast to PG&E's request, Cal Advocates does not support expense adjustments to Vegetation

[2547] Cal Advocates Opening Brief at 472.

[2548] Cal Advocates Opening Brief at 475.

[2549] Cal Advocates Opening Brief at 470.

[2550] Cal Advocates Opening Brief at 470.

[2551] Cal Advocates Opening Brief at 470.

Management, EPSS program, and Healthcare plus other Administrative and General Expenses.[2552] Regarding capital in the post-test years, Cal Advocates opposes PG&E's specific budget-based capital-related cost adjustments, except for two areas (also identified by PG&E): (1) Gas Storage, and (2) Electric Generation.[2553] On the topic of the Z-Factor mechanism, Cal Advocates supports PG&E's recommendation to adopt a Z-Factor mechanism with the same criteria used in PG&E's 2017 GRC, but recommends denying PG&E's request to apply the Z-Factor mechanism to 2023.[2554] Cal Advocates recommends maintaining consistency with the 2017 mechanisms and only applying the Z-Factor mechanism to the post-test years.[2555]

TURN agrees that the Commission should adjust PG&E's revenue requirement in the post-test years and presents its own proposal for these adjustments. TURN also presents an alternative proposal. TURN recommends that the Commission rely on a mechanism that escalates the test year 2023 authorized expenses by CPI and that the capital revenue requirement growth be adjusted based on two categories: (1) category 1 includes Electric Distribution wildfire mitigation activities, Diablo Canyon Nuclear Power Plant, and Gas Storage, and adjustment would be based on specific capital expenditures recommendations in this proceeding, and (2) category 2 includes capital adjustments for all other cost categories using the seven-year historical average (2015-2021) of capital additions escalated using the First Quarter 2020 IHS

[2552] CALPA Ex-16 at 20-21; Cal Advocates Opening Brief at 469.

[2553] CALPA Ex-16 at 20-21.

[2554] Cal Advocates Opening Brief at 430.

[2555] CALPA Ex-16 at 3.

Markit's indexes.[2556] Alternatively, TURN recommends a simplified approach for adjusting expense, by escalating test-year 2023 expense by CPI plus 50 basis points.[2557] TURN does not exclude any categories of expenses from its alternative expense proposal.[2558] With respect to capital adjustments, TURN's alternative proposal is the same as its primary proposal, using the two categories noted above. Even though TURN's recommendation includes the use of the IHS Markit's Utility Cost indexes (First Quarter 2021), TURN cautions against over reliance on utility-specific cost indexes because, according to TURN, excessive reliance on a utility-specific index could result in an approach that is too protective of PG&E and will likely fail to send the appropriate signals to the company to manage its operations productively between GRCs.[2559] TURN supports its recommendation stating that PG&E's proposed attrition mechanism, which provides a number of specific increases based on a budget-based approach, will ultimately be too generous to shareholders who should not be provided a guarantee of utility earnings.[2560] With respect to the Z-Factor mechanism, TURN suggests that PG&E be required to request an increase in

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[2556] TURN Ex-20 at 10-12. PG&E filed the First Quarter 2020 IHS Markit indexes on June 30, 2021 and subsequently requested to update these indexes on September 6, 2022 with the Second Quarter 2022 indexes.

[2557] TURN Ex-20 at 11.

[2558] TURN Opening Brief at 595. TURN Ex-11 at 4, TURN Ex-14 at 10, and TURN Ex-07 at 34. TURN's initial proposal aligned with PG&E in the area of certain expenses adjustments, including its recommendation to specifically adjust EPSS costs for 2024-2026, a reduction to Diablo Canyon Nuclear Power Plant expenses, and a reduction to Gas Storage expenses.

[2559] TURN Opening Brief at 596.

[2560] TURN Opening Brief at 589-590.

revenue requirement based on a Z-Factor event by filing an application, rather than the advice letter process recommended by PG&E.[2561]

In response to these recommendations, PG&E states, among other things, that the TURN and Cal Advocates recommendations will significantly underfund its operations in the post-test years and, in addition, that the proposals based on CPI are not reasonable because CPI does not measure increases in utility costs, cost of labor, or wage growth and, in addition, is not specific to California. The CPI, according to PG&E, is merely a general indicator of the increases in the cost of living throughout the United States, not an index that reflects increases in the costs of doing business as an energy utility.

11.3. Discussion

Under the Commission's Rate Case Plan for large energy utilities, PG&E is permitted to request a post-test year ratemaking adjustment to the test-year revenue requirement as part of it rate case application.[2562] The Commission has the discretion to grant or deny such requests.[2563] The utilities are not automatically provided or entitled to post-test year ratemaking adjustment to revenue requirement between rate case proceedings.[2564]

[2561] TURN Ex-13 at 27.

[2562] D.20-01-002, *Decision Modifying the Commission's Rate Case Plan for Energy Utilities* (January 16, 2020) at 8.

[2563] D.20-01-002, *Decision Modifying the Commission's Rate Case Plan for Energy Utilities* (January 16, 2020) at 40; D.21-08-036, *Decision on Test Year 2021 General Rate Case for Southern California Edison Company* (August 19, 2021) at 546.

[2564] D.21-08-036, *Decision on Test Year 2021 General Rate Case for Southern California Edison Company* (August 19, 2021) at 546.

At the same time, PG&E is entitled to an opportunity to earn its authorized rate of return in the post-test years.[2565] In evaluating proposals for adjusting the test year 2023 revenue requirement in the post-test years, the Commission balances the interest of ratepayers against the utility in determining a just and reasonable revenue requirement for post-test year periods. In this proceeding, the Commission reviewed PG&E's request together with the recommendations by parties regarding post-test year ratemaking for attrition years 2024, 2025, and 2026 and finds that certain adjustments to the 2023 test-year revenue requirement in the attrition years are reasonable. As such, the Commission adopts the post-test year ratemaking adjustment mechanisms set forth below.

11.3.1. Bi-Furcated Post-Test Year Adjustments

The Commission first considers PG&E's request to bi-furcate post-test year adjustments by treating expense differently than capital-related costs. TURN does not oppose this concept.[2566] Cal Advocates prefers a more uniform treatment of expense and capital for attrition year cost adjustment purposes but accepts some deviation.[2567]

Consistent with the Commission's recent decisions, including the August 19, 2021 decision on the test year 2021 GRC for Southern California Edison Company, D.21-08-036, the Commission finds it reasonable to treat expense and capital-related costs differently for purposes of post-test year ratemaking because expense and capital-related costs can affect revenue

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[2565] D.07-07-004 and D.20-01-002, *Decision Modifying the Commission's Rate Case Plan for Energy Utilities* (January 12, 2020) at 2, stating "The large energy utilities required to follow this schedule are Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company and San Diego Gas & Electric Company."

[2566] TURN Opening Brief at 594-595.

[2567] Cal Advocates Opening Brief at 470.

requirement differently, and adopts this practice in this proceeding.[2568] As such, the Commission adopts a bi-furcated methodology for determining expense and capital in the post-test years, 2024, 2025, and 2026.

Below the Commission addresses the specific manner in which expense and capital-related expenditures will be treated for purposes of calculating the post-test year revenue requirements for 2024, 2025, and 2026.

11.3.2. Expense Adjustments

With respect to adjusting expense categories in the post-test years, PG&E requests adjustments based on the energy utility industry IHS Markit's Utility Cost Information Service, as described above, with certain expense categories, also as described above, calculated on a budget-based approach. In contrast, Cal Advocates and TURN generally offer recommendations based on a uniform application of the CPI or a 3% increase.[2569]

The Commission has previously found that the CPI reflects the consumer retail price changes and not necessarily the projected fluctuations in the costs that energy utilities, such as PG&E, may experience. Likewise, at this point in time, the Commission finds the CPI-based recommendations presented in this proceeding do not provide a reasonable level of accuracy to project utility costs and, as a result, fail to provide PG&E a reasonable opportunity to recover costs in the post-test years. For this proceeding, the Commission finds reasonable the use of the energy-specific indexes in the S&P's IHS Markit's indexes (which is the same index that PG&E uses to escalate its expense from the recorded 2020 base year to the test year 2023) to adjust expense in the post-test years because the use

[2568] D.21-08-036, *Decision on Test Year 2021 General Rate Case for Southern California Edison Company* (August 19, 2021) at 545-546.

[2569] Cal Advocates Opening Brief at 431; TURN Opening Brief at 596.

of indexes is consistent with the Commission's historical practice for forecasting expense in the post-test years. In addition, these indexes provide a more accurate estimation of future costs for the procurement of goods and services in the utility industry than other indexes presented in this proceeding. This finding is supported by the Commission's recent decision regarding SCE's expense forecast for the post-test years in D.21-08-036, which also addressed a large energy utility GRC.[2570] In contrast, TURN's and Cal Advocates' recommended use of the CPI projects the consumer prices more broadly and has not been as widely relied upon recently by the Commission.

Regarding PG&E's request to separately adjust certain specific expense categories, as noted above, the Commission finds that PG&E's request is not consistent with the Commission's historic use of indexes to adjust the expense component of revenue requirement in the post-test years. The post-test year revenue requirements are necessarily a forecast. While theoretically the Commission could rely on a forecasted "budget-based" approach to adjusting expense categories in post-test years, the Commission's Rate Case Plan is not designed to accommodate the schedule or allocate the resources needed to review the reasonableness of the numerous specific costs embedded in a budget-based expense calculation for three years. Instead, the Rate Case Plan is largely designed to provide the time and resources for an in-depth analysis of one year, i.e., the test year of 2023. In addition, it is well-established that post-test

[2570] D.21-08-036, *Decision on Test Year 2021 General Rate Case for Southern California Edison Company* (August 19, 2021) at 546.

year rate adjustments are "not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee [a] rate of return."[2571]

In addition, in this proceeding, with a significant evidentiary record mostly pertaining to the test-year revenue requirement, the Commission is concerned that parties have not had sufficient time or opportunity to adequately analyze all the costs reflected in PG&E's budget-based proposals for 2024, 2025, and 2026. Rather, consistent with the Commission's Rate Case Plan, the parties necessarily focused their review on PG&E's test-year revenue requirement proposal, which is a large amount of information to support PG&E's request, with the additional volume of information to support PG&E's modified proposal with added undergrounding, of $15.819 billion in expense and capital expenditures, as reflected in PG&E's December 9, 2022 reply brief.

Therefore, while PG&E may be correct that, due to unique cost fluctuations within specific categories of expenses, a budget-based methodology for adjusting expense in the post-test years for some cost categories could be more accurate, this situation is to be expected within the ratemaking context. Forecasted budget-based calculations may provide more accurate forecasts, but the Commission's Rate Case Plan is not designed to accommodate the schedule or resources needed to review the reasonableness of particular costs embedded in a forecasted budget-based calculation. In addition, within the context of a rate case, the Commission does not require the utility to implement authorized forecasted budgets; a rate case proceeding is an authorized forecast and utilities are provided with discretion to implement these budgets in real time in accordance with best judgment.

[2571] D.21-08-036 *Decision on Test Year 2021 General Rate Case for Southern California Edison Company* (August 19, 2021) at 548-549.

To summarize, the Commission is not required to adopt a post-test year adjustment methodology that brings PG&E closer to achieving its target expense and rate of return goals.[2572] Rather, the Commission is required to provide PG&E an opportunity to earn its authorized rate of return during the post-test years, given the test year 2023 revenue requirement, while also balancing the interests of ratepayers.

For these reasons, the Commission finds reasonable a uniform approach to adjusting expenses across all cost categories (labor is addressed separately) for the post-test years, as recommended by Cal Advocates.

In selecting an index to adjust expense in the post-test years, the Commission finds persuasive PG&E's recommendation to rely upon the energy utility-specific indexes, which will more likely provide PG&E an opportunity to earn its authorized rate of return during the post-test years, while keeping rates reasonable and affordable for ratepayers. The energy utility-specific indexes proposed by PG&E is the S&P's IHS Markit's Utility Cost Information Service (and Power Planner for capital). PG&E filed the First Quarter 2020 IHS indexes on June 30, 2021 and subsequently requested to update these indexes on September 6, 2022 with the Second Quarter 2022 indexes. For the reasons discussed at Section 13, below, the Commission adopts the Second Quarter 2022 indexes, submitted by PG&E in its September 6, 2022 Update Testimony (PG&E Ex-33).

Accordingly, the Commission adopts the use of indexes to adjust all expense categories, an approach that aligns with the Commission's Rate Case Plan , with the exception of Diablo Canyon, where the Commission adopts a

[2572] D.13-05-010, *Decision on General Rate Cases of San Diego Gas & Electric Company and Southern California Gas Company* (May 9, 2013) at 1010-1011.

budget-based approach, consistent with Senate Bill 846.[2573] In addition, the Commission adopts an energy utility-specific index proposed by PG&E, the IHS Markit's Utility Cost Information Service, because it is the more accurate industry-specific forecast of costs in the record of this proceeding and will more likely provide PG&E with funds needed to provide safe and reliable service to customers, as well as an opportunity to earn its authorized rate of return. As discussed below, the Commission adopts the version of this index reflected in PG&E Ex-33, the Second Quarter 2022 IHS Markit's Utility Cost Information Service for expense.

11.3.3. Capital-Related Costs Adjustments

PG&E provides voluminous data to support its test year 2023 capital expenditure request, which was based on a combination of historical spending trends and budget-based forecasting. With respect to the years 2024, 2025, and 2026, PG&E does not provide the same level of detailed support, testimony, and analysis but, nevertheless, requests budget-based forecasts for the three attrition years. To adequately review PG&E's budget-based request, the Commission would require significantly more information to inform the record and adequately analyze PG&E's budget-based capital requests. We note, however, that even if PG&E had provided this additional information, the Commission's Rate Case Plan does not contemplate a reasonable time schedule within which the Commission could accomplish an analysis of four-years of financial data to adopt a budget-based approach to PG&E's post-test year revenue requirement. We address this matter above, in the discussion regarding expense. The timely

[2573] These include the following expenses for nuclear operations O&M: MWC AB, MWC AK, MWC BP, MWC BQ, MWC BR, MWC BS, MWC BT, MWC BU, MWC BV, MWC CR, MWC EO, MWC IG, MWC OM, MWC OS, in Section 5, Chapter 3.

completion of general rate cases, such as this proceeding, is a key principle of the Commission's Rate Case Plan. For this reason, the Commission is largely unable to scrutinize voluminous detailed budgets for four years of the rate case period and, in contrast, has historically deferred to an escalation index to determine a reasonable revenue requirement in the post-test year.

To promote efficient and fair consideration of a final decision by the Commission in general rate cases, the Commission has found it reasonable here to establish post-test year capital-related costs based largely on a uniform adjustment mechanism and, in this proceeding, the Commission adopts the IHS Markit's Power Planner indexes, proposed by PG&E. The Commission also finds that certain specific areas of PG&E's activities are more reasonably addressed through a budget-based approach, as explained below.

11.3.4. Capital Budget-Based Categories

Regarding the categories amenable to budgeted forecasts, the Commission finds that a certain narrow group of cost categories are unique and not appropriately projected with any available index mechanism and, therefore, a budget-based approach to adjustments is reasonable. While parties do not agree on the method to adjust this group of cost categories, they generally agree that these costs present unique challenges for the post-test year that are better addressed with discrete adjustments. Based on the Commission's review of the various proposals, the Commission finds a post-test year budget-based methodology reasonable for establishing post-test year revenue requirement for the identified capital expenditures.

For example, with regard to Diablo Canyon Nuclear Power Plant, PG&E has been directed by Senate Bill 846 to explore the possibility of limited continued operation of up to five additional years of the Diablo Canyon Nuclear

Power Plant, and the Commission has opened a proceeding to consider this matter, including related costs.[2574] Pursuant to Senate Bill 846, the cost of extended operations beyond the expiration of the current operating licenses for Diablo Canyon Nuclear Power Plant will be accounted for and reviewed in a new proceeding structured similarly to PG&E's annual Energy Resource Recovery Account forecast proceeding with subsequent annual advice letter true-ups to actual costs and market revenues from prior calendar years.[2575] All of the costs recovered in this new proceeding will be considered operating expenses and will not be eligible for inclusion in PG&E's rate base.[2576] Though this new proceeding has not yet been created, it is presently being considered in R.23-01-007, the Commission's successor proceeding to A.16-08-006, which addressed the continued operations of Diablo Canyon Nuclear Power Plant. Because significant uncertainty exists pertaining to the costs of this plant and because PG&E's request herein is based on the assumption that Diablo Canyon Nuclear Power Plant would be decommissioned, the Commission finds that the budget-based approach, which reflects continuation of the winding down of operations, is reasonable. The Commission may authorize costs related to continuing operation, as permitted by Senate Bill 846, in a separate proceeding. The revenue requirement implications of any continued operation will be addressed in that proceeding. Accordingly, a budget-based methodology, as presented by PG&E, is approved for purposes of post-test year ratemaking for

[2574] The relicensing of Diablo Canyon Nuclear Power Plant falls under the jurisdiction of the Nuclear Regulatory Commission and it could authorize up to 20 years of additional operations.

[2575] Pub. Util. Code Section 712.8(h)(1).

[2576] Pub. Util. Code Section 712.8(h)(1).

capital-related costs pertaining to the Diablo Canyon Nuclear Power Plant in the post -test years, 2024-2026.

In addition, in response to PG&E's argument, summarized above, regarding amounts excluded from wildfire-related capital, the Commission does not find PG&E argument persuasive that the directive in AB 1054 for PG&E to exclude a specific amount of its wildfire-related capital additions from earning an equity return justifies PG&E's budget-based proposal for wildfire expenditures. The Commission does not adopt a budget-based approach to post-test year ratemaking for wildfire-related costs. We confirm that all amounts that fall within AB 1054 shall be excluded from the revenue requirement calculation, consistent with the directive in that legislation.

The following specific cost categories related to capital expenditures are identified by the Commission as reasonable to adopt specific budgets for attrition years, 2024-2026.

1. StanPac (MAT 44A) in Section 3.12;
2. Gas Transmission C&P Compressor Replacements and Retirements: Los Medanos Compressor Replacement (MAT 76X) in Section 3.5.3;
3. Well Drilling (MAT 3L1) in Section 3.6.8;
4. Well Reworks and Retrofits (MAT 3L3) in Section 3.6.9;
5. Controls and Monitoring (MAT 3L5) in Section 3.6.12;
6. New Environmental Regulations Balancing Account (MWC 29) in Section 3.14.2;
7. Natural Gas and Solar Capital Expenditures (MWC 2S, MWC 2T, MWC 3A, MWC 3B, MWC 05) in Section 5.4.1;
8. Nuclear Operations Capital Expenditures (MWC 05, MWC 20) in Section 5.4.2;

9. Hydroelectric Costs (MWC 05, MWC 11, MWC 12, MWC 2L, MWC 2M, MWC 2N, MWC 2P, MWC 3H) in PG&E Ex-05, Table 1-2;
10. Corporate Real Estate (MWC 22, MWC 23) in PG&E Ex-07, Chapter 5; and
11. Wildfire System Hardening (MAT 08W) in Section 4.3

11.3.5. Implementation

PG&E shall file a PTYR adjustment by advice letter for attrition years 2024, 2025, and 2026 on or before December 1 for the upcoming attrition year. The attrition year revenue requirement and percentage adjustments for each attrition year shall be based on the authorized test year 2023 revenue requirement. PG&E shall use the specific escalation rates in the Second Quarter 2022 IHS Markit's Utility Cost Information Service and Power Planner, the utility-specific indexes set forth in Update Testimony at PG&E Ex-33 (as discussed at Section 13, below herein) together with the budget-based exceptions, to adjust its revenue requirements for the upcoming attrition years. PG&E shall file the relevant portion of those indexes and budget figures with the advice letters and specify the revenue requirement adjustment for expense and changes in capital-related costs.

11.3.6. Z-Factor Mechanism and Memorandum Account

The Z-Factor mechanism includes nine criteria described by the Commission in D.05-03-023 to identify unforeseen external events largely beyond PG&E's control but that have material impact on PG&E's costs that qualify for rate adjustments prior to PG&E's next general rate case test year.[2577]

[2577] D.20-12-005 *Decision Modifying the Commission's Rate Case Plan for Energy Utilities* (January 16, 2020) at 333; Cal Advocates Opening Brief at 439-440.

The Commission finds reasonable PG&E's uncontested proposal to adopt the Z-Factor mechanism for the attrition years, 2024, 2025, and 2026. Because the purpose of a general rate case is to provide a fairly precise forecast of the test year, the Commission does not adopt PG&E's proposal to apply the Z-Factor mechanism to the test year, 2023.

Regarding PG&E's proposal to implement adjustments to its revenue requirement based on the Z-Factor mechanism via advice letter, rather than the existing requirement that requires PG&E to file an application, the Commission finds that advice letters address ministerial matters and, since application of the Z-Factor mechanism is not simply ministerial, the Commission denies this request and directs PG&E to continue to rely on the existing process.

12. General Reports – Escalation Rates and Other Topics

PG&E supports its requested revenue requirement in PG&E Ex-12 by presenting the following information: (1) financial data for the recorded year 2020; (2) escalation forecasts; (3) electric distribution customer and sales forecasts, revenues at present rates, and illustrative rates; (4) gas customer and sales forecasts, revenues at present rates, and illustrative rates; (5) a matrix of compliance requirements discussed in the 2023 general rate case testimony; and (6) a summary of the balancing and memorandum accounts addressed in the 2020 general rate case.[2578] A brief summary of these topics follows. Section 13, herein, also addresses contested issues within the topics of escalation rates, certain decision compliance requirements, and balancing and memorandum accounts.

[2578] PG&E Ex-12 at 1-1.

Regarding financial data for the recorded year 2020, PG&E explains that, in terms of significant events, on July 1, 2020, PG&E emerged from Chapter 11. PG&E states that, for more information regarding the Chapter 11, interested parties should refer to PG&E's Securities and Exchange Commission Form 10-Q for the quarter ended June 30, 2020, and the Form 10-K for the year ended December 31, 2020.[2579]

Regarding escalation forecasts, PG&E presents the cost escalation rates used to reflect the effect of inflation on PG&E labor, non-labor operations and maintenance, and Administrative and General expenses for the forecast period 2023-2026.[2580] PG&E requests that the escalation rates be accepted, in their entirety, as reasonable forecasts and adopted by the Commission for use in determining PG&E's 2023 revenue requirement and annual post-test year adjustments.[2581] PG&E explains that in its June 30, 2021 Application (and its March 10, 2022 Amended Application) it relied upon escalation rates from relevant market data and contractual agreements for labor; and the Power Planner series from IHS Markit's First Quarter 2020 Utility Cost Information Service forecast for other costs.[2582] No party contested PG&E proposal to rely on First Quarter data. PG&E modified its escalation rates on September 6, 2022, when it submitted Update Testimony. TURN contests aspects of PG&E's request to rely on modified escalation rates, and the Commission addresses this dispute at Section 13, below.

[2579] PG&E Ex-12 at 2-2.

[2580] PG&E Ex-12 at 3-1.

[2581] PG&E Ex-12 at 3-1.

[2582] PG&E Ex-12 at 3-2.

PG&E also explains that, as a result of this proceeding, the Commission will adopt revised revenue requirements for the 2023 test year for electric distribution and utility generation and PG&E provides examples of the potential changes in electric rates that result from the proposed requested changes in revenue requirements in this proceeding.[2583] PG&E requests that rates implemented by this decision be consolidated with other rate changes and implemented as soon as practicable once a final decision is issued.[2584]

Table 12-A: [2585]
Summary Of The 2023 GRC Request
(Millions Of Dollars)

Line No.	Description	2022 Application As of 6/30/2021	2022 Adopted As of 12/31/2021	2023 Application As of 6/30/2021	2023 Proposed As of 12/31/2021	Application Difference from Adopted As of 6/30/2021	Difference from Adopted As of 12/31/2021	Application Revenue Requirement Change as % As of 6/30/2021	Revenue Requirement Change as % As of 12/31/2021
		A	B	C	D	E	F	G	G
1	Electric Distribution	$5,514	$5,641	$8,171	$8,229	$2,657	$2,588	48.2%	45.9%
2	Gas Distribution	2,321	2,401	2,870	2,864	550	463	23.7%	19.3%
3	Electric Generation	2,404	2,483	2,431	2,405	26	(78)	1.1%	(3.2%)
4	GT&S	1,662	1,689	1,989	1,841	327	152	19.7%	9.1%
5	**Total GRC**	**$11,901'"**	**$12,214""'**	$15,461	$15,339	$3,560	$3,125	29.9%	25.6%

(a) The $11,901 million represents 2022 authorized GRC and GT&S revenues, updated for the cost of capital as authorized in Decision (D.) 19-12-56 and approved Separately Funded projects rolling into *the* 2023 GRC; Table 17-2 for details.

(b) The $12,214 million represents the 2022 authorized GRC and GT&S revenues, updated for all tariff changes effective as of January 1, 2022, per the Energy Rate case Plan, adopted in D.07-07-004 and subsequently modified in D.1412 025, cost of capital as authorized in D.19-12-056 and approved Separately Funded projects rolling into the 2023 GRC, *see* Table 17-2 for details.

[2583] PG&E Ex-12 at 4-1 (fn. 2), PG&E states that "The currently effective revenue allocation and rate design methods were approved by Decision (D.) 18-08-013 in PG&E's 2017 General Rate Case (GRC) Phase II proceeding, and by D.15-07-001 in the Rulemaking on Residential Rate Reform. Actual rate changes resulting from the revenue requirement changes adopted in this proceeding will be implemented pursuant to the methods adopted by D.21-11-016 in Phase II of PG&E's 2020 GRC (Application (A.)19-11-019), and by D.15-07-001 or subsequent decisions related residential rate design."

[2584] PG&E Ex-12 at 4-2 and 4-10 (Table 4-5).

[2585] PG&E Ex-10 Table 17-1 at page 17-2.

Regarding gas customer and sales forecasts, revenues at present rates and illustrative rates, PG&E requests to implement the GT&S revenue requirements and capacity forecasts adopted in this proceeding concurrent with the throughput forecast, backbone load factor, and Cost Allocation and Rate Design methodologies adopted in A.21-09-018, PG&E's pending 2023 GT&S/Cost Allocation and Rate Design proceeding filed on September 30, 2021.[2586] PG&E states that within 60 days of decisions in both this proceeding and its 2023 GT&S/Cost Allocation and Rate Design, PG&E will submit a Tier 2 advice letter to update the allocations of non-GT&S rate elements, including distribution rates, for the newly adopted throughput and billings forecasts.[2587] PG&E further states that, upon Commission resolution of that Tier 2 advice letter, PG&E will seek to implement the updated end-user rates as soon as practicable. The rate changes to recover the change to Public Purpose Program Surcharge CARE Discounts will be implemented as part of the following October 31 annual filing of PG&E's Gas Public Purpose Program Surcharge (G-PPPS) Tier 2 advice letters. Those changes will go into effect the following January 1.[2588]

Lastly, PG&E presents its existing balancing and memorandum accounts. PG&E requests that the Commission adopt the following proposals:

> "1) Continue recovering adopted base revenue requirements through existing revenue adjustment mechanisms;

[2586] PG&E Ex-12 at 5-2.

[2587] PG&E Ex-12 at 5-3 and fn. 8, *citing to* D. 19-10-036 at 82 (OP#2).

[2588] PG&E Ex-12 at 5-3.

2) Continue the currently adopted operation of the following existing GRC-related mechanisms: TMA, OCMA, GSRRMA, L407MA, NERBA, BCA, MEBA, RBA, and DSIMA; …;[2589]

4) Modify the TIMPBA to allow for two-way balancing account treatment up to 135 percent of adopted amounts;

5) Modify the AMCDOP to remove obsolete subaccounts;

6) Modify the VMBA to increase the threshold for reasonableness review from 120 percent to 125 percent of adopted amounts and to record tree mortality costs in the Main Account;

7) Modify the ZFMAs to change the recovery process from an application to an advice letter;

8) Update the percentages used in the DOELBA to allocate proceeds to Utility Generation and Nuclear Decommissioning;

9) Modify the HLBA to Include Pre-2012 Settlement Agreements;

10) Modify the Distribution Investment Deferral Framework Administrative Cost Memorandum Sub-Account in the DERDDA to include incremental costs above adopted amounts for future review and approval by the Commission;

11) Modify the TEBA to exclude Operations and Maintenance expenses included in this GRC forecast for recovery;

12) Modify the GRCMA and the GTSMA to Track Under or Over Collections Related to delayed implementation of future GRC proceedings;

13) Modify the RTBA-E to: (1) Separate coverage caps for wildfire ($1.0 billion) and non-wildfire ($700 million) liability coverage. PG&E proposes to obtain $1.0 billion of wildfire liability coverage through a combination of insurance from third-parties' and self-insurance; (2) Track available

[2589] PG&E Ex-12 at 7-28, PG&E modified its request in its March 10, 2022 Amended Application to remove the following request: "3) Approve as reasonable the recorded balances as described in testimony in the ACCUMA, DRPTMA, FRMMA, WMPMA, CDGSWMA, DBSMA, GSBA, GSRRMA, L407MA, TIMPMA, CDPMA, MCOPPMA, ILIMA, and ICDAMA".

self-insurance coverage in the Self-Insurance Coverage Subaccount. Allow purchases of self-insurance will continue to accumulate in this subaccount until the balance of available self-insurance coverage reaches $1 billion, at which point PG&E will file a Tier 2 advice letter requesting to reduce or eliminate the adopted self-insurance and/or third-party insurance funding. PG&E will include in the advice letter a proposal to return any unspent funding in this subaccount that results once purchases of $1 billion of self-insurance coverage is reached; (3) Allow self-insurance to be funded exclusively through CPUC-jurisdictional, retail rates for the 2023 GRC period. PG&E will pursue recovery of self-insurance costs from wholesale customers through the FERC process over the course of the 2023 GRC period. To the extent PG&E is successful, the costs recovered will be credited back to retail customers through the RTBA; (4) PG&E proposes the balances in the Non-Wildfire Liability Insurance Section of RTBA-E subaccounts be allocated between the electric distribution and generation functions like how the adopted amounts are allocated and the balances in the RTBA-G subaccounts be allocated among the gas distribution, backbone transmission, local transmission, and storage functions like how the adopted amounts are allocated; (5) Add GT&S amounts to RTBA-G now that those functions are consolidated with the GRC; and (6) Modify the structure of the existing subaccounts in the RTBAs to implement these changes;

14) Modify the WMBA to increase the threshold for reasonableness review from 115 percent to 125 percent of adopted amounts;

15) Modify the GSBA to allow true-up of the balances in rates annually upon review and approval of costs through a tier 2 advice letter;

16) Modify the CFCA and NCA to remove reference to Los Medanos depreciation and decommissioning and continue recovery of these costs for Pleasant Creek as part of PG&E’s updated NGSS;

17) Establish new two-way CESTLBAs;

18) Establish a new HCMA; and

19) Discontinue the following accounts: TIMPMA, ECABA, CDPMA, DBSMA, CGMA, BGSDBA MCSRBA, HTBA, ACBA, ICBA, PSBA, MCOPPMA, ILIMA, ICDAMA, RCAMA, ACIBA, RCPMA, CPBA, ILIBA, LMMA, RBAMA, NRCRBA, DCRBA, and the CDGSWMA."[2590]

The Commission addresses these topics below.

12.1. Escalation Rates

Whereas PG&E had requested to use Second Quarter 2022 IHS Markit's Utility Cost Information Service and Power Planner indexes for purposes of adjusting the base year of 2020 to the test year of 2023, the Commission finds it reasonable to grant 25% of the increase in IHS escalation rates associated with PG&E's September 6, 2022 Update Filing. The Commission addresses escalation rates for purposes of establishing the test-year and the post-test years at Section 13, below.

12.2. Compliance with Prior Commission Decisions

Regarding various compliance matters and Commission directives, PG&E states that the Commission required PG&E to demonstrate compliance with 86 individual items from legislation and/or prior decisions.[2591] PG&E states that it demonstrated its compliance with each requirement in its opening testimony and workpapers and summarized the action required, a reference to the requirement, and the compliance item in a table, referred to as the Reporting and Compliance

[2590] PG&E Ex-12 at 7-28 to 7-30.

[2591] PG&E Ex-12 at 6-1 to 6-13.

Items.[2592] PG&E requests Commission approval to discontinue one reporting requirement because, according to PG&E, it is "no longer necessary."[2593]

In support of its request, PGE& states that, in D.15-04-024, which is a decision issued in the San Bruno Explosion and Fire Orders Instituting Investigations (I.12-01-007, I.11-02-016, I.11-11-009), PG&E was ordered to submit a detailed accounting to the Commission of all entries to the Shareholder-Funded Gas Transmission Safety Account (SFGTSA) as an information-only filing.[2594] PG&E further explains that it is still required to submit a final accounting to the Commission within 180 days of the date when the SFGTSA is exhausted.[2595] PG&E explains that in 2016, the Commission issued D.16-12-010, which finalized the ratemaking treatment of the $850 million (safety-spend) penalty assessed in D.15-04-024 related to gas pipeline safety enhancements.[2596] According to PG&E, the decision approved a list of safety programs and required PG&E to track expenditures for these programs in a shareholder-funded account, the

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[2592] PG&E Ex-12 at 6-2 to 6-13 (Table 6-1); PG&E Opening Brief at 857.

[2593] PG&E Opening Brief at 858.

[2594] PG&E Opening Brief at 858, referring to D.15-04-025, *Decision on Fines And Remedies to be Imposed on Pacific Gas and Electric Company for Specific Violations in Connection with the Operation and Practices of its Natural Gas Transmission System Pipelines* (April 9, 2015) at 101: "When both sub-accounts have been fully utilized (i.e. PG&E's spending obligations have been exhausted), PG&E shall submit a final accounting to the Commission, as an information-only filing, to be served on all Relevant Parties. This final accounting shall be filed within 180 days of the date when the Shareholder-Funded Account was exhausted. This final accounting may be combined with PG&E's annual information-only filing if this timing requirement can be met. Thereafter, the independent auditor shall prepare a final audit and serve its audit report on all Relevant Parties. Thereafter, PG&E shall file an advice letter to close out the Shareholder-Funded Account, with service on all Relevant Parties."

[2595] PG&E Opening Brief at 858.

[2596] PG&E Opening Brief at 858, referring to D16-12-010, *Decision Regarding $850 Million Penalty Allocation for Pacific Gas and Electric Company for Gas Pipeline Safety Enhancements* (December 1, 2016).

SFGTSA.[2597] For years 2015 to 2018, PG&E states it achieved safety spending on all capital programs except for six, on which PG&E collectively spent approximately $30 million less than the amounts the Commission allocated to those programs. PG&E proposes to record $30 million towards the Inoperable and Hard to Operate Valves program (addressed in Gas Operations PG&E Ex-03, Ch. 5)) and "eliminate the associated report of account activity required by the Commission."[2598]

The Commission finds PG&E request to "record $30 million" in capital towards the Inoperable and Hard to Operate Valves program" reasonable as PG&E's request directs funds towards a known safety concern in a timely manner during this rate case period (2023-2026). The Commission will decrease the capital expenditure revenue requirement authorized for 2023 for the Inoperable and Hard to Operate Valves Program to reflect this shareholder contribution. The Commission denies PG&E's request to "eliminate the associated report" on the basis that the report continues to serve the purpose of regulatory oversight of PG&E's use of funds directed in the Commission investigation in I.12-01-007, I.11-02-016, I.11-11-009. Furthermore, at this juncture, PG&E is directed to commence work with the independent auditor to finalize the audit and file an advice letter to close this account.

12.3. Balancing Accounts and Memorandum Accounts

For reference, Appendix B in PG&E's Opening Brief lists all uncontested memorandum and balancing accounts. Appendix C in PG&E's Opening Brief

[2597] PG&E Opening Brief at 858.

[2598] PG&E Opening Brief at 858.

lists all contested memorandum and balancing accounts. The Commission addresses the positions of parties more broadly on the use of balancing and memorandum accounts within the context of ratemaking. TURN and PG&E raise this issue. Their arguments do not completely align, but both agree that the Commission is over relying on these accounts.

TURN recommends that the Commission comprehensively review and modify balancing and memorandum accounts to better protect ratepayers from costs never demonstrated to be reasonable, to improve the utility's cost control incentive, and to promote transparency in the regulatory process.[2599] TURN urges the Commission to use this proceeding to address a number of issues regarding how current and proposed ratemaking practices for PG&E rely on balancing and memorandum accounts and states: "With PG&E's proposals in this GRC, the annual amount of such unreviewed costs that exceed the adopted forecast but are below the 'reasonableness review threshold' levels PG&E has proposed could exceed hundreds of millions of dollars each year, as TURN's testimony illustrated.[2600] TURN also points to more negative repercussions of a

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[2599] TURN Opening Brief at 605-606.

[2600] TURN Opening Brief at 605-606 (fn. 1805), *citing to* TURN Ex-13 at 13-15. "For the Vegetation Management Balancing Account (VMBA), PG&E's proposed spending of approximately $1 billion per year would be subject to a 25% "threshold," meaning PG&E could recover an additional $200-$250 million of spending each year without any further demonstration that the additional amounts were reasonable for ratemaking purposes. Similarly, the 35% "threshold" PG&E proposes for the Transmission Integrity Management Program Balancing Account (TIMPBA) could entail $100 million of additional spending each year for which there would be no required showing of reasonableness. And the Wildfire Mitigation Balancing Account (WMBA), with forecasted spending of $404.5 million of O&M and $1.715 billion of capital expenditures each year, would be subject to a 25% "threshold" that translates to the potential of an additional $101 million of O&M expense and $425 million of capital expenditures each year, again with no required showing of reasonableness of those incremental costs. The Risk Transfer Balancing Account (RTBA), for which there was no upward limit during the 2020 GRC period,

Footnote continued on next page.

regulatory policy that relies heavily on these accounts, and to diminished transparency in ratemaking and reduced utility incentive to control costs,

> "Current balancing accounts, particularly those with "reasonableness thresholds," reduce if not eliminate the utility's cost control incentive. As the Commission has previously recognized, reliance on two-way balancing accounts serves to "allow PG&E to seek recovery for cost overruns and does not encourage PG&E to seek reasonable costs." And with the growth of the number and magnitude of balancing and memorandum accounts, a larger and larger share of PG&E's operations and costs are insulated from the cost discipline that is a hallmark of forecast-based ratemaking. In an era of growing attention to affordability issues for essential utility service, the Commission should recognize the inconsistency of providing the utility with such near-automatic increases."[2601]

TURN points to the perennial issue of pole replacement as an example of how these accounts distort the regulatory process, explaining that PG&E has been permitted to record costs for pole replacement in the WMBA and avoid meaningful regulatory review below the reasonable cost set in PG&E's 2020 general rate case.[2602] TURN urges the Commission to "rein the practices in to achieve a more reasonable and balanced approach."[2603]

PG&E agrees that serious drawbacks exist in a policy of overreliance on memorandum and balancing accounts, stating: "Excessive use of balancing and memorandum accounts interferes with general ratemaking principles of

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served as the vehicle for PG&E to recover $734.3 million of above-authorized costs through the end of 2021, suggesting a cumulative amount of $1 billion of unreviewed by recoverable insurance costs by the end of 2022."

[2601] TURN Opening Brief at 605.

[2602] TURN Opening Brief at 608.

[2603] TURN Opening Brief at 609.

providing flexibility to shift funds as needs change during a GRC funding cycle."[2604] PG&E further states:

> Balancing accounts should not be used to recover routine, ongoing costs of operations where there are limited factors beyond a utilities control that can impact the forecast and the costs associated with the program are not material. Balancing accounts are not intended to serve as oversight of program activities. PG&E's revenue requirements are subject to extensive compliance and reporting requirements to verify that adopted revenues are used in a manner authorized by the Commission.[2605]

The Commission agrees that overreliance on memorandum and balancing accounts does not promote optimal utility ratemaking. Within this context, the Commission further finds that PG&E is requesting substantial and substantively significant revisions to numerous accounts in this proceeding and that additional time is needed to fully review most of PG&E's proposals. With respect to unopposed requests by PG&E to close balancing accounts and memorandum accounts, the Commission grants these requests, as closing accounts will promote transparency and simplicity in regulation and the requests are unopposed. However, the Commission denies PG&E's requests to modify any continuing accounts and PG&E may propose these changes in a separate proceeding.

13. Update Testimony – PG&E Ex-33 September 6, 2022

PG&E submitted Update Testimony on September 6, 2022 (PG&E Ex-33) and proposed several changes to the data it used to calculate its requested revenue requirement for the test year, 2023, and for the post-test years, 2024,

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[2604] PG&E Opening Brief at 859.

[2605] PG&E Opening Brief at 861-862.

2025, and 2026. The Commission permits utilities to submit Update Testimony, as explained in the Commission's Rate Case Plan.[2606] Recent Commission decisions on the permitted scope of Update Testimony and PG&E's request in PG&E Ex-33 are addressed below. Two aspects of PG&E's September 6, 2022 Update Testimony are contested: (1) Escalation Rates; and (2) Tax Updates. The Commission addresses these contested issues below.

13.1. Update Testimony Escalation Rates

PG&E's initial Application filed on June 30, 2021 included forecasts for expense and capital expenditures for the test year of 2023. PG&E's Application also included forecasts for attrition years of 2024, 2025, and 2026. Under traditional ratemaking, PG&E's 2023 test year forecasts for expense and capital expenditures are, at least in part, developed from a "base year." PG&E's "base year" in this rate case is 2020. PG&E's 2020 costs (base-year) are actual recorded amounts spent by PG&E in 2020. As part of developing its forecast for the test-year of 2023, the Commission authorizes PG&E to, among other things, "escalate" this 2020 base year by an index that reflects its changing costs over the time period between the base year and the test year to develop a forecast for the test year, 2023.[2607] To develop its requested revenue requirement, as presented in its initial June 30, 2021 Application, PG&E relied upon the IHS Markit's First Quarter 2020 Utility Cost Information Service and Power Planner to "escalate" its

[2606] D.20-12-005 *Decision Modifying the Commission's Rate Case Plan for Energy Utilities* (January 16, 2020) at 18.

[2607] D.20-12-005, *Decision Modifying the Commission's Rate Case Plan for Energy Utilities* (January 16, 2020) at 8. For example, PG&E states that it uses IHS Markit data to account for the effects of inflation on PG&E's expenses between 2020 and 2023. PG&E Opening Brief at 867-868.

base year of 2020 to its forecast for the test year of 2023.[2608] When PG&E submitted revised testimony on February 25, 2022 (and the related Amended Application on March 10, 2022), PG&E relied upon the same version of these indexes, the First Quarter 2020, to prepare its revised request.[2609] PG&E states that these indexes, the IHS Markit's Utility Cost Information and Power Planner, are a proprietary modeling program. PG&E further states that the IHS Markit indexes in PG&E Ex-33 include actual inflation rates for 2021 and, the indexes for 2022 are, in part, based on inflation amounts recorded in the first half of 2022 and are based on a forecast for the second half of 2022 as well as for the remaining years of this rate case period.[2610]

More specifically, PG&E used multiple IHS Markit's First Quarter 2020 Utility Cost Information Service (UCIS) [indexes] to escalate Administrative and General and O&M expenses by functional category. These functional categories are non-labor O&M for electric distribution, nuclear generation, hydro generation, fossil generation, gas distribution, and administrative. For the administrative category, the electric and gas administrative forecast indexes are weighted by the 2020 GRC O&M labor allocation factors. To avoid the

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[2608] PG&E Ex-12 at 3-2 to 3-3. More specifically, PG&E used multiple IHS Markit's First Quarter 2020 Utility Cost Information Service (UCIS) [indexes] to escalate Administrative and General and O&M expenses by functional category. These functional categories are non-labor O&M for electric distribution, nuclear generation, hydro generation, fossil generation, gas distribution, and administrative. For the administrative category, the electric and gas administrative forecast indexes are weighted by the 2020 GRC O&M labor allocation factors. To avoid the double-counting of healthcare cost escalation, the effect of healthcare cost increases is excluded from the administrative non-labor escalation rates.

[2609] PG&E's February 25, 2022 revised testimony (and the March 10, 2022 Amended Application) updated PG&E's costs to reflect changes to its wildfire mitigations forecast and incorporate a proposal to underground substantially more electrical assets during this rate case period for purposes of wildfire mitigation.

[2610] PG&E Opening Brief at 872

double-counting of healthcare cost escalation, the effect of healthcare cost increases is excluded from the administrative non-labor escalation rates.[2611]

PG&E proposes to use IHS Markit data to account for the effects of inflation on PG&E's expenses between 2020 and 2023. In PG&E's Update Testimony, PG&E updated the same rates using IHS Markit's Second Quarter 2022 Report.[2612]

The IHS Markit price indexes in PG&E's update include actual inflation rates for 2021. The rates for 2022 are in part based on the amounts recorded in the first half of 2022 and are based on a forecast for the second half of 2022 and the remaining years of the GRC period.[2613] When PG&E filed this rate case in June 2021, the twelve-month percentage change in the U.S. consumer price index (or the annual average inflation rate) was 5.4 percent. One year later, in June 2022, the inflation rate rose to 9.1 percent.[2614]

PG&E states that the update for the IHS Markit's indexes (PG&E Ex-33) should be adopted by the Commission as the escalation factors for purposes of establishing revenue requirement (2023-2026) for the following reasons: (1) PG&E is updating its earlier forecast by substituting a known and easily quantified change based on the earlier calculation method; (2) PG&E is

[2611] PG&E Ex-12 at 3-2.

[2612] PG&E Opening Brief at 867-868.

[2613] PG&E Opening Brief at 872.

[2614] The Commission proposes to take official notice of the U.S. Bureau of Labor Statistics Chart of Consumer Price Index from January 2018 to June 2023, available at https://www.bls.gov/opub/ted/2023/consumer-prices-up-3-0-percent-over-the-year-ended-june-2023.htm. Grounds exist for taking official notice of the above pursuant to Rule 13.9 of the Commission's Rules of Practice and Procedures and California Evidence Code Section 452. If a party objects to the taking official notice of this information, the party shall file and serve a motion to object within 10 days of the service of this proposed decision.

substituting a more recent forecast from the same firm that had provided the forecast underlying direct testimony; (3) PG&E did not change any previously-used forecast method or rely on a new forecast method; and (4) for decades, the Commission has consistently approved of the use of IHS escalation indexes (or those of its predecessor) in utility rate cases.[2615]

Regarding PG&E's September 6, 2022 Update Testimony (PG&E Ex-33 with the updated escalation rates), the Commission notes that it is a well-settled ratemaking principle that utilities adjust base year amounts by reliance on an index, and parties do not contest the fact that PG&E adjusted its base year 2020 amount or relied upon an index to adjust its 2020 base year to a test year 2023 forecast. Moreover, the Commission's Rate Case Plan permits utilities to "update" the index used to escalate its base year to the test year while a rate case is pending under certain circumstances, as follows: known changes in cost of labor based on contract negotiations completed since the tender of Notice of Intent, or known changes that result from updated data using the same indexes used in the original presentation during hearings; changes in non-labor escalation factors based on the same indexes the party used in its original presentation during hearings; and for known changes due to governmental action such as changes in tax rates, postage rates, or assessed valuation.[2616] The Commission permits updates, in part, because rate cases can be lengthy proceedings, spanning several years, and the Commission finds it reasonable to provide utilities with an opportunity to update a potentially stale index and present a forecast that reflects more current economic conditions.

[2615] PG&E Opening Brief at 868-869.

[2616] D.21-08-036 at 180; D.07-07-004, *Opinion Modifying Energy Rate Case Plan* (July 12, 2007) Appendix A at A-36.

No party contests that PG&E submitted its September 6, 2022 Update Testimony (PG&E Ex-33) consistent with the Commission's Rate Case Plan and in accordance with the schedule adopted by the assigned Commissioner's Scoping Memo.[2617] The Commission finds that PG&E's submission of PG&E Ex-33, the Update Testimony escalation rates, is procedurally consistent with the process adopted by the Commission Rate Case Plan. In addition, PG&E's Ex-33 includes the same index previously submitted as evidence, the IHS Markit's Utility Cost Information Service and Power Planner, but presents an updated version, the Second Quarter 2022.[2618] Because PG&E submitted the same indexes previously relied upon, the Commission also finds that PG&E's submission of these particular indexes is consistent with the Commission's Rate Case Plan.

In terms of the content of PG&E's September 6, 2022 Update Testimony, parties do not contest that PG&E is permitted to submit Update Testimony on certain narrow topics and to revise its requested revenue requirements based on more recent versions of escalation rates of the same index submitted as evidence with its Application. Based on this more recent version of the same indexes, PG&E increased its test year 2023 requested revenue requirement increase over the authorized 2022 revenue requirement from $3.125 billion (as of March 10, 2022) to $3.967 billion (September 6, 2022), an increase of $842 million.[2619]

PG&E explains that this increase, which PG&E describes as "substantial," reflects a time period of inflation in the United States economy in 2021 and 2022.[2620] The Second Quarter index presented in PG&E's Update Testimony

[2617] TURN Opening Brief at 613.

[2618] PG&E Ex-33.

[2619] PG&E Opening Brief at 857.

[2620] PG&E Opening Brief at 870.

applies to non-labor expense and capital expenditure, and not to labor.[2621] PG&E further explains that it requests authority to use the data found in the Second Quarter index (PG&E Ex-33) in its Results of Operations Model to update PG&E's 2021-2026 forecasts.[2622] PG&E explains that the Commission should not adopt escalation rates in a piecemeal fashion but that the IHS Markit's Utility Cost Information Service and Power Planner "must be adopted in their entirety to accurately escalate the 2020 base year costs."[2623] For example, PG&E suggests that the Commission should not select certain aspects (or years) of the indexes, which cover 2021-2026 and deny the use of other aspects of the index because, stating as follows:

> "The IHS Markit data in the Update must be taken as an entire comprehensive replacement for the data in the First Quarter 2020 report that PG&E submitted with its initial testimony. The First Quarter 2020 forecasts, as demonstrated by the Second Quarter 2022 IHS Markit data, does not reflect current inflation rates. Given that most of the inflationary impact occur in 2021 and 2022 in the IHS data, the Commission cannot implement the escalation factors in such a way that would ignore the actual recorded data for 2021 and 2022, and use only the lower or negative forecasted rates for the later years. The data must be taken as a whole to provide an accurate estimate of the impact of inflation during the entire 2021-2026

[2621] PG&E Opening Brief at 857; PG&E Ex-12 at 3-2; PG&E Ex-33 at 2-1. More specifically, PG&E used the IHS Markit's First Quarter 2020 Utility Cost Information Service to escalate non-labor expense by functional category. These functional categories are non-labor O&M for electric distribution, nuclear generation, hydro generation, fossil generation, gas distribution, and administrative. For the administrative category, the electric and gas administrative forecast indexes are weighted by the O&M labor allocation factors in the 2020 general rate case. To avoid the double-counting of healthcare cost escalation, the effect of healthcare cost increases is excluded.

[2622] PG&E Ex-33 at 4-3 to 4-4.

[2623] PG&E Opening Brief at 871-873.

period, including the inflationary period and, hopefully the periods of correction that follow it."[2624]

PG&E requests that the September 6, 2022 Update Testimony escalation rates for expense non-labor be accepted as reasonable and be adopted by the Commission for use in determining PG&E's 2023 test year revenue requirement. As noted above, as a result of changes in escalation rates and tax changes, PG&E's September 2022 update proposes a revenue requirement increase for test year 2023 that increased from $3.125 billion to $3.967 billion,[2625] equating to an increase of $842 million. The Update Testimony increases PG&E's requested test year 2023 revenue requirement increase by approximately 26.8% over its February 25, 2022 request and 32.4% over its 2022 authorized revenues,[2626] equating to an increase of 6.8% over its February 2022 request within seven months.

TURN recommends that the Commission establish a revenue requirement based on First Quarter 2020 data and does not support adoption of PG&E's September 6, 2022 Update Testimony escalation factors because TURN questions their accuracy and reasonableness.[2627] In terms of reasonableness, TURN makes a number of arguments.[2628] TURN notes that nothing in the Rate Case Plan requires PG&E to submit Update Testimony escalation rates. TURN also points out that the Rate Case Plan does not require the use of any specific index.[2629] In addition, TURN notes that the Rate Case Plan does not require the Commission

[2624] PG&E Opening Brief at 873.

[2625] PG&E Opening Brief at 857.

[2626] PG&E Opening Brief, Appendix H, p. H-1, Table 1.

[2627] TURN Opening Brief at 613-616.

[2628] TURN Opening Brief at 613.

[2629] TURN Opening Brief at 613.

to adopt PG&E's Update Testimony escalation rates.[2630] Regarding accuracy, TURN suggests that, due to recent unusual economic activity, the Second Quarter 2022 data presented in the Update Testimony is inherently unreliable, stating "Those escalation factors were estimated by IHS Global Insight during what is a very uncertain time in the macroeconomic economy, 'given all of the shock that has been seen to the system. Indeed, IHS Markit's Second Quarter 2022 report included significant differences in estimated escalation compared to its First Quarter 2022 report prepared three months earlier."[2631] TURN's overarching concern, however, is that the Update Testimony (PG&E Ex-33) escalation rates propose significant increases in revenue requirement, stating the "request would significantly worsen affordability and further jeopardize the ability of PG&E's customers to access essential gas and electric utility services."[2632]

TURN also questions the application of PG&E's updated escalation factors. During the September 21, 2022 hearing, TURN asked PG&E what categories of costs PG&E proposes to escalate with its updated escalation indexes or factors. TURN asked PG&E if it uses the same rate for costs that are fixed or predetermined and those that are not.[2633] PG&E's witness did not adequately explain whether or not it has different escalation rates for costs that are predetermined versus those that are not. In addition, PG&E did not provide a witness, for either its original or Update Testimony, to further describe to which

[2630] TURN Opening Brief at 613.

[2631] TURN Opening Brief at 614, *citing to* 14 RT 2644: 18 – 2645.

[2632] TURN Opening Brief at 613.

[2633] September 21, 2022 RT at 2,663:12 – 2,664:11; 2,694:27 – 2695:11.

categories of costs PG&E would and would not apply its updated escalation rates. [2634]

In its reply brief, TURN further explained that PG&E should submit data from IHS Markit Reports for the Third and Fourth Quarters of 2022.[2635] TURN also notes that post-test year escalation should be governed not by the IHS Markit Reports but instead by CPI-U.[2636]

To address TURN's concern about whether the inflation rates were accurately forecast, PG&E proposed to make available the next two IHS Markit's quarterly reports, the Third Quarter 2022 Report and the Fourth Quarter 2022 Report, and the Commission authorized PG&E to make this filing.[2637] On February 3, 2023, PG&E moved to admit PG&E Ex-84 into evidence representing Fourth Quarter IHS Markit's 2022 Utility Cost Information Service and Power Planner. PG&E did not file the Third Quarter 2022 IHS Markit's data. On May 9, 2023, a ruling was issued and the above escalation rates were admitted into evidence without opposition.

In response to TURN's other arguments, PG&E states the Commission has consistently approved of the use of IHS Markit's escalation indexes and those of its predecessor in utility rate cases for decades. However, in the past two decades, the inflation rate has been consistently low and often half the rate

[2634] September 21, 2022 RT at 2,697:11 – 2,668:2.

[2635] TURN Reply Brief at 169.

[2636] TURN Reply Brief at 169-170.

[2637] PG&E Opening Brief at 873, *citing to* RT Vol. 15, 2751:21 to 2753:13. Specifically PG&E proposed to make available the reports themselves and reproduce Table 2-1 (IHS Markit's Q2 2022 O&M Non-Labor Escalation Rates, 2021-2026) and Table 2-3 (IHS Markit's Q2 2022 Capital Escalation Rates 2021-2026) with the Q3 2022 Report data and the Q4 2022 Report Data (subject to appropriate confidentiality treatment). As permitted by the ALJ, PG&E submitted this data as a late-filed exhibit (PG&E Ex-84) by motion.

inflation reached in 2021 and 2022. During this time, the application of escalation rates to incorporate inflation rates was either uncontested (as the 2017 and 2020 GRCs settled) or did not engender scrutiny because a substantial increase in the utility's revenue requirement was not requested.[2638] No prior GRC in recent history has had an escalation update that increased the requested revenue requirement by a factor of up to a billion dollars, almost all in the test year alone.[2639] Accordingly, the Commission finds that PG&E's requested increase due to inflation in this rate case is entirely different and deserves additional scrutiny commensurate with the requested increase. It is difficult to contemplate a situation that would more reasonably demand additional scrutiny and review than the one before us here, in which the utility is requesting exceptional increases; the fact that inflation updates have generally been approved in the past does not require their blanket approval in every circumstance.

PG&E also claims that its updated escalation factors for the years 2021 to 2026 must be adopted in their entirety to accurately escalate the 2020 base year costs PG&E used to develop its 2021-2026 forecasts. As a general matter, increases attributable to inflation may be needed as the prices that PG&E pays for materials and supplies to provide safe and reliable service are similarly increasing.[2640]

However, the authorities cited by PG&E do not support the application of an entire database of modeled, proprietary data across all of PG&E's cost categories without transparent review and analysis of actual price increases for the time period in which inflation has almost doubled. We note that PG&E has

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[2638] PG&E Opening Brief at 871.

[2639] Cal Advocates Opening Brief at 4.

[2640] PG&E Opening Brief at 871.

not applied the IHS Markit indexes to all costs, as PG&E does not propose updating its operations and maintenance labor escalation rates.[2641] Given that escalation rates are based on prior rates, it is important for the Commission to thoroughly review substantial increases in escalation rates and how they are applied to produce the most accurate and reliable forecast of test year expenses.[2642] The Commission finds that PG&E has not met its burden of proof to demonstrate that the substantial increase in revenue requirement due to escalation included within its Update Testimony results in reasonable rates. The above finding is supported by the negative inference that may be drawn from PG&E's failure to explain its application of its proposed escalation rates.[2643]

The above finding is supported further by Pub. Util. Code Section 1822, which requires the Commission to "verify, validate, and review the computer models of any electrical corporation that are used for the purpose of planning, operating, constructing, or maintaining the corporation's electrical transmission system, and that are the basis for testimony and exhibits in hearings and proceedings before the commission."[2644] It is reasonable to also review the databases to which models are applied. In that regard, Pub. Util. Code Section 1822 further requires that "any database that is used for any testimony or exhibit in a hearing or proceeding before the commission shall be reasonably accessible to the commission staff and parties to the hearing or proceeding to the extent necessary for cross-examination or rebuttal, subject to applicable rules of evidence, as applied in commission proceedings." In this case, PG&E has neither

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[2641] PG&E Ex-33 at 2-1.

[2642] TURN Opening Brief at 614 – 615.

[2643] Evidence Code Sections 412 and 413.

[2644] Pub. Util. Code Section 1822(a).

presented a witness regarding the data it used to develop updated escalated costs based upon its modeled escalation rates, nor has PG&E resolved questions regarding the application of its modeled escalation rate in the Results of Operations model. Accordingly, as further addressed below, the Commission grants only 25% of the increase in IHS inflation-driven escalation rates presented in PG&E's Update Testimony.

The Commission acknowledges the impact of higher inflation in 2022 than expected when PG&E made its initial filing, but does not find that granting the full increase requested in the September 6, 2022 update filing would lead to reasonable rates under the circumstances of this proceeding. California and the nation had historically high inflation rates in 2021-2022 that had not been experienced since the early 1980s. Previous update filings were in times of more common inflation levels since then of 3% or under, and non-controversial, so an update filing requesting this level of increase is unprecedented in modern rate case decision-making. There are already extremely high expense and rate increases in this proceeding before considering the update filing. The high level of inflation in 2021-2022 has abated considerably in 2023, falling to historically normal ranges of 3% or under.

Furthermore, the Commission has grave concerns with approving what amounts to a multi-billion dollar rate increase in an update filing without the thorough level of review that accompanies the primary rate case. The Commission has recognized that the purpose of attrition mechanisms generally is to protect a utility from extraordinarily high inflation rates and unpredictable changes in the market that might jeopardize a utility's opportunity to earn its authorized rate of return.[2645] But broadly similar to the Southern California Edison GRC proceeding, the Commission has questions about approving such a large rate increase in an update filing or in the post-test years without the level of scrutiny provided to the main rate case.[2646]

Therefore, the Commission has before it a range of options, and we choose a number within the range because inflation has subsided since PG&E made its update filing in 2022. The Commission grants 25% of the increase in IHS inflation-driven escalation rates that PG&E requested associated with its September 6, 2022 update filing relative to the escalation rates submitted with its 2023 GRC Application on June 30, 2021. The increase of the September escalation rates over the initial escalation rates is reduced by 75%. The escalation applies to the 2020, 2021, and 2022 costs to escalate them to the 2023 test year and does not affect post-test year escalation rates.

The result is a modest increase in escalation over and above the initial escalation applied to 2023 before considering the update filing. This amount still protects PG&E from the impact of high inflation while keeping rates at a reasonable level during a very uncertain economic time, due to numerous factors unique to the 2021-2022 time period. In conjunction with all other increases approved in this decision, the Commission believes this result allows PG&E a fair opportunity to earn its authorized rate of return.

13.2. Updated Testimony Tax Changes

PG&E's September 6, 2022 Update Testimony includes a number of proposed adjustments related to income tax, including an adjustment to comply

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[2645] D.96-01-011, 1996 Cal LEXIS 23 at *43, *citing* to D.92497, 4 CPUC 2d 725, 770 (1980), 1980 Cal LEXIS 1024.

[2646] *See* D.96-01-011, 1996 Cal LEXIS 23 *45-*46, and D.21-08-036.

with IRS Private Letter Ruling 202211004, the inclusion in ratemaking of the new Corporate Alternative Minimum Tax, and a proposed Gas Transmission and Storage tax accounting method change. PG&E's September 6, 2022 Update Testimony also discussed newly-enacted tax credits that PG&E proposes to track in its Tax Memorandum Accounts, if applicable.[2647]

Regarding the adjustment to comply with IRS Private Letter Ruling 202211004 (PLR), PG&E explains that the PLR addressed the appropriate treatment of cost of removal (COR) with respect to the amortization of Excess Deferred Income Taxes arising from the 2017 Tax Cuts and Jobs Act corporate tax rate reduction and that in the PLR, the IRS ruled that the CPUC's approach of including COR in the computation for the return of EDIT violated IRC normalization rules that PG&E must comply with in order to avoid a normalization violation.[2648] PG&E further explains that this type of adjustment has already been approved by the Commission for pre-2023 periods through the advice letter process.[2649]

No party contested PG&E's application of the IRS directives set forth in the PLR or PG&E's proposed methodology that should bring it into compliance, allowing PG&E to avoid an IRS normalization violation. As a result, we find that PG&E should make the proposed adjustment necessary to maintain compliance with PLR 202211004 and by extension, avoid a normalization violation.

Regarding the new Corporate Alternative Minimum Tax (CMT) that was enacted as part of the Inflation Reduction Act of 2022 (IRA), PG&E describes how the CMT applies to 15 percent of Adjusted Financial Statement Income (AFSI) if

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[2647] PG&E Ex-33 at 3-3.

[2648] PG&E Opening Brief at 810.

[2649] PG&E Opening Brief at 810.

the taxpayer generates over $1 billion AFSI over a three-year period. PG&E then states that it computed the CMT based on its interpretation of the IRA and forecasts that the CMT impacts PG&E beginning in 2023.[2650] PG&E's methodology for ratemaking is to derive a simulated AFSI based on its forecasts for revenues, expenses, taxes, and depreciation and then multiply by 15% to arrive at the CMT. PG&E then adds this CMT to rate base as a deferred tax asset.

No parties to this proceeding contested PG&E's proposal regarding the CMT. Nevertheless, we are not persuaded by PG&E's proposal to include the CMT in the 2023 revenue requirement. During hearings, PG&E acknowledged that PG&E is not guaranteed to be subject to the CMT in 2023.[2651] Moreover, PG&E has not demonstrated that it has incurred over $1 billion of actual AFSI on average over a three-year period which, as mentioned above, would likely subject it to the CMT in 2023. Nor has PG&E adequately explained how its substantial Net Operating Loss position impacts the calculation of the CMT.[2652] In addition, PG&E acknowledges that there is no IRS or other taxing authority requirement to implement the CMT for ratemaking purposes.[2653] Because of the considerable uncertainty surrounding the actual applicability of the CMT to PG&E and the lack of any requirement by taxing authorities to impute the CMT for ratemaking, we decline to adopt the CMT for ratemaking purposes in this general rate case.

In support of its request regarding changes to its Gas Transmission Accounting Method, PG&E states that it has filed with the IRS an *Application for*

[2650] PG&E Ex-33 at 3-2 to 3-3.

[2651] 14 RT 2730: 16-18.

[2652] 14 RT 2730: 19 - 2731: 7.

[2653] 14 RT 2730: 11-15.

Change in Accounting Method with its 2021 federal income tax return, pursuant to the automatic change rules under Revenue Procedure 2022-14 related to tax repair deductions for gas transmission costs.[2654] PG&E states that its September 6, 2022 Update on this matter is appropriate because the topic is consistent with those topics the Commission has previously identified as permitted within a Update, "known changes due to governmental action such as changes in tax rates. . . ."[2655] PG&E explains that this change in accounting method will likely reduce revenue requirement.[2656]

TURN contends that, even though the change may reduce the utility's authorized revenue requirement for the 2023 test year and the 2024-26 attrition years, the Commission should not approve PG&E's proposed Gas Transmission Accounting Method change because: (1) PG&E's request is an inappropriate extension of Update Testimony beyond its limited purposes, and 2) the nature of the underlying request.[2657] TURN takes issue with PG&E making this change at this time because the impacts of 2021 and 2022 will benefit the utility, rather than ratepayers. TURN explains this is the result of a regulatory anomaly that has the Tax Memorandum Account (TMA) applying to general rate case ratemaking but not to GT&S ratemaking for 2021-2022. TURN recommends that if the Commission approves the proposed GT&S tax accounting change, the Commission should ensure that the benefits from this rate case period flow to ratepayers, including for years 2021-2022.[2658] PG&E responds that there is no

[2654] PG&E Opening Brief at 811.

[2655] PG&E Opening Brief at 811-812.

[2656] PG&E Ex-33 at 3-4.

[2657] TURN Opening Brief at 617.

[2658] TURN Opening Brief at 616-621.

need to revise the TMA because it will automatically capture GT&S tax law changes beginning in 2023 and asserts that because GT&S was not part of the 2020 general rate case revenue requirement, the general rate case TMA does not apply to GT&S revenue requirements before 2023.[2659]

As noted above by TURN, under the Commission's Rate Case Plan, the scope of update testimony is narrow. PG&E's proposed tax accounting change requires government action but is not a "known change due to governmental action" under the Rate Case Plan. And as further noted by TURN, PG&E admits the change is voluntary and is not required by any law or statute, nor is there any deadline by which PG&E must act in order to preserve its ability to make this elective change.[2660]

As such, the Commission finds that consideration of PG&E's Gas Transmission Accounting Method changes, as presented in the September 6, 2022 Update Testimony (PG&E Ex-33), falls outside the permitted and narrow scope of update testimony and PG&E's changes will not be reflected in the revenue requirement adopted in this proceeding.

Regarding applicability of gas transmission to the Tax Memorandum Account, we find that gas transmission was not included in the 2020 general rate case revenue requirement and thus, the Tax Memorandum Account did not apply to GT&S revenue requirements prior to 2023. As a result, the Commission declines TURN's request to apply the 2021-2022 GT&S tax accounting changes. If PG&E secures IRS approval to make this accounting change, the Commission grants PG&E's alternative request to include the proposed revenue requirement

[2659] PG&E Reply Brief at 602-603.

[2660] TURN Opening Brief at 619-620.

decreases in the TMA beginning in 2023 when Gas Transmission becomes part of the general rate case revenue requirements and confirms that the Tax Memorandum Account will apply to ensure that the appropriate benefits from this rate case period flow to ratepayers in the future.

14. Memorandums of Understanding

PG&E has entered into memorandums of understanding (MOUs) with the following four parties: the Small Business Utility Advocates, CforAT, National Diversity Coalition, and the Engineers and Scientists of California Local 20. Some of these MOUs include spending commitments by PG&E, which are uncontested. These MOUs can be found as attachments to PG&E's Opening Brief. PG&E states these MOUs are reasonable and in the best interest of customers, and requests that the Commission approve them in this proceeding.[2661] No party opposes the MOUs. The Commission finds these MOUs reasonable.

15. Track 2 of Proceeding on Balancing Accounts and Memorandum Accounts and the January 6, 2023 Settlement

PG&E's June 30, 2021 Application requested approval its revenue requirement for the rate case period (2023-2026) and also for cost recovery of amounts recorded in a number of memorandum and balancing accounts, primarily for 2019, 2020, 2021, and 2022, with some costs dating back to 2015. On October 1, 2021, the Assigned Commissioner's Scoping Memo established two tracks for consideration of PG&E's requests: (1) Track 1 would address PG&E's proposed revenue requirement for base GRC activities; and (2) Track 2 would address PG&E's proposed cost recovery for amounts recorded in the identified

[2661] PG&E Opening Brief at 875-879.

14 balancing and memorandum accounts.[2662] The Scoping Memo also determined that Track 2 would consider the recorded costs in the specified balancing and memorandum accounts prior to 2019 and through 202.

Regarding the costs presented by PG&E in the memorandum account pertaining to 2022, the Scoping Memo acknowledged that the breath of issues presented in the proceeding regarding the requested revenue requirement was already vast and, therefore, a process would be determined at a later date on whether this GRC proceeding should be extended for a longer period of time to include, perhaps, a possible third track to consider the recorded costs in balancing and memorandum accounts for 2022.[2663]

On July 22, 2022, PG&E filed a request to remove several memorandum accounts from consideration in this proceeding, and presented as part of Track 2, and to establish a reduced amount of costs for consideration in Track 2.[2664] PG&E also served revised prepared testimony and related workpapers to support its revised Track 2 request.[2665] Under PG&E's revised request in Track 2, PG&E sought cost recovery of approximately $208 million in expense and $129 million in capital expenditures, representing a total incremental revenue requirement of

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[2662] October 1, 2021 *Assigned Commissioner's Scoping Memo and Ruling* at 12. The 14 balancing and memorandum accounts as discussed at PG&E Ex-12 dated June 30, 2021, Ch.7 at 7-6 to 7-7, Table 7-2.

[2663] October 1, 2021 *Assigned Commissioner's Scoping Memo and Ruling* at 4. Later in the proceeding, the issue of whether the Commission would establish a third track. Later in the proceeding, on April 25, 2023, the ALJs issued a ruling and announced that a third track would not be initiated in this proceeding.

[2664] July 22, 2022 Pacific Gas and Electric Company's (U 39 M) 2023 GRC Track Two Request at 1.

[2665] Track 2 Prepared Testimony (PG&E Ex-80) and workpapers (PG&E-Ex-81 (July 22, 2022). On September 30, 2022, PG&E served Supplemental Testimony (PG&E Ex-82). On December 23, 2022, PG&E served errata (PG&E Ex-83) correcting the amounts requested for certain accounts.

approximately $241 million, including $3.703 million in interest for 2015-2026, to be collected over a two-year period.[2666]

The reduction reflects PG&E's removal of two memorandum accounts pertaining to wildfire mitigation activities from the June 30, 2021 Application, which PG&E described, as follows:

> PG&E removed from its Track 2 request Wildfire Mitigation Plan Memorandum Account (WMPMA) and Fire Risk Mitigation Memorandum Account (FRMMA) balances included in its original testimony (now withdrawn). PG&E will seek recovery of these costs in a future application consistent with Pub. Util. Code § 8386.4 (b) (2) which authorizes cost recovery in an application outside of the GRC 'at the conclusion of the time period covered by the [Wildfire Mitigation] plan.' The removal of WMPMA and FRMMA costs from this proceeding substantially reduces the magnitude of PG&E's requested revenue requirement for Track 2 and will allow for a more efficient review of Track 2 costs and timely decision.[2667]

PG&E also removed the California Distributed Generation Statistics Website Memorandum Account (CDGSWMA) from the proceeding, an account initially included as part of Track 1.[2668]

On December 15, 2022, PG&E filed a request in A.22-12-009 for cost recovery of approximately $1.36 billion for wildfire mitigation activities in 2021, which PG&E recorded in the Wildfire Mitigation Plan Memorandum Account

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[2666] July 22, 2022 Pacific Gas and Electric Company's (U 39 M) 2023 GRC Track Two Request at 1, and PG&E Ex-80 at 7-2.

[2667] July 22, 2022 Pacific Gas and Electric Company's (U 39 M) 2023 GRC Track Two Request at 1, *see* fn.1.

[2668] PG&E Ex-12, Table 7-2 (June 30, 2021) lists 14 accounts to be reviewed. Each of these is addressed in PG&E's Track 2 testimony, except for CDGSWMA (PG&E Ex-12, Table 7-2, line 5).

and Fire Risk Mitigation Memorandum Account, two memorandum accounts initially included as part of this proceeding.[2669]

On December 23, 2022, PG&E filed errata testimony on issues pending in Track 2 as PG&E Ex-83, which included an increase in PG&E's expense request from $205.646 million to $208.953 million, and a decrease in its capital expenditure request from $128.970 million to $128.969 million.[2670] This errata testimony also corrected an error in PG&E's calculation of the revenue requirement associated with PG&E's capital expenditure request but did not provide a revised total revenue requirement.[2671]

On November 14, 2022, Cal Advocates served its prepared testimony on PG&E's July 22, 2022 Track 2 request. No other party served testimony regarding issues within Track 2.

On December 12, 2022, parties agreed that evidentiary hearings were not needed for Track 2 issues as settlement discussions were ongoing. A December 13, 2022 ALJ Ruling, removed the evidentiary hearings schedule for Track 2 from the hearing calendar.

On January 6, 2023, Cal Advocates and PG&E filed a joint motion for approval of a settlement resolving all issues in Track 2, the *Joint Motion of Pacific Gas and Electric Company and The Public Advocates Office at the California Public*

[2669] A.22-12-009, Application of Pacific Gas and Electric Company for Recovery of Recorded Expenditures Related to Wildfire Mitigation, Catastrophic Events, and Other Recorded Costs (U39M) (December 15, 2022).

[2670] PG&E Ex-83 at 2. A note to Table 1-2 indicates that an additional approximate $3,000 reduction in capital expenditures is not included in the table, but will be reflected later. The settlement includes this reduction in its $128.966 million value as discussed below.

[2671] PG&E Ex-83 at 11-12. Table 3 at 12 shows an increase in revenue requirement from $6.026 million to $10.706 million, but the $4.680 million increase is for GSBA only, not the total Track 2 request which was $241 million originally.

Utilities Commission for Approval of a Settlement of Track 2 Issues (herein, the Joint Motion). PG&E and Cal Advocates attached their settlement to the Joint Motion, as Attachment A, *Settlement Agreement Between Pacific Gas and Electric Company and the Public Advocates Office at the California Public Utilities Commission on Track 2 Issues* (herein, the January 6, 2023 Settlement or Settlement).

On January 6, 2023, PG&E and Cal Advocates filed a motion seeking to enter exhibits into the record pertaining to Track 2.[2672] This motion was granted by a February 14, 2023 ALJ Ruling.

As set forth in the January 6, 2023 Settlement, Cal Advocates and PG&E propose that PG&E's total cost recovery for the accounts set forth in therein be $183.353 million for the recorded expense costs (a reduction of $25.600 million to PG&E's total request of $208.953 million) and $126.666 million of recorded capital costs (a reduction of $2.300 million to PG&E's total request of $128.966 million).[2673] The Settlement does not include a calculation of the resulting impact on PG&E's requested revenue requirement or an explanation of how the provisions of the Settlement impact PG&E's initial calculation of $241 million.

On February 6, 2023, the Peninsula Corridor Joint Powers Board (Caltrain) filed response to this motion for adoption of a settlement. Caltrain supports the January 6, 2023 Settlement but raises issues addressed in detail by the Commission below.

[2672] January 6, 2023 Joint Motion of Pacific Gas and Electric Company and the Public Advocates Office at the California Public Utilities Commission for Admission of Testimony and Workpapers into Evidence

[2673] Joint Motion at 1.

For the reasons set forth in detail below, the Commission adopts the January 6, 2023 Settlement. No specific revenue requirement is provided in connection with the January 6, 2023 Settlement. In adopting the January 6, 2023 Settlement, the Commission finds that all issues set forth in Track 2 are resolved, consistent with the Scoping Memo, and PG&E is authorized to include in its revenue requirement the amounts for the individual balancing accounts and memorandum accounts set forth in the January 6, 2023 Settlement.

15.1. Ratemaking and the Role of Balancing and Memorandum Accounts

The basic underlying system of ratemaking in California is a forward test year of the expected cost and scope of a utility's operations, meaning the utility's rates are set prospectively in a GRC based upon a forecast of sales and operating costs, plus taxes, interest, and an expected return for the investors based on the investment in long-lived assets that serve the customers. Rates are set to give the company a reasonable opportunity to earn a fair return, but not a guarantee of a specific profit during the actual test year.

Within this framework, the Commission created balancing accounts to reduce the risks to ratepayers as well as investors where some costs are too uncertain to forecast with sufficient accuracy in a GRC. Refundable rates are set for the program based upon the best available forecast.[2674]

Memorandum accounts are typically created when circumstances are uncertain, e.g., for activities not yet found reasonable and necessary, and where such costs are likely uncertain, the Commission may provide a utility with authority to track those costs in a "memorandum account" and request authority

[2674] PG&E's tariff is available on its website at the following link: https://www.pge.com/tariffs/index.page.

from the Commission to recover the costs later after the utility demonstrates the reasonableness of its actions and the benefit of the activity to the ratepayers. Before the use of memorandum accounts, utilities were generally at risk of absorbing activities unforeseen in between GRCs and only be able to recover forecast costs in its next test year. PG&E currently has numerous memorandum accounts.

Over time, more of the costs incurred by PG&E have been included in either balancing or memorandum accounts, reducing the share of the companies' costs subject to forecast risk in the test year forecasts for a GRC. In this proceeding, PG&E is requesting authorization from the Commission to recover in its revenue requirement the outstanding balances in the balancing and memorandum accounts included in the January 6, 2023 Settlement.

15.2. January 6, 2023 Settlement

As already noted, Cal Advocates is the only party to submit testimony on these issues in Track 2 and the only party to the settlement with PG&E on the issues in Track 2. PG&E and Cal Advocates agree that PG&E's total cost recovery for the Track 2 accounts shall be $183.353 million of recorded expense costs (a reduction of $25.600 million to PG&E's total request of $208.953 million) and $126.666 million of recorded capital costs (a reduction of $2.300 million to PG&E's total request of $128.966 million).[2675] In addition, PG&E and Cal Advocates agree on the following ratemaking matters

(1) The revenue requirement for recovery of the amounts agreed to in the Settlement shall be calculated consistent with the methodology described in PG&E's Prepared Testimony (PG&E Ex-80, Ch. 7) and that the gas revenue requirement associated with the amounts in Tables 3 and

[2675] *Joint Motion*, Attachment A, Settlement at 4.

4 will be recovered over two years as described in PG&E's Prepared Testimony (Exhibit PG&E-80, Ch. 7 at 7-13);

(2) The $272.2 million in costs PG&E incurred for projects completed in the Mobile Home Park (MHP) Pilot Program from January 1, 2018, through December 31, 2020, were reasonably incurred; and,

(3) The Greenhouse Gas Expense Memorandum Account GHGEMA shall be closed effective January 1, 2023.[2676]

15.3. Standard of Review for Settlements

The Commission has long favored the settlement of disputes. This policy supports many worthwhile goals, including reducing litigation costs, conserving scarce resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.[2677] Although the Commission favors settlements, it has specific rules regarding the submission, review, and approval of them. In evaluating whether to approve this Settlement, the Commission is guided not only by its precedents on settlements, but also by the overall "just and reasonable" standard of the Public Utilities Code.[2678]

Rule 12.1 of the Commission's Rules of Practice and Procedure sets forth the Commission's standard of review for evaluation of settlements. The Commission may only adopt a settlement after determining whether the settlement complies with Rule 12.1.(d):

> The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest. The Commission may reject any proposed

[2676] *Joint Motion*, Attachment A, Settlement at 22-23.

[2677] D.05-03-022 at 7-8.

[2678] Pub. Util. Code § 451, which requires that public utility rates "shall be just and reasonable."

settlement for failure to disclose the information required pursuant to subsection (a) of this rule.

PG&E bears the burden of proof to show that its requests are just and reasonable and any related ratemaking mechanisms are fair. To approve the settlement, the Commission must find that the parties had a sound and thorough understanding of PG&E's application, and of all the underlying assumptions and data included in the record. This level of understanding of the application and the record is necessary to meet our requirements for considering any settlement.

The record in this proceeding consists of all filed documents, the testimony received into evidence related to the subject of the proposed settlement and the Joint Motion by PG&E and Cal Advocates requesting the Commission's adoption of the Settlement. A list of the admitted exhibits is attached to the Joint Motion.

Rule 12.1(d) provides that settlements need not be joined by all parties, and the January 6, 2023 Settlement is not an all-party settlement. However, the January 6, 2023 Settlement is not contested. As discussed below, the Commission finds that the January 6, 2023 Settlement meets the criteria set forth in Rule 12.1(d) of the Commission's Rules of Practice and Procedure.

The components of the January 6, 2023 Settlement are summarized below together with the agreed upon resolution of each component. A description of each settled balancing account or memorandum account is provided, with information pertaining to PG&E's request in its June 30, 2021 Application, as compared to Cal Advocates' litigation recommendations and to the settled amount noted as well. Because settlements discussions are confidential, the Commission does not speculate or dissect why the parties agreed upon any particular settlement position or why they agreed to any specific adjustments, as shown below. In evaluating this Settlement, the Commission accepts that

Cal Advocates has the expertise and reasoned judgement to decide to settle a matter rather than litigate.

15.4. Gas Expenses

15.4.1. Gas Statutes Regulations and Rules Memorandum Account (GSRRMA)

The purpose of the Gas Statutes Regulations and Rules Memorandum Account (GSRRMA) is as follows:

> [T]o track and record incremental costs to comply with any new federal or state statutes, regulations and rules, or new or changed interpretation by a regulatory body of statutes, regulations and rules, that are issued between GT&S funding cycles for which PG&E has not been able to incorporate a forecast of costs into a rate case and which are not already addressed and recorded in another account."[2679]

PG&E's Request	$ 27,833,000[2680]
Cal Advocates' Proposed Reduction	$ 27,800,000
Settlement Reduction	$ 9,000,000
Final GSRRMA Recoverable Amount	$ 18,833,000[2681]

For the reasons set forth below in more detail, the Commission finds this Settlement amount for the Gas Statutes Regulations and Rules Memorandum Account (GSRRMA) of $18,833,000 reasonable.

15.4.2. Critical Documents Program Memorandum Account

The purpose of the Critical Documents Program Memorandum Account (CDPMA) is as follows:

[2679] PG&E's Gas Tariff Preliminary Statement. All account descriptions herein are found in IPG&E's Tariff on PG&E's website at the following link: GAS_PRELIM_EL.pdf (pge.com) (current tariff as of February 10, 2023).

[2680] January 6, 2023 Settlement, Attachment 2, Tables 1-4, citing to PG&E's December 23, 2022 errata testimony.

[2681] January 6, 2023 Settlement at 4 ff.

> [R]ecord and track actual expenses related to updating existing station documents or creating new documentation to meet the standard set in Utility Standard TD-4551S for all Measurement & Control facilities and Compression and Processing facilities built on or before December 31, 1955.
>
> This account is comprised of a main account, which records backbone transmission and/or storage costs for future recovery from all customers and a Local Transmission Subaccount, which records local transmission costs for future recovery from all customers except Backbone Service-Level end-use customers who do not fund local transmission activities.[2682]

PG&E's Request	$ 15,051,000
Cal Advocates' Proposed Reduction	$ 15,051,000
Settlement Reduction	$ 5,900,000
Final CDPMA Recoverable Amount	$ 9,151,000

For the reasons set forth below in more detail, the Commission finds this Settlement amount for the CDPMA of $9,151,000 is reasonable. In addition, PG&E's uncontested proposal to close the CDPMA is approved and the Commission directs PG&E to close this account by filing a Tier 2 Advice Letter.

15.4.3. Internal Corrosion Direct Assessment Memorandum Account

The purpose of the Internal Corrosion Direct Assessment Memorandum Account (ICDAMA) is as follows:

> [T]o track actual expenses incurred for the Internal Corrosion Direct Assessment Program during the 2019 Gas Transmission and Storage (GT&S) rate case cycle (2019-2022). The account is subject to a reasonableness review in PG&E's next GT&S Rate Case.
>
> This account is comprised of a main account, which records backbone transmission and/or storage costs for future recovery from all customers and a Local Transmission (LT)

[2682] PG&E's Gas Tariff Preliminary Statement.

> Subaccount, which records local transmission costs for future recovery from all customers except Backbone Service-Level end-use customers who do not fund local transmission activities.[2683]

PG&E's Request	$ 14,320,000
Cal Advocates' Proposed Reduction	$ 11,600,000
Settlement Reduction	$ 5,000,000
Final ICDAMA Recoverable Amount	$ 9,320,000

For the reasons set forth below in more detail, the Commission finds this Settlement amount of $9,320,000 for the ICDAMA is reasonable.

PG&E requests that the Commission close the ICDAMA and record the ICDA in the Transmission Integrity Management Program Memorandum Account (TIMPBA). Cal Advocates contests this request. The Commission addresses PG&E's contested request at Section 3.4.7, where the Commission finds it reasonable for this account to remain open. With respect the opposed request by PG&E to close the memorandum accounts, the Commission denies PG&E's requests and directs PG&E to propose these changes at a later date.

15.4.4. In-Line-Inspection Memorandum Account

The In-Line-Inspection Memorandum Account (ILIMA) is as follows:

> [T]o track the revenue requirement associated with the actual capital expenditures for Traditional In-Line Inspection (ILI) upgrade projects above the total authorized 48 projects (12-project per year pace), and actual expenses incurred for the associated initial Traditional ILI runs and Direct Examination and Repair (DE&R) resulting from the initial runs. In addition, the ILIMA will track expenses associated with all reassessments. The account is subject to a reasonableness review in PG&E's next Gas Transmission and Storage (GT&S) Rate Case.

[2683] PG&E's Gas Tariff Preliminary Statement.

> This account is comprised of a main account, which records backbone transmission and/or storage costs for future recovery from all customers and a Local Transmission Subaccount, which records local transmission costs for future recovery from all customers except Backbone Service-Level end-use customers who do not fund local transmission activities.[2684]

PG&E's Request	$ 148,416,000
Cal Advocates' Proposed Reduction	$ 5,700,000
Settlement Reduction	$ 5,700,000
Final ILIMA Recoverable Amount	$ 142,716,000

For the reasons set forth below in more detail, the Commission finds this Settlement amount of $142,716,000 for the ILIMA is reasonable.

PG&E request the Commission authorize PG&E to close the ILIMA. TURN supports PG&E's request while Cal Advocates opposes the request. The Commission addresses PG&E's request at Section 3.4.7, herein, where it finds it reasonable to close this account because the number of ILI upgrades is determined in this GRC to be four.

15.4.5. Dairy Biomethane Solicitation Memorandum Account

The purpose of the Dairy Biomethane Solicitation Memorandum Account (DBSMA) is as follows:

> [R]ecord expenditures for solicitation development in accordance with CPUC approved D.17-12-004.[2685]

PG&E's Request	$ 67,000
Cal Advocates' Proposed Reduction	$ 67,000
Settlement Reduction	$ 0
Final DBSMA Recoverable Amount	$ 67,000

[2684] PG&E's Gas Tariff Preliminary Statement.

[2685] PG&E's Gas Tariff Preliminary Statement.

For the reasons set forth below in more detail, the Commission finds this Settlement amount of $67,000 for the DBSMA is reasonable.

15.4.6. Transmission Integrity Management Program Memorandum Account

The Purpose of the Transmission Integrity Management Program Memorandum Account (TIMPMA) is as follows:

> [T]rack Transmission Integrity Management Program (TIMP) expenses incurred during the 2019 Gas Transmission and Storage (GT&S) rate case cycle (2019 through 2022), up to the total amounts adopted in D.19-09-025 (Appendix G, Table 1) or CPUC Decision further modifying adopted amounts. The TIMPMA is a one-way balancing account.
>
> This account is comprised of a Main Account, which tracks amounts related to backbone transmission and/or storage activity that is recovered from all customers and a Local Transmission Subaccount, which tracks amounts related to local transmission activity that is recovered from all customers except Backbone Service-Level end-use customers who do not fund local transmission activities.[2686]

This account balance was uncontested and the Final TIMPMA Recoverable Amount is $315,000.

For the reasons set forth below in more detail, the Commission finds this uncontested amount of $315,000 for the TIMPMA is reasonable. This account remains open.

15.4.7. Gas Storage Balancing Account (Expense Component)

The purpose of the Gas Storage Balancing Account (GSBA) for the expense component is as follows:

> [T]rack and record actual expenses and capital revenue requirements based on actual capital expenditures over the

[2686] PG&E's Gas Tariff Preliminary Statement.

> 2019 Gas Transmission and Storage (GT&S) rate case cycle (2019-2022), compared to the revenue requirements based on the adopted capital expenditures for PG&E's natural gas storage facilities, excluding Gill Ranch. The GSBA is a two-way balancing account. The account is subject to a reasonableness review in PG&E's next GT&S Rate Case.[2687]

This account balance was uncontested and the Final GSBA's Expense Component's Recoverable Amount is ($6,456,000), i.e., a refund to ratepayers.

For the reasons set forth below in more detail, the Commission finds this uncontested amount of $6,456,000 for the GSBA is reasonable. This account remains open.

15.5. Electric Expenses

15.5.1. Distribution Resources Plan Tools Memorandum Account (Expense Component)

The purpose of the expense component of the DRPTMA is as follows:

> [R]ecord and track incremental costs, both capital and expense, incurred to implement demonstration project tools on Integration Capacity Analysis (ICA) and Locational Net Benefit Analysis (LNBA) associated with the Distribution Resources Plan to be implemented pursuant to Decision (D.) 17-09-026. Pursuant to D.18-02-004, DRPTMA will also include a subaccount to track debits and credits, both capital and expense, associated with implementing the annual Distribution Investment Deferral Framework (DIDF) which includes Grid Needs Assessment (GNA), Distribution Deferral Opportunity Report (DDOR), and the Data Access Portal mandated by D.18-02-004.[2688]

[2687] PG&E's Gas Tariff Preliminary Statement.

[2688] PG&E's Electric Tariff Preliminary Statement.

PG&E's Request	$	9,022,000
Cal Advocates' Proposed Reduction	$	484,000
Settlement Reduction	$	0
Final DRPTMA Recoverable Amount	$	9,022,000

For the reasons set forth below in more detail, the Commission finds this Settlement amount of $9,022,000 for the expense component in the DRPTMA is reasonable. This account remains open.

15.5.2. Avoided Cost Calculator Update Memorandum Account

The purpose of the Avoided Cost Calculator Update Memorandum Account (ACCUMA) is as follows:

> [T]rack and record PG&E's portion of costs reimbursed to the Commission or their contractor for updating the Avoided Cost Calculator and providing technical assistance or research for the purpose of advancing future refinement of cost-effective methods. Amounts paid by PG&E may not exceed PG&E's portion of the adopted funding of $500,000 per year for three years beginning with fiscal year 2016-17, and $100,000 per year thereafter beginning in fiscal year 2019-20 on a going forward basis until or unless the Commission determines that updates to the Avoided Cost Calculator are no longer needed. The funds reimbursed by the utilities will be based on their current energy efficiency allocation, as determined in R.13-11-005.[2689]

This account balance was uncontested and the final ACCUMA Recoverable Amount is $385,000.

For the reasons set forth below in more detail, the Commission finds this uncontested amount of $385,000 for the ACCUMA is reasonable. This account remains open.

[2689] PG&E's Electric Tariff Preliminary Statement.

15.6. Gas Capital Revenue Requirement

15.6.1. Line 407 Memorandum Account

The purpose of the Line 407 Memorandum Account (L407MA) is as follows:

> [R]ecord the revenue requirement associated with the actual capital expenditures incurred for the construction of the Line 407 project, above $180.8 million as authorized by the Commission in D.19-09-025, PG&E's 2019 Gas Transmission and Storage (GT&S) rate case. The costs above $180.8 million are subject to a reasonableness review in PG&E's next Gas Transmission and Storage (GT&S) Rate Case. L407 is a local transmission asset and therefore only local transmission costs are recorded to this account.[2690]

PG&E's Request	$	8,977,000
Cal Advocates' Proposed Reduction	$	3,700,000
Settlement Reduction	$	0
Final L407MA Recoverable Amount	$	8,977,000

For the reasons set forth below in more detail, the Commission finds this Settlement amount of $8,977,000 for L407MA is reasonable. This account remains open.

15.6.2. Measurement & Control Station Over- Pressure Protection Memorandum Account

The purpose of the Measurement & Control Station Over-Pressure Protection Memorandum Account (MCOPPMA) is as follows:

> [T]rack the revenue requirement associated with capital expenditures for the Measurement and Control Station Over-Pressure Protection Program during the 2019 Gas Transmission and Storage (GT&S) rate case cycle. The account is subject to a reasonableness review in PG&E's next GT&S Rate Case.

[2690] PG&E's Gas Tariff Preliminary Statement.

> This account is comprised of a main account, which records backbone transmission and/or storage costs for future recovery from all customers and a Local Transmission Subaccount, which records local transmission costs for future recovery from all customers except Backbone Service-Level end-use customers who do not fund local transmission activities.[2691]

This account balance was uncontested and the final MCOPPMA Recoverable Amount is $44,297,000.

For the reasons set forth below in more detail, the Commission finds this uncontested amount of $44,297,000 for MCOPPMA is reasonable.

In addition, the Commission addresses PG&E's uncontested proposal to close the MCOPPMA, the Commission directs PG&E to file a Tier 2 Advice Letter to close this account.

15.6.3. Gas Storage Balancing Account (Capital Component)

The purpose of the Gas Storage Balancing Account (GSBA) for the capital component is described above in the GSBA Expense Component.

This account balance was uncontested and the final GSBA Capital Component's Recoverable Amount is $59,129,000. PG&E's states that the revenue requirement associated with this amount is $10.706 million.[2692]

For the reasons set forth below in more detail, the Commission finds this uncontested amount of $59,129,000 for the GSBA capital component is reasonable. This account remains open.

[2691] PG&E's Gas Tariff Preliminary Statement.

[2692] PG&E Ex-83 at 12.

15.7. Electric Capital Revenue Requirement

15.7.1. Caltrain Substation Upgrade Cost Recovery

PG&E's Application requested recovery of $10,479,000 of capital expenditures, which represents 60% of the audited CPUC-jurisdictional capital costs for upgrading the PG&E East Grand and FMC substations to enable the electrification of Caltrain's commuter rail service between San Jose and San Francisco.[2693] PG&E's Application also requested that the Commission reaffirm the 60%(PG&E) - 40%(Caltrain) cost allocation of the shared project costs as adopted in D.20-05-008.[2694]

D.20-05-008 ordered PG&E's testimony in this GRC proceeding to explain why the substation upgrade costs PG&E incurred "are prudent and do not result in unjust and unreasonable rates. and "include the completed independent third-party audit of costs" associated with the PG&E substation upgrades.[2695] FERC accepted PG&E's filing with the proposed allocation of 60%-40%.[2696]

The Commission subsequently modified D.20-05-008 when it adopted D.22-08-003 in response to a petition to modify filed jointly by PG&E and Caltrain. In D.22-08-003, the Commission authorized PG&E to submit testimony

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[2693] PG&E requested that the Commission review these issues pertaining to Caltrain and the related costs in Track 2 of this proceeding at PG&E Ex-80 at 6-5 to 6-6 as a result of delays in auditing the cost, which is addressed in a May 26, 2022 Joint Petition for Modification of D.20-05-008 filed in A.18-12-017. The Commission granted this petition in D.22-08-003 (August 4, 2022).

[2694] PG&E Ex-4, Ch. 18 at 18-47, citing to D.20-05-008, Decision Adopting Settlement Agreement Between Peninsula Corridor Joint Powers Board and Pacific Gas and Electric Company (May 7, 2020).

[2695] D.20-05-008 at OP 6.

[2696] Caltrain's February 6, 2023 Comments at 3 in fn. 6, *citing to* November 10, 2021, FERC Letter Order (FERC Docket No. ER21-2901-000), which is the final and non-appealable decision that approved revisions to Supplement Nos. 3 and 4 of the PG&E/Caltrain Settlement Agreement that reflect that agreed upon 60%/40% cost allocation.

in Track 2 to seek recovery of the PG&E substation upgrade costs based on an audit of the incurred and settled costs as of May 31, 2022 (estimated to be 95% of the total PG&E's costs).[2697]

On September 30, 2022, PG&E complied with these requirements. The audit covered the project costs invoiced through May 31, 2022, representing $111.5 million, approximately 92.7% of the total costs PG&E then-projected to complete the PG&E upgrades. The CPUC-jurisdictional amount is approximately $17,465,050 (15.7%).[2698] While anticipating incurring an additional $8.7 million in capital expenditures before the Caltrain Project is complete,[2699] "PG&E states that it expects that all these post-May 31, 2022 costs will be FERC-jurisdictional. However, in accordance with D.22-08-003, these costs will be audited after project completion and PG&E will report on them (and seek recovery of additional CPUC-jurisdictional costs, if any) through a Tier 2 Advice Letter, which will include the final audit as support."[2700]

Cal Advocates recommended disallowing the entire amount for the PG&E upgrades becausePG&E: (1) did not provide documentation required to verify, evaluate, and independently calculate its cost recovery; (2) did not demonstrate that costs are appropriate for inclusion in CPUC-jurisdictional rates, as opposed to FERC-jurisdictional rates; (3) failed to provide documentation explaining specific work performed on the Caltrain Project; and (4) failed to provide adequate support and calculation to demonstrate the increase in its original

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[2697] Caltrain's February 6, 2023 Comments at 3, *citing to* D.22-08-003, OP 1, Modification to OP 6(a) of D.22-05-008.

[2698] PG&E Ex-82 at 6S-3.

[2699] PG&E Ex-82 at 6S-3.

[2700] PG&E Ex-82 at 6S-4.

Track 1 request of approximately $6 million to its Track 2 request of nearly $10.5 million.[2701]

After settlement discussions, Cal Advocates and PG&E agreed to a reduction of capital expenditures of $2,300,000, as reflected in the January 6, 2023 Settlement, for total capital of $8,176,000 for capital expenditure costs for the Caltrain Project; that the Commission should reaffirm the 60%-40% cost allocation approved by the Commission in D.20-05-008; and that the $2,300,000 reduction related to the Caltrain Upgrades would be a "permanent" disallowance from PG&E's CPUC-jurisdictional rate base. In effect, PG&E is not permitted under the January 6, 2023 Settlement to seek recovery before this Commission of $2,300,000. The Settlement does not preclude PG&E from seeking recovery of this $2,300,000 in FERC-jurisdictional transmission rates.[2702]

Caltrain supports adoption of the January 6, 2023 Settlement but also requests prompt resolution of this matter.[2703] Caltrain recommended that the Commission consider this matter as soon as possible in a separate decision, independent from a final and potentially later GRC decision, to expedite PG&E's providing payment to Caltrain of 60% of costs, which Caltrain has financed for the upgrade. Caltrain's noted that under the September 23, 2019 Settlement adopted by the Commission in D.20-05-008, Caltrain agreed to advance 100% of the capital costs and the other cost to finance PG&E's construction of the substation upgrades and that PG&E is required to reimburse Caltrain for 60% of

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[2701] CALPA Ex-04 at 4, 5, 8, and 10.

[2702] *Joint Motion* at 4 and Attachment A at 7.

[2703] February 6, 2023 Comments of Peninsula Corridor Joint Powers Board on the Joint Motion of Pacific Gas and Electric Company and the Public Advocates Office Requesting Approval of A Settlement of Track 2 Issues.

these capital and other costs upon receipt of certain other regulatory approvals, including a decision by the Commission in this proceeding.[2704]

On February 21, 2023, PG&E filed a reply to Caltrain's and recommended that the Commission expedite resolution of the entire GRC and not give special treatment to this issue.[2705] No other party filed responsive pleadings to the January 6, 2023 Settlement. As such, the Settlement is unopposed.

Regarding the January 6, 2023 Settlement, the Commission finds the costs presented for PG&E's Substation Upgrades related to Caltrain reasonable. Furthermore, as directed by D.20-05-008, the Commission reaffirms the 60% (PG&E)-40% (Caltrain) cost allocation approved by the Commission in D.20-05-008. Accordingly, the Commission adopts total capital expenditures of $8,176,000 for the Caltrain Project and PG&E is authorized to include these costs in rate base and revenue requirement beginning in 2023.

Regarding the provision of the January 6, 2023 Settlement that leaves open the possibility that PG&E could seek recovery in FERC-jurisdictional rates of costs for the Caltrain Station Upgrades, including the $2,300,000 reduction set forth in the January 6, 2023 Settlement, the Commission has a long-standing practice of intervening as an interested party in FERC proceedings which impact California energy consumers. The January 6, 2023 Settlement in no way limits the

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[2704] February 6, 2023 Comments of Peninsula Corridor Joint Powers Board on the Joint Motion of Pacific Gas and Electric Company and the Public Advocates Office Requesting Approval of A Settlement of Track 2 Issues at 2. PG&E Ex-80 at 6-2 to 6-3. PG&E explains that Resolution E-4886 issued on September 27, 2018 ordered PG&E to file an application to seek approval of cost allocation between it and Caltrain for a proposal referred to as Supplement No. 3 and any further supplements to the Master Agreement for interconnection work on the Caltrain Project. (PG&E Ex-80 at 6-3 to 6-17). This Application was A.18-12-017 and resulted in D.20-05-008.

[2705] February 21, 2023 Pacific Gas and Electric Company's (U 39 E) Reply Comments Regarding Motion to Approve Track 2 Settlement at 2.

Commission's authority to participate in any subsequent FERC proceeding where PG&E may seek to recover the costs for the Caltrain Station Upgrades, including the $2,300,000 capital costs reduction.

15.7.2. Distribution Resources Plan Tools Memorandum Account (Capital Component)

The purpose of the Distribution Resources Plan Tools Memorandum Account (DRPTMA) for the capital component is described above in the discussion regarding the DRPTMA expense component.

PG&E's Request	$ 6,087,000
Cal Advocates' Proposed Reduction	$ 1,100,000
Settlement Reduction	$ 0
Final DRPTMA Recoverable Amount	$ 6,087,000

For the reasons set forth below in more detail, the Commission finds this Settlement amount of $6,087,000 DRPTMA for the capital component is reasonable.

15.7.3. Mobile Home Park Balancing Account

PG&E's July 22, 2022 request regarding Track 2 recommended that the Commission conduct a reasonableness review of $272,200,000 associated with the Mobile Home Park Pilot Program, a pilot undertaken by PG&E between January 1, 2018 and December 31, 2020. PG&E recorded these costs of $272,200,000 in its Mobile Home Park Balancing Account (MHPBA) and does not request recovery of these costs in this proceeding.[2706] PG&E explains that it is not seeking cost recovery for the Mobile Home Park Pilot Program in this GRC proceeding as the costs incurred for these projects have been recovered through the electric and gas Mobile Home Park Balancing Account.[2707]

[2706] Joint Motion at 4.

[2707] *Joint Motion* at 13; PG&E Ex-12 at 7-21 to 7-24 (Table 7-4).

The January 6, 2023 Settlement agrees that the $272.2 million in costs that PG&E incurred for projects and activities associated with its Mobile Home Park Pilot Program from January 1, 2018, through December 31, 2020 were reasonably incurred. No parties objected to this agreed amount.

As explained below, the Commission finds these costs of $272.2 million as agreed upon by PG&E and Cal Advocates reasonable as a component of the January 6, 2023 Settlement. These amounts are not included in the revenue requirement adopted by this decision as PG&E recovers these costs separately.

15.7.4. Greenhouse Gas Expense Memorandum Account

As a part of the January 6, 2023 Settlement, PG&E and Cal Advocates agree to close the Greenhouse Gas Expense Memorandum Account (GHGEMA). PG&E did not include the GHGEMA in the list of accounts to be discontinued in this proceeding.[2708] PG&E added this account to its request in Track 2 in compliance with D.15-10-032.[2709] PG&E's and Cal Advocate's proposal is uncontested. Accordingly, the Commission adopts this aspect of the Settlement and directs PG&E to file a Tier 2 Advice Letter to close the GHGEMA, effective January 1, 2023.

15.8. Revenue Requirement

PG&E and Cal Advocates agree in the January 6, 2023 Settlement to certain ratemaking principles pertaining to the revenue requirement for the amounts set

[2708] PG&E June 30, 2021 Application; PG&E Ex-12, Table 7-4.

[2709] D.15-10-032, Decision Adopting Procedures Necessary for Natural Gas Corporations to Comply with the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (Cap-And-Trade Program (October 22, 2015) at 60 (Conclusion of Law 18) stating "The memorandum accounts adopted in this proceeding should sunset for each utility once that utility has had the opportunity to request approval of natural gas GHG-related administrative costs in its next general rate case or similar proceeding."

forth in the Settlement (contested and uncontested). The Commission has reviewed this aspect of the Settlement and agrees that the revenue requirement for recovery of the amounts agreed to in the Settlement shall be calculated consistent with the methodology described in PG&E's testimony with the gas and electric revenue requirement associated with the amounts in the Settlement to be recovered over two years as described in PG&E's testimony.[2710]

15.9. Discussion

The Commission has reviewed the January 6, 2023 Settlement and the supporting documents in the record. The Commission concludes that Settlement resolves the disputed issues in a balanced way which reflects a compromise of the positions presented in the record of the proceeding, as litigated by PG&E and Cal Advocates. As such, the Commission finds the January 6, 2023 Settlement reasonable in light of the whole record.

This Settlement only resolves disputed issues pertaining to Track 2 of the proceeding and other disputed issues are addressed elsewhere in this decision. The Commission notes that Cal Advocates, one of the settling parties, is statutorily charged to represent a broad spectrum of ratepayer interests. As such, the Commission finds the Settlement to be in the public interest.

Furthermore, the Commission finds further find that no terms within the settlement can bind the Commission in the future or violate existing law. Accordingly, the Commission finds the Settlement is consistent with the law.

As noted above, PG&E removed certain balancing accounts and memorandum accounts pertaining to wildfire mitigation activities from its proceeding and filed a separate application, A.22-12-009, seeking authorization

[2710] PG&E Ex-80, Ch. 7.

to include those amounts into its revenue requirement. No determination is made here regarding those removed accounts. The Commission also finds that PG&E and Cal Advocates addressed and resolved all issues identified in the Scoping Memo related to PG&E's balancing accounts and memorandum accounts in this Settlement, consistent with the modification to the accounts in Track 2 by PG&E on July 22, 2022.

In addition, the Commission exercises its discretion not to change the Settlement unilaterally based upon our own review of the original positions of PG&E and Cal Advocates as embodied in their testimony and exhibits identified and received into the record of this proceeding.

Therefore, upon review of the uncontested January 6, 2023 Settlement between PG&E and Cal Advocates, as summarized above, the Commission finds the January 6, 2023 Settlement reasonable in light of the whole record, consistent with the law, and in the public interest. The Commission further finds that the record in this proceeding and information presented in the Settlement establish that Cal Advocates and PG&E have the necessary understanding of the issues and facts, and the capacity to engage in the settlement process.

Accordingly, the Commission adopts the January 6, 2023 Settlement resolving the issues presented in remaining matters presented in Track 2 of this proceeding.

16. Final Authorized Revenue Requirement and Amounts Recorded in Memorandum Accounts

This Section addresses costs recorded in memorandum accounts that the Commission has not yet reviewed for reasonableness and concludes that such costs should be removed from PG&E's revenue requirement authorized in this proceeding. PG&E may file an application for reasonableness review of these amounts, to the extent it has not already done so, and recover those amounts as directed by the Commission in those proceedings.

In order to obtain cost recovery of amounts recorded in memorandum accounts, a utility must establish that it has incurred the cost, that the assets at issue are used and useful in the case of capital expenses, and, in addition, that the costs are just and reasonable. Because the Commission has not yet reviewed costs in certain PG&E memorandum accounts for justness and reasonableness, it is premature for PG&E to include these costs in its requested revenue requirement or in the amounts that form the basis for the calculation of that revenue requirement within the Result of Operations modeling.

On August 3, 2023, TURN filed a motion alleging that PG&E included in its requested revenue requirement – and related Results of Operations modelling – amounts it had recorded in memorandum accounts that the Commission has not yet reviewed for reasonableness.[2711] According to TURN, when PG&E filed this application on June 30, 2021, it included a request for the Commission to review and authorize recovery of certain costs related to wildfire mitigation and recorded in memorandum accounts.[2712] On February 25, 2022, PG&E removed its request for the Commission to review these wildfire-related amounts in this proceeding, opting under Pub. Util. Code Section 8386.4 to file a separate application seeking recovery.[2713] PG&E filed A.23-06-008 to seek

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[2711] August 3, 2023 Motion Of the Utility Reform Network To Set Aside Submission to Take Additional Evidence Regarding Capital Revenue Requirements Prematurely Included In Pacific Gas and Electric Company's Request (August 3, 2023 TURN motion) at 1.

[2712] August 3, 2023 TURN Motion at 7.

[2713] Pub. Util. Code Section 8386.4(b) provides:

(b) (1) The commission shall consider whether the cost of implementing each electrical corporation's plan is just and reasonable in its general rate case application. Each electrical

Footnote continued on next page.

reasonableness review of these wildfire mitigation plan costs in memorandum accounts. TURN is a party to A.23-06-008.

TURN's August 3, 2023 motion explains that during discovery in A.23-06-008, PG&E revealed that the costs in memorandum accounts at issue are included in PG&E's revenue requirement for which it seeks recovery in this GRC.[2714] Asserting that such inclusion is premature, TURN's motion requested that the ALJ set aside submission of this proceeding to take additional evidence on the matter.[2715] On August 4, 2023, the ALJs issued a ruling directing parties to file responses to TURN's motion on an expedited basis.

On August 8, 2023, PG&E filed a response in opposition to TURN's motion disputing some of TURN's facts and asserting that the Commission need not set aside submission of this proceeding to resolve the questions raised by TURN.[2716] Rather, PG&E suggested options for how to address the matters raised by TURN and timely resolve this proceeding. PG&E explained:

> If the Commission decides that certain revenue requirements should be removed, there are several ways this can be implemented consistent with final GRC ratesetting processes. The Commission can require PG&E to provide the necessary

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corporation shall establish a memorandum account to track costs incurred for fire risk mitigation that are not otherwise covered in the electrical corporation's revenue requirements. The commission shall review the costs in the memorandum accounts and disallow recovery of those costs the commission deems unreasonable.

(2) In lieu of paragraph (1), an electrical corporation may elect to file an application for recovery of the cost of implementing its plan as accounted in the memorandum account at the conclusion of the time period covered by the plan. If the electrical corporation files an application for cost recovery pursuant to this paragraph, the commission shall issue a proposed decision within 12 months of the filing date of the application unless the commission issues an order extending the deadline upon a finding of good cause.

[2714] August 3, 2023 TURN Motion at 5.

[2715] August 3, 2023 TURN Motion at 9.

[2716] August 8, 2023 PG&E Opposition To Motion Set Aside Submission at 9.

> cost and revenue requirement information to be incorporated into the Results of Operations Model calculations for the proposed and final decisions. Alternatively, the Commission can require PG&E to update the GRC revenue requirements in an advice letter as part of the GRC decision implementation. This post-decision practice is consistent with the typical practice following the Commission's GRC decision, in which the Commission requires the utility to submit various information and advice letters to implement the revenue requirement and ratemaking adopted in the decision.[2717]

On August 11, 2023, the ALJs issued a ruling directing PG&E to provide additional information on the memorandum accounts in TURN's August 3, 2023 motion and to identify other amounts recorded in memorandum accounts not yet reviewed for reasonableness but included in PG&E's requested revenue requirement here.[2718] On August 18, 2023, in response to the ALJs ruling, PG&E filed a response with information identifying the following memorandum accounts:[2719]

- Wildfire Mitigation Plan Memorandum Account (WMPMA)
- Fire Risk Mitigation Memorandum Account (FRMMA)
- Catastrophic Event Memorandum Account (CEMA)
- Measurement and Control Station Overpressure Protection Memorandum Account (MCOPPMA)
- L407MA - Line 407 Memorandum Account (L407MA)

[2717] August 8, 2023 PG&E Opposition To Motion Set Aside Submission at 9.

[2718] August 11, 2023 Email Ruling Issued by Administrative Law Judges.

[2719] August 18, 2023 PG&E Response in Compliance With Administrative Law Judges' August 11, 2023 Ruling at Attachment 1 Table PACIFIC GAS AND ELECTRIC COMPANY GRC-2023-PhI_DR_CPUC_001-Q001-003 2023-2026 CAPITAL REVENUE REQUIREMENT ESTIMATION. (Further detail about the memorandum accounts were attached to PG&E's response and are found at Appendix C, hereto.)

- DRPTMA - Distribution Resource Plan Tools Memorandum Account (DRPTMA)
- Dairy Biomethane Pilots Memorandum Account (DBPMA)

In this response, PG&E also provided an estimate of the impact on its revenue requirement from the inclusion of the amounts recorded in these memorandum accounts before Commission reasonableness review, as follows:[2720]

2023-2026 Capital Revenue Requirement Estimates provided by PG&E on August 18, 2023 ($ in thousands)

Memo Acct.	Function	2023	2024	2025	2026	Total
WMPMA and FRMMA	Electric Distribution	147,730	141,454	139,032	134,329	562,545
WMPMA and FRMMA	Common	34,708	33,391	32,558	31,068	131,724
CEMA	Electric Distribution	43,050	41,141	40,575	39,192	163,957
CEMA	Gas Distribution	11,308	10,812	10,630	10,295	43,044
MCOPPMA	Gas Transmission & Storage	8,503	8,186	8,059	7,839	32,588
L407MA	Gas Transmission & Storage	1,039	997	984	970	3,989
DRPTMA	Common	2,658	2,482	2,366	1,563	9,069
DBPMA	Gas Transmission & Storage	962	936	911	887	3,696
Total		**249,958**	**239,398**	**235,115**	**226,141**	**950,612**

As indicated in the above chart, PG&E estimates that the total 2023-2026 revenue requirements associated with capital costs in these memorandum accounts presented in this proceeding is $950.612 million.[2721]

[2720] August 18, 2023 PG&E Response in Compliance with Administrative Law Judges' August 11, 2023 Ruling.

[2721] August 18, 2023 PG&E Response in Compliance With Administrative Law Judges' August 11, 2023 Ruling at Attachment 1.

Pursuant to Pub. Util. Code Section 8386.4, PG&E may seek review of costs in its wildfire mitigation memorandum accounts in its GRC or in a separate application, but not both. By including costs in its revenue requirement in this GRC that are also the subject of a separate reasonableness review application, PG&E is seeking recovery of these amounts in rates before it is appropriate to do so. PG&E asserts that it may receive cost recovery for any capital investment in assets that are used and useful regardless of whether the Commission has reviewed the costs for reasonableness. This is not correct.

For amounts recorded in memorandum accounts, the Commission must first review those costs for reasonableness, and to include costs in rate base they must be both used and useful as well as prudently incurred. This requirement derives from Pub. Util. Code Section 451, which provides that "All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge demanded or received for such product or commodity or service is unlawful." As the Commission stated in D.19-05-020, "We agree with TURN that SCE cannot establish reasonableness based simply on a claim that an expenditure was made and has resulted in an investment which is used and useful for SCE's customers."[2722]

Under the legal standard, PG&E's August 18, 2023 Response to ALJ Ruling indicates that PG&E includes capital in the revenue requirement subject to review in this proceeding that has not been authorized by the CPUC as required. According to PG&E's calculations as set forth in the above chart, PG&E's

[2722] D.19-05-020 at 333-340.

premature inclusion of this capital in its revenue requirement increases the PG&E's 2023 revenue requirement by $249.958 million.[2723] We are removing the revenue requirements for 2023 through 2026 associated with the amounts in the memorandum accounts, which PG&E's August 18, 2023 filing quantifies as $950.612 million. This number is subject to revision as final numbers become known, and the Commission directs PG&E to update this figure forthwith. The Commission finds it reasonable to implement the removal of these memorandum account amounts for 2023 by subtracting the associated $249.958 million revenue requirement estimate from the total 2023 revenue requirement.[2724] Similarly, the Commission finds it reasonable to reduce the attrition year revenue requirements by subtracting $239.398 million for 2024, $235.115 million for 2025, and $226.141 million for 2026.

PG&E will have the opportunity to seek recovery of such costs but must first request and obtain a determination from the Commission that the costs are just and reasonable. In fact, in several cases PG&E is seeking authorization to recover wildfire mitigation costs, e.g., PG&E Applications, A.21-09-008, A.22-12-009 and A.23-06-008. To the extent it has not already done so, PG&E may seek reasonableness review of each of these costs by application.

[2723] This total includes estimates for CEMA capital which we directed to be removed from the Results of Operations model in the Community Rebuild portion (Section 4.23) of this decision. In addition, this estimated total includes capital included in memorandum accounts that were addressed at Section 15, Track 2, here in.

[2724] The amount removed from the revenue requirement are subject to revision after PG&E completes the precise calculations in its Results of Operations model. CEMA amounts related to the Paradise rebuild have already been excluded in accordance with the discussion in Section 4.6 of this decision. Also, the memorandum account amounts found reasonable in the Track 2 discussion in Section 15, herein, have also already been incorporated into the Result of Operations model.

17. Comments on Alternate Proposed Decision

The alternate proposed decision of assigned Commissioner John Reynolds in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ________________, and reply comments were filed on ________________ by ________________. Pursuant to Rule 14.3(c), "[c]omments shall focus on factual, legal or technical errors in the proposed decision and in citing such errors shall make specific references to the record or applicable law. Comments which fail to do so will be accorded no weight." Pursuant to Rule 14.3(d), replies to comments "shall be limited to identifying misrepresentations of law, fact or condition of the record contained in the comments of other parties."

18. Assignment of Proceeding

John Reynolds is the assigned Commissioner, and Regina M. DeAngelis and John H. Larsen are the assigned Administrative Law Judges in this proceeding.

Findings of Fact

Section 1

1. There has been robust party participation throughout this proceeding.
2. Some PG&E customers are paying a substantial portion of their disposable income for electricity and gas. Coupled with PG&E's requesting revenue requirement increase of approximately 29.5%, affordability is a central issue in this proceeding. Affordability considerations require the Commission to scrutinize and allow only those investments and costs that are just and reasonable, and disallow those that provide minimal benefit from a safety and reliability perspective.

Section 2

3. PG&E filed its Risk Assessment Mitigation Phase (RAMP) Report on June 30, 2020 in A.20-06-012 in preparation for this GRC.

4. Risk Spending Efficiency factors are one factor used to determine whether utilities are effectively allocating resources to initiatives that provide the greatest risk reduction benefits per dollar spent in a manner consistent with past precedent.

5. The Deferred Work Settlement continues to provide benefits of transparent and agreed-upon standards against which PG&E's requests can be assessed and to ensure that ratepayers received value for funds already paid.

Section 3.3 Gas Mains and Services

6. The 2023 expense forecast for the Fitting Mitigation Program (MAT JQG) of $2.4 million is just and reasonable because is based on the same annual rate as the pilot replacement program of 480 fittings per year.

7. The 2023 expense forecast for the Cross Bore Program (MAT JQK) of $13.130 million is just and reasonable because it is based an inspection rate of 19,313 inspections per year that is consistent with a low-Risk Spending Efficiency and the unit cost is based on relevant historical data.

8. The 2023 capital forecast for the Steel Gas Pipeline Replacement Program (MAT 14A) of $99.200 million is just and reasonable because it is based on the relative risk of the 2020 replacement rate of 24.4 miles of pipeline per year and a cost-effective unit cost of $770 per foot.

9. The rate of 139 miles per year continues to be a reasonable rate of replacing plastic pipe (MAT 14D) for purposes of determining a forecast because it balances the associated risks of this pipe and its historical cost of replacement.

10. PG&E's lack of record-keeping is not consistent with its record-keeping requirements and does not warrant a forecast based on replacing more than 427 gas services per year through the Reliability Service Replacement Program (MAT 50B).

11. Funds PG&E has not been authorized to use to replace gas service lines through MAT 50B can be repurposed to incentivize the transition of home energy usage from gas to electric by adding such funds in the amount not authorized in MAT 50B to the Alternative Energy Program (MAT AB#)

Section 3.4 Gas Transmission Pipe

12. Performing in-line inspections at the rate of four segments of transmission gas pipeline per year is reasonable because it is not inconsistent with federal and state regulations and this rate is more cost-effective than a higher rate.

13. The 2023 capital forecast for traditional in-line inspections (ILI) upgrades (MAT 98C) of $54.132 million is reasonable because it is based on a rate of four upgrades per year and a unit cost for 2023 of $13.533 million per ILI upgrade project.

14. Performing 57 traditional in-line inspections (ILI) inspections during the 2023-2026 rate case period is reasonable because 28 segments are not ILI enabled and because 23 can be deferred until 2027.

15. The 2023 expense forecast for traditional in-line inspections (ILI) inspections (HPB) of $7.551 million and for non-traditional ILI inspections (HPR) of $3.360 million are reasonable because they are based 57 traditional ILI inspections, 48 non-traditional inspections and PG&E's unit cost.

16. The 2023 capital forecast for direct examination and repair (MAT 75P) of $12.868 million is reasonable because it is based on PG&E's historical data from 2016-2020, including 2020, that reflects a downward cost trend.

17. The unit cost of $113,258 per mile for direct examination and repair for in-line inspections is reasonable because it is based on PG&E's data for the same from 2016-2020, which includes an adequate number of projects.

18. The 2023 expense forecast for direct examination and repair (MAT HPI) of $45.003 million is reasonable because it is based on the unit cost of $113,258 for in-line inspections (ILI) per mile for 397.35 miles consistent with reduction of 51 ILI assessments for Expense MAT HPB and Expense HPR.

19. The unit cost of $113,258 for in-line inspections (ILI) per mile external corrosion direct assessment indirect inspections (MAT HPC) is reasonable because it is based on PG&E's historical recorded cost data from 2014-2019 and the application of an inflation factor for recorded costs from 2014 through 2016.

20. The 2023 expense forecast to complete external corrosion direct assessment indirect inspections (MAT HPC) of $6.895 million is reasonable because it is based on completing inspections on 268 miles of transmission pipelines in high consequence areas during the rate case period at a unit cost of $94,069 per survey mile.

21. The number of 168 digs per year of external corrosion direct assessment (ECDA) direct examinations (for MAT HPN) is reasonable because it is based on a project-by-project review of ECDA inspections that will occur during the rate case period and on applying a series of factors to each of these inspections to determine the estimated number of digs.

22. The 2023 expense forecast for external corrosion direct assessment (ECDA) direct examination (MAT HPN) of $34.393 million is reasonable because it is based on 168 ECDA direct examination digs per year.

23. The 2023 forecast for internal corrosion direct assessment (ICDA) engineering (MAT HPJ) of $0.671 million is reasonable because it is based on

TURN's unit cost that uses a longer period of historical recorded cost data (2014-2019) with more projects.

24. The 2023 expense forecast for internal corrosion direct assessment (MAT HPO) of $11.829 million is reasonable because it is based on the more accurate longer period of historical recorded cost data (2014-2019) consistent with ICDA Engineering (MAT HPJ).

25. The 2023 expense forecast for Stress Corrosion Cracking Direct Assessment (SCCDA) engineering and surveys of $1.63 million is reasonable because it is based on TURN's longer period of historical data and PG&E's underperformance of this work consistent with work for external and internal corrosion direct assessment work.

26. The 2023 expense forecast for Stress Corrosion Cracking Direct Assessment (SCCDA) digs of $15.910 million is reasonable as it is based on PG&E's unexplained underperformance of this work.

27. The 2023 expense forecast for the Transmission Integrity Management Program (TIMP) Direct Examination of $23.965 million is reasonable because it is based on meeting the accelerated compliance dates driven by the new Pipeline Hazardous Materials and Safety Administration (PHMSA) interpretation and optimizing the use of resources.

28. TURN's methodology for estimating the percentage of disallowance of the cost of pressure testing pipeline segments for which no documentation of pressure testing exists is reasonable because the disallowance applies to Transmission Integrity Management Program (TIMP) and non-TIMP testing and the relationship between disallowed cost and disallowed pipeline mileage is not linear.

29. TURN's cost model for Transmission Integrity Management Program (TIMP) and non-TIMP testing is reasonable because it is based on updated and corrected data.

30. PG&E can move 65 strength testing projects into the next rate case cycle because completing such projects during this rate cycle is not necessary and cost-effective.

31. The 2023 capital forecast for non-TIMP strength testing (MAT 75U) of $61.956 million in 2023 dollars is reasonably derived from adopted disallowance percentage, cost model, and removal of 65 projects.

32. The 2023 capital forecast for non-TIMP pipeline replacement in lieu of strength testing $36.080 million is reasonably based the adopted disallowance percentage cost model, and the removal of 65 projects.

33. The 2023 expense forecast for non-TIMP pipeline replacement in lieu of strength testing (MAT JT6) of $10.622 million is reasonably derived from TURN's adopted disallowance percentage and cost model, and the removal of removal of certain projects based on relevant compliance deadlines.

34. The 2023 expense forecast of $19.917 million for TIMP strength testing (MAT HPF) is unopposed, consistent with federal law, and reasonable.

35. The scope of the Vintage Pipeline Replacement Program (MWC 75E) continues to address potential threats not addressed by PG&E's other pipeline assessment and replacement programs.

36. The 2023 capital forecast for the Vintage Pipe Replacement Program (MWC 75E) of $3.7 million is reasonable because it addresses potential threats in a cost-effective manner.

37. The 2023 capital forecast for Shallow and Exposed Pipe Program (MATs 75K, 75M, 75T) of $20.485 million is reasonable as it is based on mitigating risk as

they arise in a cost-effective manner consistent with PG&E's historical spending for this program.

38. The 2023 expense forecast for the Public Awareness Program (MAT JT0) of $3.063 million is reasonable as it is based on PG&E's historical spending without including PG&E's full estimate for its proposed GPS program for which PG&E provided insufficient support.

39. PG&E's history of completing fewer In-line Inspection Upgrades than forecast continues to support retaining the In-line Inspection Balancing Account as a one-way balancing account.

40. The Commission's determination of the number of In-line inspection upgrades in this GRC obviates the need for the In-line inspection memorandum account.

41. The Transmission Integrity Management Program (TIMP) Balancing Account and Memorandum accounts continue to provide a reasonable method for ensuring the PG&E can continue to recover just and reasonable costs associated with unidentified potential regulation changes that impact the scope of Transmission Integrity Management work.

42. Maintaining a separate memorandum account to track internal corrosion direct assessment work is no longer necessary.

43. The Internal Corrosion Balancing Court continues to be necessary.

44. Continuation of the New Environmental Regulations Balancing Account continues to be reasonable due to the uncertainty regarding the number and cost of below ground Grade 3 leak repairs.

Section 3.5 Gas Facilities

45. The 2023 expense forecast for the gas transmission Routine Compression & Processing (MAT JTY) of $8.263 million is reasonably based on 2020 recorded

costs because during the last three years such of recorded data such costs consistently declined.

46. The 2023 capital forecast for the Brentwood Terminal Rebuild Project (MAT 765) of $8.711 million is reasonable and commensurate with the scope and timing of this work and the delays in completing it by PG&E.

47. A forecast of zero dollars for the gas transmission and Gas Distribution Measurement and Control Station Overpressure Protection Enhancements Program (MATs FHQ, JTX, 50N and 76G) is reasonable considering the low level of operational and risk reduction benefits compared to other work forecasted for this rate case period.

48. A forecast of zero capital funding for the High-Pressure Regulator (HPR) Program (MWC 2K) for this rate case period is reasonable because the HPR program is not supported with sufficient information regarding the age or useful life of assets PG&E proposes to replace or a cost-effective mitigation benefit.

49. Reprioritizing PG&E's 2023 capital forecast of $17.853 million for the High-Pressure Regulator Program for use in the Alternative Energy Program (AB#) is reasonable to facilitate transitioning customers from gas to electric service where consistent with the process of using Alternative Energy Program funds.

50. A 2023 forecast for the Tionesta Compressor Station Retirement Project (MAT 76X) of zero capital funding is reasonable because PG&E has not demonstrated that it complies with the criteria of the Deferred Work Settlement.

51. PG&E's capital forecast for the Los Medanos K-1 compressor replacement project (MAT 76X) of $50.980 million for the 2023-2026 period is reasonable because this project meets the criteria of the Deferred Work Settlement (DWS) and PG&E demonstrated the reasonableness of the alternative work.

Section 3.6 Gas Storage

52. PG&E's core peak gas demand forecast shown in the table for Updated Peak Day Supply Standard Analysis in Section 3.5.2 is reasonably based on an updated model, recent data (including the 2022 California Gas Report), the necessity of planning for extreme weather conditions, and other uncertainties.

53. PG&E's electric gas demand forecast shown in the table for Updated Peak Day Supply Standard Analysis in Section 3.6.2 is reasonably based on a variety of factors including an updated model, recent data (including the 2022 California Gas Report), the necessity of planning for extreme weather conditions, an increase in electric demand due to increased electric vehicle charging and home electrification, the correlation between core customer peak demand and electric generation peak demand, and the loss of storage withdrawal capacity due to increased well inspections required by CalGEM regulations.

54. The total gas demand presented in the table for the Updated Peak Day Supply Standard Analysis in Section 3.5.2 is reasonably based on the components of gas demand, supply and storage capacity.

55. PG&E's gas supply and demand forecasts and analysis indicates that it is not prudent to discontinue operation of PG&E's Los Medanos gas storage facility.

56. PG&E's capital forecast for additional well drilling tracked in MAT 3L1 of $18.886 million in 2023, $45.884 in 2024, and $32.973 in 2025 is reasonable considering that PG&E's gas supply and demand forecast analysis is uncertain, and without new wells, only shows a surplus in gas storage capacity of 68MMcfd for next winter.

57. PG&E's estimate for reworking two emergent wells per year (tracked in capital MAT 3L3) is reasonable considering the number of well pressure tests

that may be required by the California Geologic Energy Management Division and other factors.

58. TURN's unit cost for reworking wells of $3.031 million per well (in 2020 dollars) is reasonably based on an average weighted by the number of wells of each type.

59. PG&E's capital forecast for Controls and Monitoring (MAT 3L5) of $1.365 million in 2023, $7.525 million in 2024, and zero funding for years 2025 and 2026 is reasonably based on the retention of the Los Medanos gas storage facility.

60. An expense forecast for Well Reworks and Retrofits (MAT AH2) of $3.207 million in 2023, $3.283 million in 2024, $5.040 million in 2025, and $10.819 million in 2026 is reasonably based on PG&E's unit cost and number emergent inspections, except for 2026 which is reduced to six in 2026 due to the regulatory uncertainty regarding their necessity.

61. PG&E's Well Integrity Assessment Program (MAT AH1) expense forecast of $9.177 million in 2023, $9.640 million in 2024, $8.003 million in 2025, and $10.146 million in 2026 is reasonably based on ensuring gas storage well capacity by retaining Los Medanos and testing 12 new wells and 18 existing wells.

62. Modifying the Gas Storage Balancing Account to allow recorded costs to be reviewed annually by Tier 2 Advice Letter and either approved or converted to a Tier 3 Advice Letter or application reasonably review recorded costs in a more timely manner and provides parties an opportunity to request an alternative approach.

Section 3.7 Gas Operations and Maintenance

63. The 2023 expense forecast for the Locate and Mark Program (MAT DFA) of $74.277 million is reasonably based on PG&E's unit cost of $86 per Locate and Mark Ticket and 863,682 Locate and Mark tickets.

64. The 2023 forecast for gas distribution standby governance (MAT DFB) of $0.442 million is reasonable as it is consistent with the adopted growth rate for Locate and Mark tickets.

65. The 2023 forecast for Gas Transmission Standby Governance (MAT DFB) of $5.349 million is consistent with a projected growth rate for Locate and Mark tickets.

66. The 2023 expense forecast for the Meter Protection Program (MAT EXB) of $12.660 is reasonable as it is based on a projected total of 15,421 meter locations and a unit cost of $821 per location.

67. The 2023 capital forecast for the Meter Protection Program (MAT 27A) of $5.332 million is reasonable as it is based on a projected 184 meter units at the same cost per meter as PG&E's 2023 forecast.

Section 3.8 Gas Operation Corrosion Control

68. PG&E's 2023 expense forecast for Gas Main Atmospheric Corrosion Mitigation work (MAT FHL) of $3.184 million is reasonable as it is based on mitigating a projected 145 gas distribution main spans at a unit cost of $21,961 derived from average costs during the 2018-2020 period including costs associated with projects completed across PG&E's service territory.

69. PG&E's 2023 expense forecast for Gas Distribution Atmospheric Corrosion Mitigation Services (MAT FHM) of $12.272 million is reasonable as it includes: $1.6 million in 2023 to mitigate a projected 1,822 standard historic units (coating repair, coating replacement, and riser replacement) and an additional

$10.7 million to mitigate 55,000 new units associated with expanded remediation requirements for service risers at the soil-to-air interface.

Section 3.9 Gas Operations Leak Management

70. PG&E's 2023 expense forecast for Below Ground Distribution Main Leak Repair Program work (MAT FIG) of $33.715 million is reasonable based on PG&E's leak rate of 2.04% and unit cost of $8,871 calculated from 2020 data.

71. The 2023 expense forecast for Meter Set Leak Repair work (MAT FIS) of $9.278 is reasonable as it is based on a projected 80,000 meter repairs per year and PG&E unit cost of $115.98.

72. PG&E's 2023 capital forecast for the Below Ground Gas Distribution Service Replacement Program of $14.400 million is reasonable as it is based on projected 978 units is 2023.

73. The 2023 expense forecast for Transmission Pipe Leak Repair (MAT JOP) of $9.231 million which is based on TURN's five-year average from 2016-2020 for of $3,291.00 is reasonable.

Section 3.10 Gas System Operations

74. The 2023 expense forecast for Distribution Control Center Operations and Maintenance (MAT FGA) of $8.760 is reasonable because it includes a reduction of $0.078 million for a discontinued plan to consolidate training of Distribution and Transmission Control System employees.

75. The 2023 expense forecast for Gas Distribution Manual Field Operations (MAT FGB) of $0.957 million is reasonable as it is based on maintaining the 2020 recorded cost due to a declining, variable trend in the data.

76. The 2023 expense forecast for GT&S Operations (MAT CMA) of $15.360 million is reasonable because it is more consistent with average costs during the 2016-2021 time period.

77. The 2023 expense forecast for Electric Power for Compressor Fuel and Other Equipment (MAT CMB) of $27.500 million is reasonable as it is based on costs during 2016-2020 time period.

78. The revised 2023 capital forecast for Supervisory Control and Data Acquisition (SCADA) Visibility Program – Gas Transmission Remote Terminal Units (Capital MAT 76M) of $2.778 million is reasonable as it is based on adding eight SCADA.

79. PG&E's forecast for capital expenditures for Supervisory Control and Data Acquisition (SCADA) Visibility Program – Gas Distribution Remote Terminal Units (Capital MAT 4AM) is not adequately supported by the evidence, include by risk mitigation benefits or the cost-effectiveness of the activity and, instead, it is reasonable for no capital expenditure be included for this activity in this rate case period (2023-2026).

80. A 2023 capital forecast for Gas Transmission Capacity for Load Growth (MAT 73A) of $6.028 million is reasonable as it is based on data during the 2018-2020 period.

Section 3.11 Gas Technology

81. The 2023 expense forecast for the Gas Research and Development and Deployment Program (MAT GZA) of $7.414 million is reasonable as it is based on costs in the last recorded year of 2020 being the most known and measurable.

Section 3.12 Other Gas Operations Support

82. The 2023 capital forecasts for the StanPac Transmission Pipeline (MAT 44A) of $2.887 million in 2023, $2.880 million in 2024, $15.245 million in 2025, and $15.736 million in 2026 are reasonable as these adjustments are consistent with adjustments adopted for other transmission pipe programs.

83. The 2023 expense forecasts for the StanPac Transmission Pipeline (MAT 34A) of $2.505 million is consistent with adjustments adopted for other transmission pipe programs and is reasonable.

Section 3.13 New Business and Work at the Request of Others

84. The 2023 expense forecast for Gas Transmission Work at the Request Of Others (Expense MAT JTA) of $0.510 million is reasonable as it is based on the average of recorded costs for the more recent five year period of 2016-2021.

85. PG&E's 2023 capital forecast for the Gas Distribution New Business Program (MWC 29) of $7.923 million is reasonable because (1) PG&E expects to incur costs for gas transmission project allowances related to applications received before July 2023 throughout the 2023-2026 period, and (2) the Large Gas Solutions Program is creating a higher level of new business activity than in past rate case periods.

86. The 2023 capital forecast for Gas Transmission Work at the Request Of Others Program (MAT 83A) of $16 million is based on a five-year historical average (2015 through 2019) of actual net capital expenditures for this program minus the removal of $5.5 million for the unlikely performance of the Department of Water Resources Delta Conveyance Project and is reasonable.

Section 4 Electric Distribution

Section 4.1 Overview Section

87. PG&E's proposed wildfire risk reduction activities are a major driver in the cost forecast for the Electric Distribution line of business.

88. PG&E's electric distribution system is essential in the provision of a basic public service, electric service but carries with it inherent risk.

89. PG&E's approach to provision of electric service must mitigate the grave risks posed by wildfire to Californians' safety, health, and property.

90. Reducing the risk of harm is necessary and can be costly.

Section 4.2 Wildfire Risk Mitigation Forecast

91. Within Wildfire Risk Mitigation, PG&E forecasts the majority of 2023-2026 capital expenditures for System Hardening (PG&E's undergrounding, covered conductor proposals, and other lesser costs, approximately $6.4 billion ($5.9 billion for capital for undergrounding and $517 million capital for covered conductor), and a 2023 expense forecast of approximately $11.595 million.

Section 4.3 Wildfire System Hardening

92. PG&E's System Hardening forecast focuses on mitigating wildfire risk posed by distribution overhead assets in and near Tier 2 and 3 HFTDs in its service territory.

93. Undergrounding, and to a much lesser degree covered conductor, make up a significant portion of the System Hardening forecasts.

Section 4.3.2 System Hardening Forecast – Undergrounding and Covered Conductor

94. PG&E plans to rely on EPSS and PSPS in times of increased fire risk while underground construction is underway.

Section 4.3.3 Risk Mitigation of Fire Ignition from Electric Overhead Infrastructure

95. Undergrounding a distribution line substantially reduces the risk of wildfire ignition.

96. The risk of wildfire must be reduced and the harm caused by wildfire can be catastrophic.

97. Risk reduction alone is not a sufficient metric to judge the prudency of proposed mitigations.

98. It is reasonable to find that ratepayers' ability to pay for safety or risk reduction is not unlimited; as with all safety measures, the Commission must consider the cost and impact on affordability.

Section 4.3.4 Costs of Undergrounding as Compared to Covered Conductor

99. A $1.261 million per mile for 2023 with escalating costs for 2024-2026 for installation of covered conductor presents a reasonable estimate for wildfire mitigation aspects of the installation of covered conductor, and a reasonable middle ground between TURN and PG&E's proposals.

100. Given PG&E's aging infrastructure, there is value in doing all work needed at a given site while work crews are out at such site. A unit cost of $1.261 million per mile in 2023, increasing over this rate case period to approximately $1.396 million per mile in 2026 for purposes of installation of covered conductor is a reasonable reflection of the appropriate level of potential costs.

101. A unit cost of $1.261 million for covered conductor strikes an appropriate balance between funding needed onsite asset replacement work and containing costs.

102. PG&E's 1.25 conversion factor is reasonable for the purpose of establishing a reasonable cost estimate for undergrounding.

103. PG&E's estimates of decreasing undergrounding costs over time requires testing before approving the project at a larger scale.

104. PG&E's 2023 estimated costs per mile for undergrounding of approximately $3.3 million per mile in 2023, decreasing over this rate case period to approximately $2.8 million in 2026 (four-year average cost of $2.97 million) is reasonable.

105. TURN and PG&E presented different evidence on the appropriate levels and methods of system hardening.

106. More risk reduction is achieved when covered conductor and undergrounding work is conducted in the highest risk areas.

107. A 'covered conductor buffer' may yield less risk reduction than a strict limit on covered conductor projects, but it allows PG&E to address practical project planning and execution challenges along with mitigating risks not addressed by the risk models.

108. A "hybrid scenario" with 973 miles of undergrounding, 881 miles of covered conductor, and 146 miles of "covered conductor buffer" can capture cost savings while still achieving a high level of risk reduction.

109. The forecasted capital cost of the "hybrid scenario" is $4.270 billion and is reasonable, and is $2.173 billion less than PG&E's proposal.

Section 4.3.5 Projected Total Costs and Customer Affordability

110. As compared to TURN's alternative recommendation of approximately $2.1 billion (2023-2026) and the "hybrid scenario" of approximately $4.270 billion, PG&E's capital forecast of approximately $5.9 billion plus additional expenses (2023-2026) will present challenges for customers regarding affordability. Given the nascent stage of PG&E's undergrounding ambitions, the "hybrid scenario" offers an opportunity for PG&E to prove that it can perform undergrounding projects at scale in a timely manner while achieving forecast unit cost reductions.

111. The "hybrid scenario" appropriately balances costs, risk reduction, timeliness, and feasibility

Section 4.3.6 Pace of Undergrounding as Compared to Covered Conductor

112. Future GRC or other cost recovery applications will benefit from actual cost and construction data for undergrounding at a larger scale.

Section 4.3.7 Accountability

113. There is uncertainty associated with large scale undergrounding.

114. PG&E's proposed scope of undergrounding is significantly greater than what it has performed to date. PG&E should have an opportunity prove how well it can underground lines in a way that effectively reduces risk and manages costs.

115. Information filings ordered by this decision may help inform review of any future requests made by PG&E for ratepayer funding for undergrounding.

116. Future forecasts of unit costs and pace of work will be informed by historic actual data.

117. The Commission has reviewed whether additional costs incurred to implement wildfire risk mitigation above the amounts authorized for rate recovery in the GRC are just and reasonable through after-the-fact reviews. While this structure allows an electrical corporation the opportunity to collect additional revenues above and incremental to the revenue requirement authorized in a GRC, it also requires the Commission to ensure an electrical corporation does not recover additional revenue for wildfire risk mitigation activities unless those activities are incremental to the work authorized in its GRC.

Section 4.3.8 Construction Feasibility of PG&E's Proposal to Underground 2,000 Miles in 2023-2026

118. PG&E has increased the pace of undergrounding in recent years, but at a smaller scale than its proposal would reflect.

119. In 2022, PG&E undergrounded 180 miles, and in 2021 it undergrounded 73 miles.

120. Authorizing 972 miles of undergrounding in the "hybrid scenario" is an appropriate middle ground between PG&E's and TURN's proposals.

Section 4.3.9 Risk-Spend Efficiency Modelling

121. The Commission has adopted a risk-based decisionmaking framework, including risk reduction and risk spend efficiency analysis, to evaluate the reasonableness of competing safety-related investment proposals.

Section 4.3.11 System Reliability - Potentially Less Power Shutoffs due to Overhead Infrastructure Damage and Less Reliance on PSPS/EPSS

122. Increased undergrounding, especially on the magnitude suggested by PG&E, may result in PG&E's decreased reliance on PSPS and EPSS, as compared to now, for purposes of wildfire mitigation.

Section 4.3.12 Discussion

123. PG&E's uncontested 2023 expense forecast for System Hardening of $11.595 million is reasonable.

124. Based on the significant unknowns and unaddressed concerns regarding PG&E's ability to successfully implement its proposal in a timely manner together with the steep costs, PG&E's $6.4 billion forecast for System Hardening (undergrounding and covered conductor) is unreasonable at this time.

125. The $4.270 billion for capital expenditures for System Hardening consists of a forecast of $1.369 billion for overhead hardening and a forecast of $2.901 billion for undergrounding. The $1.369 billion of capital expenditures for overhead hardening are as follows: $323,827,628 (2023); $338,161,874 (2024); $348,165,802 (2025); and $358,469,922 (2026). The $2.901 billion of capital

expenditures for undergrounding are as follows: $488,157,244 (2023); $630,577,194 (2024); $760,910,771 (2025); and $1,021,075,674 (2026).

Section 4.4 Other Wildfire Risk Mitigations Section

Section 4.4.1 Situational Awareness and Forecasting Section

126. PG&E's uncontested 2023 Situational Awareness and Forecasting expense forecast of $43.416 million (MWC AB) and capital expenditures request of $9.451 million in 2021, $9.375 million in 2022, and $4.601 million in 2023 (MWC 21) is reasonable.

Section 4.4.2 Public Safety Power Shutoff Operations

127. It is reasonable to find that 2019 was an anomalous year for costs related to PSPS Operations because 2019 was the first year PG&E relied upon PSPS as a wildfire mitigation strategy and, during 2019, PG&E built the operational foundation to support turning off power for wildfire risk mitigation.

128. It is reasonable to find that the scope and duration of PG&E's activities to support PSPS Operations in 2019 and the high number of PSPS events in 2019 should not be repeated in the forecast years because the program is now created and PG&E has taken steps to minimize its use of PSPS, seeking to ensure PSPS events are narrowly tailored and short in duration.

129. Because 2019 was an anomalous year for PG&E's use of PSPS and PG&E has taken steps to minimize the use of PSPS, a 2023 expense forecast of $83.798 million for PSPS Operations (MWC AB) is reasonable that take into consideration TURN's recommended reduction of $31 million to PG&E's 2023 expense forecast of $115.266 million.

130. PG&E's capital expenditure request for PSPS Operations of $3.084 million in 2021, $3.237 million in 2022, and $262,000 in 2023 (MWC 21) is reasonable

within the context of the rapid initiation of this newer mitigation measure with the subsequent decreasing costs.

Section 4.4.3 Enhanced Automation and PSPS Impact Mitigation

131. Regarding the MAT 2AP Expulsion Fuse Replacement, it is reasonable for PG&E's capital expenditure forecast to include work to replace non-exempt expulsion fuses, while PG&E continues to resolve the potential defects, which PG&E describes as equipment that may "generate electrical arcs, sparks, or hot material during its normal operation … [that] could cause an ignition."

132. PG&E's capital expenditures request for MAT 2AP Expulsion Fuse Replacement of $15.125 million in 2021, $15.388 million in 2022, and $15.752 million in 2023 is reasonable.

133. Regarding the MAT 49I Distribution Grid Sensors, it is reasonable for PG&E to replace defective equipment while PG&E continues to resolve the potential product defect issues.

134. PG&E's capital expenditure request of $12.369 million in 2021, $23.036 million in 2022, and $22.653 million in 2023 for MAT 49I Distribution Grid Sensors is reasonable based on its projected work and forecasting method.

Section 4.4.4 Community Wildfire Safety Program Project Management

135. PG&E's uncontested 2023 expense forecast of approximately $13.5 million regarding the Community Wildfire Safety Program Project Management Organization is reasonable and no capital expenditure request is presented.

Section 4.4.5 Information Technology for Wildfire Mitigations

136. PG&E's 2023 uncontested expense forecast for Information Technology for Wildfire Mitigations of $35.700 million is reasonable.

137. PG&E's uncontested capital expenditure requests regarding Information Technology for Wildfire Mitigations of $25.300 million in 2021, $25.300 million in 2022, and $25.300 million in 2023 is reasonable.

Section 4.4.6 Enhanced Powerline Safety Settings

138. PG&E fails to support a persuasive 2023 forecast for expense of $151.129 million based on the lack of specificity and flaws in the cost forecast for Additional Patrols.

139. TURN's recommendation to reduce PG&E's EPSS 2023 expense forecast to $87.049 million is found reasonable which is based on a convincing calculation of circuit miles and need for Additional Patrols.

140. PG&E requested no capital expenditures for EPSS and explains that such costs will be incurred but are too uncertain to forecast presently.

141. It is reasonable for PG&E to continue to refine EPSS program implementation and pursue opportunities to use new technologies and efficiencies to narrowly tailor its EPSS program and improve restoration times.

Section 4.5 Emergency Preparedness

142. The Commission finds reasonable PG&E's uncontested capital expenditure requests of $2.109 million in 2021, $2.143 million for 2022, and $6.477 million for 2023 for Emergency Preparedness and Response.

Section 4.6 Electric Emergency Recovery

Section 4.6.1 Routine Emergency Capital (MWC 17) and Major Emergency Capital (MWC 95)

143. PG&E's capital expenditure forecast for MWC 17 Routine Emergency and MWC Major Emergency of $277.941 million for 2021, $339.418 million for 2022, and $360.523 million for 2023 are reasonable as the forecasts are based on a three-year average of costs during 2018-2020.

Section 4.6.2 Catastrophic Event Straight Time Labor Costs and CEMA Events

144. Cal Advocates' recommendation to remove $20.079 million associated with PG&E's forecast for Catastrophic Events Memorandum Account (CEMA) straight-time labor costs from PG&E's Major Emergency Expense (MWC IF) forecast is reasonable.

145. After deducting the amount of $20.079 million, an expense forecast for MWC IF Major Emergency Expense in 2023 of $42.709 million is reasonable.

146. Removal of the forecasts for Catastrophic Events Memorandum Account straight-time labor is reasonable as follows: (1) 2023 expense forecast for MWC IG (Customer Care) is reduced by $144,000, expense forecast for MWC LX (Gas Operations) is reduced by $2.878 million, expense forecast for MWC LX (Generation) is reduced by $84,000, and (2) 2023 capital forecast for MWC 95 (Electric Distribution) is reduced by $16.375 million, capital forecast for MWC 3Q (Gas Operations) is reduced by $2.098 million, capital forecast for MWC 3Q (Generation) is reduced by $121,000.

Section 4.6.3 Catastrophic Event Straight Time Labor Balancing Account

147. PG&E has not demonstrated a reasonable justification for establishing a new two-way balancing account, which PG&E refers to as the Catastrophic Event Straight Time Labor Balancing Account.

Section 4.6.4 Documentation of CEMA Costs

148. Additional information regarding PG&E's adjustments to remove Catastrophic Event Memorandum Account costs recorded to MWC IF Major Emergency Expense and MWC 95 Routine Emergency Capital would clarify PG&E's requests for cost recovery.

Section 4.7 Distribution System Operations

149. PG&E's 2023 uncontested expense forecast of $60.531 million for Distribution System Operations is reasonable.

Section 4.8 Field Metering

150. TURN's recommended 2023 expense forecast for MAT IU Field Metering Revenue Collection Program of $1.58 million is reasonable because it is based on historical data indicating a decline in PG&E energy theft investigations from 2017 to 2021.

Section 4.9 Vegetation Management

Section 4.9.1 Tree Mortality Program

151. PG&E's uncontested 2023 Tree Mortality Program forecast of $70.771 million is reasonable.

Section 4.9.2 Routine and Enhanced Vegetation Management

152. PG&E's 2023 forecast for Routine Vegetation Management (MWC HN) of approximately $1.31 billion for the MWC HN Routine Vegetation Management, including subaccounts, MAT IGJ Enhanced Vegetation Management and MAT IGI Tree Mortality Work is reasonable because it is based on 2020 recorded costs, which were significantly higher than prior recorded costs but likely reflective of future costs.

Section 4.10 Overhead and Underground Electric Asset Inspections

153. The uncontested forecasts for expense tracked in MWC BF Overhead and Underground Inspections and Patrols set forth at Appendix A of PG&E's Opening Brief at A-17 and A-25. are reasonable. PG&E present no capital expenditure forecasts associated with Overhead and Underground activities.

Section 4.10.1 Overhead Inspections

154. PG&E's argument that its change in inspection criteria "suddenly" increased the number of poles tagged for corrective action by approximately four times the average annual inspection find rate in pre-WSIP years is not persuasive.

155. PG&E also has not quantified the backlog or the number of poles tagged for correction that existed prior to the adoption of WSIP in 2019.

156. TURN's recommended 2023 forecast for MAT BFB Overhead Inspections of $49.148 million, which is based on reducing PG&E's 2023 expense forecast by $9.659 million to account for the costs of Field Safety Reassessment pertaining to pole replacement that would not be required but for PG&E's work backlog, is reasonable.

Section 4.11.2 Unit Cost of Overhead and Underground Electrical Distribution Maintenance

157. A two-way Electric Distribution Maintenance Balancing account would protect ratepayers from paying the cost of untracked deferred work in this area and allow PG&E the flexibility to perform the work it can cost-effectively perform.

Section 4.11.3 Overhead Equipment Replacement Expense Forecast (MWC KA)

158. TURN's recommended 2023 expense forecast for MAT KAA Overhead Notification and Repair Program of $20.267 million, which is based on reducing to PG&E's forecast for MAT KAA Overhead Repair Program by $38.1 million to account for PG&E's unit costs impacted by PG&E's unwarranted backlog of related maintenance work, is reasonable.

Section 4.11.4 Overhead Preventive Maintenance and Equipment

159. PG&E's forecast for MAT 2AA Overhead Notifications Program is not persuasive because PG&E has not addressed how its forecast reflects its plans to reduce costs by hiring more employees and completing work with less costly overtime and contract labor.

160. Cal Advocates recommends 2023 forecasted expense for the MAT 2AA Overhead Notifications Program of $133.0 million is persuasive using a lower unit cost of $6,806 per notification and use of less overtime labor and fewer outside contractors.

161. PG&E's capital expenditure request for MAT 2AB Bird Safe Installation and Replacement Program of $3.023 million for 2021, $3.841 million for 2022, and $3.474 million for 2023 is reasonable as it is based on 2019-2020 recorded costs.

162. PG&E plans to increase the priority of corrective notices or tags for the work tracked in MAT 2AC Bird Safe Retrofits Program resulting in more work in a shorter time.

163. PG&E's capital expenditures request for MAT 2AC Bird Safe Retrofits Program of $3.432 million in 2021, $3.626 million in 2022, and $3.615 million based on PG&E's increased pace of work is reasonable.

164. PG&E's capital expenditures forecast of $20.5 million in 2021, $2.732 million in 2022, and $2.726 million in 2023 for MAT 2AF Idle Facilities Removal Program, which supports work to reduce risks of ignition and system hardening, is reasonable.

165. PG&E's $1.0 million request for 2023 capital expenditures for the Non-Wood Streetlight Replacement Program is a $700,000 increase over 2020 recorded capital expenditures is not persuasive.

166. Cal Advocates' recommended forecasts for 2023 capital expenditures of $800,000 for the Non-Wood Streetlight Replacement Program and $350,000 for the Equipment with Access Issues Program for a total forecast of $1.150 million is reasonable based on PG&E's average annual pace of spending from 2019-2021, including approximately $0 in 2020 for Non-Wood Streetlights.

167. PG&E's capital expenditure request for the MAT 2AQ Ceramic Post Insulator Replacement Program of $3.960 million in 2021, $5.832 million in 2022, and $5.821 million in 2023 is reasonable because it reflects increased work in Tier 2 and 3 HFTDs, increased work in the MAT 2AR Non-Exempt Surge Arrester Replacement Program in 2021, and a plan to perform work independent of the surge arrestor replacement work in 2022.

168. PG&E's capital expenditure request for MAT 2AS Field Automation System Overhead Capital Program of $639,000 for 2021, $831,000 for 2022, and $830,000 for 2023 is reasonable because it is consistent with PG&E's plans to increase maintenance of overhead electrical distribution maintenance.

169. PG&E's Non-Exempt Surge Arrester Replacement Program (MAT 2AR) capital expenditure forecast of $88.859 million in 2021, $16.804 million in 2022, and $17.759 million in 2023 is reasonable as it is based on reducing the risk of electrical arcs, sparks, or other hot material during the operation of electrical lines even if in non-HFTDs.

Section 4.11.5 Underground Equipment Replacement

170. PG&E's request for capital expenditures for MAT 2BA Underground Notifications Program of $46.680 million in 2021, $46.391 million in 2022, and $47.807 million in 2023, which is based on additional work identified for regulatory compliance and an increase in the cost of work on larger enclosures containing high-voltage cables, is reasonable.

171. PG&E's capital expenditures request for MAT 2BD Underground Critical Operating Equipment Program of $6.573 million in 2021, $6.354 million in 2022, and $6.926 million in 2023 based on the 2018-2019 two-year average of the find rate plus additional units for open or pending jobs is reasonable.

172. PG&E's capital expenditure request for MAT 2AH LED Streetlight Conversion Program of $1.028 million in 2021, $2.116 million in 2022, and $7.1 million in 2023 forecast is reasonable as it is based on an estimated increase in demand for conversions due to a decrease in the incremental facility charge.

173. A capital forecast for the San Francisco Incandescent Streetlight Replacement Program (MAT 2AG) of $0 in 2021, $0 in 2022, $2.5 million in 2023, and $2.6 million in 2024 is reasonably based on PG&E not performing work in this program in 2021-2022, restarting work in 2023 and completing the program in 2024.

Section 4.12 Pole Asset Management

174. Regarding the uncontested forecasts for 2023 expense and 2021, 2022, and 2023 capital expenditures for PG&E's Pole Asset Management Program are reasonable.

Section 4.12.1 Prior Pole Replacement

175. PG&E's enhancement of its inspection program was long overdue and the deferral of pole replacement work since at least 2003 has contributed to PG&E's current backlog of this work, which has developed over years, not suddenly.

Section 4.12.2 Pole Replacement Programs (MAT 07D, MAT 070, and MAT 07C)

176. Cal Advocates' 2023 capital expenditures request for the Pole Replacement Programs, including $337.48 million for MAT 07D, $7.18 million for MAT 07O and $3.02 million MAT 07C are reasonable as PG&E's requests are based on

historical unit costs, a manageable future pace of work, and estimated future unit costs that are not excessive.

Section 4.12.3 Pole Replacement Forecasts for 2021 and 2022

177. PG&E's capital request includes costs for pole replacements for 2021 and 2022 that are included in the Wildfire Mitigation Plan Memorandum Account prior to a reasonableness review by the Commission.

Section 4.13 Overhead and Underground Asset Management and Reliability

178. The uncontested capital expenditures requests (MWC 08, MWC 49, and MWC 56) for PG&E's Overhead Asset Management and Underground Asset Management set forth at Appendix A of PG&E's Opening Brief at A-17 and A-25 are reasonable.

Section 4.13.1 Electric Distribution Overhead Asset Replacement (Capital MWC 08)

179. PG&E's capital expenditure request for its Overhead Conductor Replacement Program (MAT 08J) of $41.2 million in 2021, $32.7 million in 2022, and of $43.0 million in 2023 based on performing work necessary to maintain safety and to ensure system reliability is reasonable.

180. Cal Advocates' recommended capital forecasts for PG&E's Overhead Switch Replacement Program (MAT 08S) of $0.925 million of 2021, $0.949 million for 2022, and $0.3 million for 2023 based on actual historical replacement rates and the useful lives of this equipment are reasonable.

181. The uncontested aspects of requests for capital expenditures related to MWC 49 Distribution Circuit Zone Reliability set forth at Appendix A of PG&E's Opening Brief at A-17 and A-25 are reasonable.

182. PG&E's requested capital forecast for PG&E's Overhead Fuse Program (MAT 49C) of $0.882 million in 2021, $1.5 million in 2022, and $1.560 million in

2023 is based on an achieved rate of replacement for this equipment is reasonable because it is consistent with promoting safety and reliability.

Section 4.13.3 Electric Distribution Underground Asset Replacement

183. PG&E's capital forecasts for the MAT 56A Reliability Related Cable Replacement program of $38.013 million in 2021, $39.556 million in 2022, and $36.976 million in 2023 are reasonably necessary to maintain system reliability.

184. PG&E's capital expenditure request for MAT 56C Critical Operating Equipment Cable Replacement Program of $34.260 million in 2021, $33.030 million in 2022, and $36.002 million in 2023 are reasonably necessary and shall be tracked in a two-way balancing account to provide PG&E with the flexibility to complete the amount of work that is necessary and to protect ratepayers when the work is not performed, funds for reliability conductor replacement.

185. PG&E's capital expenditure request of $9.252 million for 2021, $9.493 million for 2022, and $8.1 million for MAT 56S LBOR Switch Replacement is reasonable because it is needed to maintain worker safety and to maintain reliability.

186. The capital forecast recommended by Cal Advocates for MAT 56T Temperature Alarm Devices of $8.928 million in 2021, $3.075 million in 2022, and $8.5 million in 2023 is reasonable because it is based on 2019-2020 data, not anomalous data from 2018.

Sections 4.14-4.18 Electric Substations

187. PG&E's capital forecast for the combination of Install/Replace Network Assets (MWC 2C) and Electric Distribution UG Asset Replacements (MWC 56), of the $41.1 million for 2021, $44.0 million for 2022, and $44.4 million for 2023

supports replacing deteriorated or obsolete electric distribution network equipment to maintain safety and reliability is reasonable.

188. PG&E's capital forecast for its Circuit Breaker Replacement Program (MAT 48D) of $14.3 million for 2021, $31.3 million for 2022, and $28.6 million in 2023 aligns safety, reliability, and other benefits with a more proactive and reasonable circuit breaker replacement rate and is reasonable.

189. PG&E's capital expenditures forecast for the Switch Replacement Subprogram (MAT 48E) of $945,000 in 2021, $3.457 million in 2022, and $2.166 million in 2023 aligns safety, reliability and other benefits with a more proactive switch replacement rate and is reasonable.

190. PG&E's capital expenditures forecast for MAT 48X Animal Abatement of $4.533 million in 2021, $5.404 million in 2022, and $5.760 million for 2023 aligns safety, reliability and other benefits with a more proactive approach and is reasonable.

191. PG&E's 2023 capital expenditure forecast for MAT 48C Battery Replacement of $200,0000 in 2021, $3 million in 2022, and $3.3 million in 2024 is reasonable because proactive replacement of these components avoids the negative reliability consequences of failures and provides flexibility in accommodating supply chain and other delivery issues with these components.

192. PG&E's capital expenditures forecast for MAT 48L Line Work Support of $24.931 million in 2021, $6.027 million in 2022, and $9.105 million in 2023 is reasonable because a robust proactive replacement program for these types of assets appears critical to maintaining reliability and public safety.

193. PG&E's capital expenditures for MWC 48 Replace Substation Equipment of $76.601 million for 2021, $96.588 million for 2022, and $96.331 million for 2023 are reasonable to maintain safety and reliability.

194. PG&E's capital expenditures for the work tracked in Other Equipment Replacement Work of $5.858 million for 2021, $19.608 million for 2022, and $17.218 million for 2023 are reasonable to maintain safety and reliability.

195. PG&E's 2023 capital forecasts for Distribution Transformer Replacements for MWC 54A and MWC 54L of $40.766 million in 2021, $27.970 million in 2022, and $21.243 million in 2023 are based on a proactive replacement program for these types of assets to maintain reliability and public safety and are reasonable.

196. PG&E's 2023 capital forecast for the Fire Protection and Suppression subprogram (MAT 58A) of $3.3 million is reasonable.

197. PG&E's capital expenditures for MWC 58 Distribution Transformer Replacement of $5.980 million for 2021, $1.738 million for 2022, and $8.232 million for 2023 meets the forecasted needs for substation security and is consistent with Commission directives regarding substation security and is reasonable.

198. PG&E's capital forecasts for the Electric Distribution Capacity Program (MWC 46 and MWC 06) of $286.313 million in 2021, $215.512 million in 2022, and $195.7 million in 2023 are reasonable considering currently identified and emergent electrical distribution capacity needs.

199. PG&E's 2023 capital forecast for Residential Connects (MWC 16) of $261.565 million, based on PG&E's projection of 57,434 new connections, is reasonable.

200. PG&E's 2023 capital forecast for Non-Residential Connects (tracked within MWC 16) of $192.848 million is based on an increased trend in Non-Residential Connects and is reasonable.

201. A 2023 capital expenditure forecast for Plug-In Electric Vehicles (MWC 16) of zero dollars is reasonable due to uncertainty regarding PG&E's forecast arising from PG&E's Petition for Modification of D.22-12-054.

202. PG&E's capital forecast Distribution Transformer Purchases of $141.570 million in 2021, $151.725 million in 2022, and $169.068 million is consistent with adopted forecasts for Pole Replacements (MWC 07), New Business (MWC 16) and Major Emergency (MWC 95) and is reasonable.

Section 4.19 Tariff Rule 20A

203. TURN's recommended capital expenditures forecast of $37.8 million for 2021, $28.2 million for 2022, and $29.2 million for in 2023 for MWC 30 Electric Rule 20A uses a five-year (2017-2021) average accounts for price changes over time and offers the more reasonable forecast than PG&E's because the proposals don't adequately address PG&E's history of underspending relative to forecast for Rule 20A conversion projects and whether Rule 20A funds are being cost-effectively spent.

Section 4.20 Electric Distribution Data Management and Technology

204. The combined total Electric Distribution capital forecast for MWC 2F and MWC 21 of $17.696 million for 2021, $23.605 million for 2022, and $19.700 for 2023 is uncontested and reasonable.

205. To inform future improvements and visibility into PET analysis, it is reasonable to direct PG&E in future general rate cases to provide an explanation and workpaper justification, for each manual override performed on PET estimates, which at a minimum explain why the PET manual override more accurately estimates costs.

206. A reduction to PG&E's 2023 forecast for MWC GE Electric Distribution Mapping of $21.524 million by $3.915 million for the Next Gen GIS project

component of the GIS Asset Data Improvements is reasonable based on PG&E failure to justify.

207. A reduction is reasonable and results in a total 2023 expense forecast for MWC GE Electric Distribution Mapping of $17.609 million: $0.391 million for Base Mapping, $6.765 million for GIS Technical Enhancements, $5.253 million for Data Management and Analytics, and $5.2 million for the adequately supported portions of GIS Asset Data Improvements.

208. A reasonable expense forecast for 2023 for Electric Distribution Mapping (MWC GE) of $17.609 million.

209. The Commission finds PG&E's budget-based expense forecast anticipated for 2023 of $4.501 million reasonable as it is persuasive and more appropriate, in this instance, than Cal Advocates historic three-year average.

210. PG&E's uncontested 2023 forecast to be reasonable and adopts an expense forecast for MWC JV Maintain IT Applications and Infrastructure in 2023 of $4.501 million.

Section 4.21 Integrated Grid Platform and Grid Modernization Plan

211. In response to D.21-11-028, PG&E removed $15.1 million for the Technology Demonstration Project Work and this $15.1 million removal was the entire 2023 expense forecast for the Emerging Technology Projects component of MWC AT.

212. The remainder of PG&E's request of $2.056 million reflects its forecast for the External Innovation Partnership subprogram and its administration, which is not funded through EPIC.

213. PG&E's reduced 2023 expense forecast of $2.056 million for MWC AT Electric Emerging Technology Program is reasonable.

214. Consistent with the Commission's direction in D.18-03-023, considering the costs of $27.735 million for ADMS Release 3 and DERMS associated with their proposed removal in this general rate case is appropriate and reasonable.

215. The removal of the cost of ADMS 3 and DERMS from PG&E's request and Cal Advocates' recommended reduction of $27.735 million from PG&E's 2023 forecast for ADMS Release 3 and DERMS associated with their proposed removal.

216. A reduced forecast could delay the functionality, which could be detrimental to a high DER future and, for these reasons, the Commission does not reduce PG&E's capital expenditure forecast for 2023 for the ADMS program by the $24.9 million recommended by Cal Advocates.

Section 4.22 Electric Distribution Support

217. PG&E's uncontested Electric Distribution Support capital expenditures forecast for MWC 05 Tools and Equipment and MWC 21 Miscellaneous Capital is $18.340 million in 2021, $10.663 million in 2022, $8.394 million in 2023 is reasonable.

218. Cal Advocates' recommendation to rely on a five-year average is convincing and reasonable. While PG&E explains how Miscellaneous Expense has evolved to support a "bottoms-up" expense forecast for 2023, PG&E provides insufficient information to substantiate its forecast for 2023 Miscellaneous Expense, which is over twice the average recorded cost of 2016-2019.

Section 4.23 Community Rebuild Program – Town of Paradise

219. The cost recovery for Community Rebuild Expenditures for 2019-2020 excludes costs disallowed by the Wildfire Order Instituting Investigation (I.19-06-015) in accordance with D.20-05-019 and System Hardening costs

recorded to MWC 08W through December 31, 2020 included in the 2020 Wildfire Mitigation Catastrophic Events Application (A.20-09-019).

220. PG&E's position regarding the costs of the Community Rebuild Program related to the 2018 Camp Fire in and around the Town of Paradise and the other costs, such as the Butte Wildfire rebuild, reflected in PG&E Ex-04 at WP Table 23-13 is not persuasive.

221. A reasonableness review applies prior to PG&E recovering 2018-2022 costs.

222. It is reasonable to deny PG&E's request to seek to recover costs related to the 2018 Camp Fire within the framework of a general rate case on a forecast basis or without a prior reasonableness review.

223. All costs related to the "rebuild" shall be interpreted broadly and consistent with the statute to include restoring, repairing, replacing, and complying with government standards for the infrastructure destroyed in the 2018 Camp Fire and shall be presented to the Commission for a reasonableness review consistent with Pub. Util Code Section 454.9.

224. Pub. Util. Code Section 454.9 does not limit the type of costs that the Commission may review in a CEMA account, in the manner suggested by PG&E, to only include costs to replace the exact type and quality of equipment destroyed, and instead specifically refers to a broad range of some of the potential types of costs.

225. It is reasonable to require PG&E to continue to submit costs incurred under its Community Rebuild Program under the CEMA framework under Pub. Util. Code Section 454.9 subject to after-the-fact reasonableness review.

226. It is reasonable to reject PG&E's position that the cost forecasts for the Community Rebuild Program from 2023-2026 should not be subject to CEMA

cost recovery because PG&E's argument that these costs relate to activities beyond traditional CEMA restoration work, to include undergrounding work that will provide superior and longer-lasting benefits to customers, is not persuasive.

227. The Oakland firestorm case PG&E cites, D.92-12-016, is inapplicable here; while it is true the Commission denied undergrounding costs as part of PG&E's CEMA request, it did so because it found the affected community should pay for the undergrounding under Rule 20, which is not relevant here.

228. If PG&E has committed to undergrounding assets that were not underground prior to the 2018 Camp Fire in connection with the restoration of service in Paradise, that does not limit the Commission from evaluating the reasonableness of such costs pursuant to Pub. Util. Code Section 454.9.

229. The costs that PG&E incurs in connection with rebuilding the Town of Paradise must be reasonable according to current best practices.

230. A single CEMA application is Commission is not required.

Section 4.24 Electric Distribution Ratemaking

231. Because PG&E indicates that the most significant costs tracked in the WMBA, System Hardening - undergrounding, are projected to decline during the rate case period, PG&E's projected declining costs for wildfire mitigation in PG&E Ex-04 are not consistent with the purpose of the current structure of the balancing account and it is reasonable to find insufficient evidence of "uncertainty" to continue the WMBA in its current format, as authorized in D.20-12-005.

232. PG&E may seek continuation of the WMBA in its 2027 general rate case if PG&E considers the continuation of the WMBA useful beyond 2026.

233. Because PG&E is now well-experienced at an increased level of vegetation management, including Enhanced Vegetation Management plus its routine vegetation management, with PG&E implementing increased vegetation management as a wildfire mitigation since at least 2018, it is reasonable to find PG&E has failed to provide persuasive evidence to support the continuation of the VMBA as a two-way balancing account with an increased reasonableness review threshold of 125%.

234. The continuation of the VMBA is appropriate to account for remaining external uncertainties is reasonable but a one-way balancing account is sufficient and a reasonableness review threshold is no longer appropriate because PG&E's forecasts rely upon at least 4-5 years of data and PG&E has reached a higher level of sophistication, generally, regarding vegetation management within the context of climate change.

Section 5 Energy Supply

235. The provision in the November 21, 2022 Cal Advocates-PG&E Energy Supply Stipulation that presents a reduced PG&E 2023 expense forecast of $2.445 million by removing the cost of additional staff is reasonable. Similarly, PG&E and TURN resolved this staffing issue in the November 21, 2022 TURN-PG&E Energy Supply Stipulation and this result is reasonable.

236. PG&E's stipulation is reasonable with TURN and Cal Advocates for a reduction of $4.7 million to PG&E's 2023 forecast for setting Large Uncontrolled Water Release risk costs equal to the 2020 RAMP forecast and, in addition, for a reduction of $1.3 million in 2023 in response to the disputed headcount, resulting in a 2023 expense forecast for Hydro Operations of $171.9 million.

237. PG&E's undisputed 2023 expense forecast for Natural Gas and Solar of $52.258 million is reasonable.

238. On September 2, 2022, Senate Bill 846 provided for the possible continued operation of the Diablo Canyon Power Plant beyond the expiration dates of the operating licenses and up to five additional years under specified conditions.

239. Because PG&E's rate case application was filed before the passage of Senate Bill 846, PG&E's capital and expense forecasts for Diablo Canyon Power Plant presented in this proceeding do not reflect a possible change in the operational status of the plant, as contemplated by Senate Bill 846 and PG&E's cost request in this rate case reflect the shutdown dates of November 2024 (Unit 1) and August 2025 (Unit 2).

240. Because the Commission is currently considering next steps toward initiating the new Diablo Canyon Power Plant-specific cost recovery proceeding in R.23-01-007, the successor proceeding to A.16-08-006 (the proceeding addressing the potential continued operations of the Diablo Canyon Power Plant, per Senate Bill 846), it is reasonable to limit consideration in this proceeding to the cost requests as presented by PG&E's June 30, 2021 Application.

241. The provision in the November 21, 2022 TURN-PG&E Energy Supply Stipulation which agrees to a reduction in PG&E's 2023 expense forecast for Nuclear Operations by $9.2 million by resolving the head count assumptions in PG&E's labor expense forecast is reasonable.

242. The provision in the November 21, 2022 TURN-PG&E Energy Supply Stipulation agreeing to TURN's proposal that both upward and downward adjustments in the amortization of the LTSA milestone payments for natural gas plants should occur consistent with the actual performance of the combined cycle units is reasonable.

243. The provisions in the November 21, 2022 TURN-PG&E Energy Supply Stipulation agreeing to reduce the Humbolt Bay Generation Station replacement

engine emissions module costs by 16%, providing for a 50% reduction in emergent work capital expenditure forecast for costs tracked in MWC 2S and, removing the cost forecast for the Gateway Evaporative Cooling Project resulting in a reduced capital expenditures for costs tracked in MWC 2S of $3.405 million in 2023, $5.582 million in 2024, $5.714 million in 2025, and $1.735 million in 2026 and a total Fossil/Solar capital expenditure forecast of $6.100 million in 2023, $6.834 million in 2024, $6.879 million in 2025, and $2.925 million in 2026 are reasonable.

244. The provisions in the November 21, 2022 TURN-PG&E Energy Supply Stipulation providing for a Nuclear Operations capital expenditure forecast based on PG&E's forecast, in exchange for PG&E's agreement that it will only request the Commission authorized forecasts in this proceeding be recorded and recovered through the Diablo Canyon Retirement Balancing Account, are reasonable because TURN's concern is addressed that costs recorded to the Diablo Canyon Retirement Balancing Account are not currently subject to reasonableness review while the stipulation also presents sufficient capital for the safe and reliable operation of the Diablo Canyon Power Plant through expiration of the current operating licenses, resulting in a Nuclear Operations capital expenditure forecast of $11.0 million for 2023, $6.0 million for 2024, $1.0 million for 2025, and $0 million for 2026.

245. The provision in the November 21, 2022 TURN-PG&E Energy Supply Stipulation that provides for the continuation of the Diablo Canyon Retirement Balancing Account, and that capital expenditure of $11.0 million for 2023, $6.0 million for 2024, $1.0 million for 2025, and $0 million for 2026 be tracked in this account, and that any recorded capital costs exceeding $18 million for the combined years 2023 through 2026 will not be recorded to the Diablo Canyon

Retirement Balancing Account and PG&E will not seek recovery of any amount over $18 million in rates is reasonable.

246. PG&E's request to transfer the balance in the Nuclear Regulatory Commission Regulatory Balancing Account and close this balancing account was made based on a plan to discontinue operation of the Diablo Canyon Power Plant and now that PG&E may continue the Diablo Canyon Power Plant's operation this request is denied.

247. The provision in the November 21, 2022 TURN-PG&E Energy Supply Stipulation concerning the Hydro Licensing Balancing Account are reasonable that provide as follows: (1) PG&E will maintain the Hydro Licensing Balancing Account as a two-way balancing account, (2) PG&E will withdraw its proposal to include pre-2012 license condition settlement amounts in the Hydro Licensing Balancing Account, (3) PG&E agrees to provide refunds to customers if the actual combined capital and expense revenue requirements over each two-year period is less than authorized, (4) TURN agrees to not contest rate recovery by PG&E if combined capital and expense revenue requirements over each two-year period exceeds the authorized revenue by 20% or less, (5) parties agree to a Tier 3 Advice Letter for reasonableness review of combined capital and expense revenue requirements over each two-year period if they exceed authorized by more than 20%, and (6) PG&E withdraws its proposal for creation of the Helms Capacity Memorandum Account.

248. Regarding the Joint CCAs' framework proposal, it is reasonable to find that such a review would best take place in a broader proceeding in which other utilities and stakeholder positions may be considered and because consideration of the Joint CCAs' proposal in this proceeding would require a thorough

examination of the complexities involving the current vintaging framework and how costs are allocated as part of the PCIA.

249. The Joint CCAs' request for PG&E to provide specific information about its resources in future GRCs is reasonable, as this information will be helpful to our consideration of proposed changes to assets regardless of whether any broader framework is adopted. Accordingly PG&E is directed to include in its future GRC filings its position and any supporting evidence concerning (1) the details of any PG&E proposal for new asset life extensions, incremental capacity additions, or changed functions for any of its UOG assets and why it is undertaking these changes, (2) on whose behalf it is making these new investments, and (3) the appropriate vintaging treatment for each asset in light of this testimony along with any future GRC proposals.

250. The stipulation among PG&E, Cal Advocates, California Trout, Inc., Friends of The Eel River, and Trout Unlimited supporting a $48 million annual hydro decommissioning accrual for the record period of 2023-2026 is reasonable.

251. The November 21, 2022 TURN-PG&E Energy Supply Stipulation, the November 21, 2022 Cal Advocates-PG&E Energy Supply Stipulation, and the record demonstrate that TURN and Cal Advocates have a comprehensive understanding of the issues and facts concerning the stipulations and the capacity to engage in the stipulation process.

Section 6 Customer and Communications

Section 6.2. Regional Vice Presidents - Regionalization

252. PG&E's 2023 requested expense forecast for Regional Vice-Presidents (MWC OM) of $6.064 million is reasonable for the PG&E Regional Vice Presidents and their support staff because the forecast aligns with the cost estimates identified in D.22-06-028.

253. PG&E provided sufficient evidence to support its forecasted cost of the salaries for the Regional Vice President positions but concerns remain about excessive spending on staffing for regionalization.

Section 6.3 Customer Engagement

254. PG&E presents minimal information about the utility assets relied upon and other financial aspects of its Non-Tariffed Products and Services but states that its request of $49.851 million supports "PG&E's efforts to offer additional services [non-utility services] with existing assets [utility assets] to generate revenue, which reduces the costs of service in customer rates."

255. Further details regarding Non-Tariffed Products and Services, such as how PG&E implements a reduction "in cost of service in customer rates," are not provided.

256. Most of the information provided about profits and expense for Non-Tariffed Products and Services is found in PG&E's *Twenty-Fifth Periodic Report on Non-Tariffed Products and Services*, dated August 31, 2021, where PG&E shows costs and allocated profits for 2020 but a number of aspects of the program are unclear, for example, the amount of profits allocated to shareholders.

257. Regarding Non-Tariffed Products and Services, the amount of overall financial support provided by shareholders (who share in the profits) is particularly difficult to discern from the information provided by PG&E.

258. PG&E requests authorization to collect approximately $200 million from ratepayers to cover forecasted expenses for a program, Non-Tariffed Products and Services, that provides non-regulated services using utility assets and employees but provides few details on reliable revenue streams for ratepayers during the rate case period, how shareholders (and ratepayers) bear the risk of

potential losses, and how it implements a profit-sharing mechanism with shareholders.

259. Based on the information provided by PG&E regarding Non-Tariffed Products and Services, it is unclear how this program aligns with the Commission's Affiliate Transaction Rules.

260. PG&E has not supported the expense forecast for New Revenue Development Department Non-Tariffed Products & Services (MWC EL) consistent with the Commission's framework for evaluating these services in D.99-04-021 and D.11-05-018.

261. TURN's and Cal Advocates' use of PG&E's historical averages and 2020 actual expense to establish forecasted expense for New Revenue Development Department Non-Tariffed Products & Services (MWC EL) is more reasonable than PG&E's 2023 proposed expense of $49.851 million, and PG&E has not provided sufficient evidence to justify continued financial support of the program by ratepayers for this entire rate case period.

262. While short-term continuation of Non-Tariffed Products & Services, which is funded by ratepayers, is reasonable, longer-term continuation of this program, with funding by ratepayers, requires further information and consideration by the Commission.

263. Based on the absence of detail provided by PG&E for New Revenue Development Department Non-Tariffed Products & Services (MWC EL), it is reasonable to require an independent audit to fully explore the mechanics of PG&E's program.

264. An expense forecast should be adopted that supports shorter-term activities for New Revenue Development Department Non-Tariffed Products & Services (MWC EL) of two years, rather than the entire four-year rate case

period, which results in a forecast equaling $40 million in 2023 and an additional $40 million in 2024, the annual forecasted amount consistent with TURN's recommendation and with PG&E's recorded expense for 2020 is reasonable because such an expense forecast supports shorter-term activities for New Revenue Development Department Non-Tariffed Products & Services (MWC EL), as longer-term continuation of this program, with funding by ratepayers, requires further information and consideration by the Commission.

265. It is reasonable to adopt forecasted expense for 2025 and 2026 of $0 for New Revenue Development Department Non-Tariffed Products & Services (MWC EL) and PG&E may continue to offer these services under a shareholder-funded arrangement.

266. A capital forecast of $0 for Electric Vehicle Infrastructure Program and Internal Fleet Vehicle Program (MWC 28) for 2021-2026 is reasonable because PG&E has not provided such information in sufficient detail to support its forecast for these programs during this rate case period.

Section 6.4 Customer Services Offices

267. The 2023 expense forecast for Customer Service Offices (MWC IU) of $6.796 million is reasonable as it is consistent with the authorization granted in D.22-12-033 to permanently close Customer Service Offices and to transform Customer Service Offices.

268. PG&E's 2023 expense forecast for Customer Care (MWC OM) of $5.375 million includes the operating cost of officers except for those excluded by Rule 240.3b-7 of the Securities Exchange Act is consistent with Commission precedent and is reasonable.

269. Consistent with the authorization granted in D.22-12-033 to permanently close Customer Service Offices, TURN's recommendation of reducing the

PG&E's 2023 forecast of $17.991 million by $11.195 million is reasonable, as this reduced amount reflects the general level of operation granted to PG&E in D.22-12-033 for the closure and transformation of Customer Service Office.

Section 6.5 Compliance and Regulatory Strategy

270. The expense forecast of $5.375 million for Customer Care (MWC OM) is reasonable because it is consistent with past practice.

Section 6.6 Gas AMI Module Replacement Project

271. A forecast of $0 for replacing Advanced Metering Infrastructure modules tranche in MWC EZ, WMC HY, WMC IS and WMC JV (expense); and MWC 2F and WMC 74 (capital) is reasonable considering the benefits predicted by PG&E were small; PG&E failed to substantiate the claim that proactive replacement of Advanced Metering Infrastructure (AMI) modules is necessary to prevent additional costs; the need for further information to determine whether the cost of corrective maintenance is reasonable; the risk of additional costs based on the proactive approach outweighs the claimed benefits; the existing AMI modules continue to work effectively; not clear that the proposed investment is necessary or provides tangible customer benefits; and a disallowance may still be warranted.

Section 6.7 Customer Care Technology Projects

272. PG&E provide insufficient information to support its forecast for the Billing System Upgrade Project.

273. A forecast of $0 for the Billing System Upgrade Project, resulting in a 2023 expense forecast of $18.846 million for MWC JV and a 2023 capital expenditure forecast of $27.3 million for MWC 2F is reasonable.

Section 6.8 Uncontested Costs

274. PG&E's uncontested expense and capital expenditure forecasts set forth in PG&E Ex-06 and PG&E Ex-19, as revised, are reasonable.

Section 7 Shared Services and Information Technology

275. The stipulation regarding PG&E's enterprise data management and information technology 2023 forecasts for Operations and Maintenance for Baseline Operations and Management and Technology Investments in Solution Delivery and Operations, Fieldwork Management, Data Enablement, and Enterprise Resource Management Expense (MWC JV) totaling $378.375 million in expenses, and for PG&E's Technology Investments Portfolio, including Core Network Infrastructure and Operations, Capital (MWC 2F) totaling $259.9 million in capital expenditures is reasonable.

276. PG&E's 2023 expense forecast for Transitional Light Duty Payroll (WC Programs) of $5.610 million is based on the weighted average of the 2015-2019 recorded data, which gave the most weight to 2019 and gradually less weight to each prior year to forecast the 2020 payments and accounts for labor escalation during the 2021-2023 period and is reasonable.

277. The 2023 expense forecast for the Voluntary Plan and the Third-Party Disability Program Management of $2.052 million is based on the last recorded year before the expansion of the Voluntary Program and is reasonable.

278. The 2023 expense forecast for Disability Benefits of $30.869 million is based on a five-year average of costs that have been trending downward from 2016-2020 and is reasonable.

279. PG&E 's 2023 expense forecast for Wellness programs of $6.340 million is based on a five-year average of recorded costs and is reasonable.

280. PG&E's 2023 expense forecast for its Employee Assistance Program of $2.604 million is based on historical expenses, an estimated per employee per month increase, and estimated headcount adjustments and is reasonable.

281. The 2023 expense forecast for Mental Health Services of $13.683 million is based on three-year average and is reasonable.

282. The 2023 forecast for fuel expense resulting in a reduction in PG&E's Transportation Services (MWC AB) net expense forecast for 2023 of $3.459 million to $113.708 million is based on the 2017-2019 historical average of similar costs and emissions policies and is reasonable.

283. PG&E's 2023 forecast for vehicle expenses of $41.1 million is based on an increase in fire risk reduction initiatives, increased regulatory inspection requirements, vehicle safety campaigns, and is reasonably necessary to maintain vehicle availability.

284. PG&E's 2023 expense forecast for the Transportation Overhead Credit (MWC ZC) of $149.762 million is reasonably based on three years of recorded data (2017-2019) and that the "Fleet Overhead" credit is no longer applied to balancing account expense orders for 2020 GRC period-jurisdictional balancing accounts, as of 2020.

285. The 2023 capital forecast for Automotive Fleet (MWC 04) costs of $92.411 million is based on denying an unsupported increase in the capital forecast of $12.4 million. The amount of $92.411 million for this forecast is reasonable.

286. The 2023 forecast for Conference Center Program costs of $8.238 million is reasonably based on an average of the 2018-2019 data for similar costs.

287. A reduction in the 2023 forecast for the Facilities Management Program (MWC EP) forecast of $10.599 million is reasonably based on a four-year average

(2016-2019) of pre-pandemic costs adjusted for a varying level of costs associated with its San Francisco General Office.

288. PG&E's 2023 expense forecast for Line of Business Wildfire Mitigation Support (MWC IG) of $1.1 million is reasonably necessary to support wildfire mitigation work. Such costs are not in dispute and no longer so uncertain that that they must be tracked in the Fire Risk Mitigation Memorandum Account.

289. PG&E's 2023 forecast for the Building Overhead Credit of $62.171 is reasonably based on three years (2017-2019) of recorded data and future changes to how the overhead credit will be applied.

290. Denying inclusion of the price of purchasing PG&E's new corporate headquarters in Oakland of $892 million in PG&E's 2023 capital forecast for Real Estate Implementation (MWC 23) is consistent with D.21-08-027 and is reasonable.

291. Excluding $25 million from PG&E's 2023 capital forecast for the Aviation Operations Center is reasonable because PG&E has not substantiated any cost savings associated with the project, has not sufficiently demonstrated how the project funds will be used in 2023 and how the project will increase operational efficiencies, safety, and compliance compared to existing operations.

292. PG&E's 2023 forecast for security fencing (within the capital forecast for MWC 23) is reasonably based on the risk of physical attack and the need for increased security at PG&E's facilities.

293. PG&E's 2023 expense forecast for its Enterprise and Operational Risk Management (EORM) organization of $8.006 million is a reasonable cost of utility service that benefits PG&E's customers and that the increased cost for additional staff is necessary for EORM to provide service to PG&E's customers.

Section 8 Human Resources

294. PG&E presents an uncontested employee headcount forecast shows a significant 4% increase in 2021, then a forecasted decrease in 2025, and explains that the 2025 decrease to 27,141 is primarily attributed to the decommissioning of the Diablo Canyon Power Plant, offset by increases in Electric Operations. PG&E's actual employee headcount for 2020 is 25,600. PG&E's forecast employee headcount for 2021 is 27,312, 2022 is 27,492, 2023 is27,587, 2024 is 27,609, 2025 is 27,141, and 2026 is 27,227.

295. Regarding the uncontested 2023 expense forecasts and 2021, 2022, and 2023 requests for capital expenditures for Human Resources, as set forth in PG&E Ex-08 and PG&E's Opening Brief Appendix A, the Commission find those amounts reasonable.

Section 8.1 HR Solutions and Services

296. The five-year historical average presented by Cal Advocates for HR Solutions and Services A&G Salaries costs is reasonable because of the trend is decreasing but this methodology results in a forecast of $21.7 million if labor escalation is included, which is higher than both Cal Advocates' forecast of $18.54 million and PG&E's forecast of $20.464 million. As a result, the lower forecast which includes labor escalation of $20.464 million is reasonable.

297. Regarding HR Solutions and Services Outside Services Utility, PG&E's calculation is reasonable of $2.09 million based on a five-year average which accounts for escalation for Outside Services, an amount that is higher than the $1.92 million recommended by Cal Advocates but lower than PG&E's requested forecast of $2.231 million.

Section 8.2 HR Service Delivery and Inclusion

298. Consistent with PG&E's recommendation, it is reasonable to include labor escalation in the 2023 expense forecast for HR Service Delivery and Inclusion and, in addition, Cal Advocates recommendation to rely on the five-year historical trend is reasonable.

299. Regarding HR Service Delivery and Inclusion, because a five-year historical average 2016-2020 which accounts for labor escalation results in a 2023 expense forecast of $15.1 million, which is higher than PG&E's requested forecast of $14.447 million, the lower forecast for A&G Salaries for HR Service Delivery and Inclusion of $14.447 million is reasonable, as presented by PG&E.

300. Concerning Outside Services Utility (also referred to as contracts) within HR Service Delivery and Inclusion, Cal Advocates' recommendation is reasonable to use recent historical data of a four-year average (2017-2020) for Outside Services Utility because costs in 2016 were significantly higher than costs in following years, which suggests that 2016 costs were an outlier, and PG&E's recommendation to include labor escalation in this forecast is also reasonable.

301. Because a four-year average (2017-2020) forecast methodology for HR Service Delivery and Inclusion Outside Services Utility which also accounts for labor escalation for 2023 results in an Outside Services Utility forecast of $8.1 million, an amount higher than both PG&E's forecast of $5.462 million and Cal Advocates' forecast of $4.3 million, the lower forecast with includes labor escalation of $5.462 million should be adopted.

302. Regarding the companywide expense forecast of Workforce Transition-Severance within HR Service Delivery and Inclusion, Cal Advocates' forecast of $6.56 million is reasonable based on recent historical data of a four-year average (2017-2020) because, as stated by Cal Advocates, PG&E has

significant discretion when implementing layoffs to pay severance and to determine the amount of severance.

303. For the companywide expense Workforce Transition–Outplacement Assistance within HR Service Delivery and Inclusion, Cal Advocates' forecast of $78,000 is reasonable, which removes from the forecasting methodology the extreme fluctuation reflected in 2016-2017 and instead relies on the three-year trend presented in years 2018-2020.

304. For the companywide expense of Workforce Transition-Tuition Refund within HR Service Delivery and Inclusion, PG&E's methodology and forecast for 2023 expense of $3.9 million is reasonable, which accounts for forecasted participation in 2023 based on a five-year average multiplied by five-year average cost per participant because the years 2019-2020 were likely significantly lower due to bankruptcy, an anomalous event.

Section 8.3 Short Term Incentive Plan, Non-Qualified Retirement, Total Rewards and Labor Escalation

Section 8.3.1 Short-Term Incentive Plan

305. PG&E fails to carry its burden of proof that a 67.79% increase for this "at risk" incentive – which stands as a core value and basic job requirement - is reasonable, especially when customers face unprecedented rate increases and PG&E's Total Compensation Study concludes compensation is competitive at 8.9% of the market.

306. Disallowing ratepayer funding for the "financial goals metric of STIP is reasonable based on past Commission precedent.

Section 8.3.2 Non-Qualified Retirement Programs

307. Non-qualified retirement programs are set forth in PG&E Ex-08 Human Resources and PG&E presents a 2023 companywide expense forecast that

includes three components: (1) the Supplemental Executive Retirement Plans (SERP), (2) the Supplemental Retirement Savings Plan (SRSP), and (3) DC-ESRP.

308. Based on the record of this proceeding regarding the non-qualified retirement programs set forth in PG&E Ex-08, at this time when ratepayers face unprecedent rate increases, and TURN's compelling argument that these programs should be forecasted at $0 to reflect the absence of ratepayer benefit, it is reasonable to find PG&E has failed to carry its burden of proof to increases in these "at-risk" components of compensation over 2020 recorded adjusted of $2.832 million.

Section 8.3.3 Reward and Recognition Program

309. With regards to the Rewards and Recognition Program, it is reasonable to find that PG&E failed to carry its burden of proof that ratepayers should pay $18.6 million a year for purposes of employee recognition in cash payments, gift cards, and other non-monetary items (not specified) to PG&E employees at a time when customers are facing unpreceded rate increases.

310. PG&E employees deserve recognition for their work and for going beyond a supervisor's expectations, but it is unreasonable for that recognition to cost ratepayers $18.6 million in cash and gift cards annually under the Rewards and Recognition Program.

Section 8.3.4 Labor Escalation

311. PG&E's labor escalation proposal is reasonable as it is consistent with historical practice and is based, in part, on authorized escalations that cannot be avoided by PG&E due to labor agreements.

Section 8.4 Benefits Department and Employee Benefit

Section 8.4.1 Benefits Department

312. Cal Advocates' reliance on a five-year average of nominal dollars for Salaries within the Benefits Department does not account for labor escalation and the staffing cost increases needed to reflect hires and with those variables added to Cal Advocates' recommendation, the result is higher.

313. PG&E's expense forecast of $1.997 million is reasonable for Salaries within Benefits Department because the forecast accounts for staffing cost increases and labor escalation.

314. PG&E's 2023 expense forecast for Outside Services Utility of $224,000 within Benefits Department is reasonable because PG&E's cost increases are associated with additional legally required notices, escalation, and a five-year average of historical cost reflects the variability in costs over time.

Section 8.4.2 Health and Welfare Expense – Companywide Expense

315. PG&E's Health and Welfare companywide expense forecast of $536 million for PG&E and affiliates for 2023 is an increase of approximately 36% compared to 2020 recorded adjusted costs of $385 million.

316. Within the Health and Welfare companywide expense forecast, PG&E's Medical Program 2023 expense forecast presents a "dramatic" increase and PG&E fails to carry its burden of proving the reasonableness of its 2023 forecasted expense for Medical Program when stating that the Commission should not deviate from its longstanding practice of adopting medical costs forecasts based on actuarial analysis.

317. Regarding PG&E's Medical Program 2023 expense forecast, it is reasonable to find that the actuarial analysis of Mercer is unpersuasive as Mercer inadequately explains why PG&E's 2023 forecast does not reflect the trends

illustrated in the historical data and the variability one might expect in Medical Program when a modest change in headcount is forecasted.

318. PG&E's 2023 expense forecast for Medical Program is double the historical trend rate and PG&E does not adequately support this increase.

319. Cal Advocates' recommended 2023 forecast for Medical Program of $401.6 million, which is a $134.2 million (approximately 25%) reduction of PG&E's 2023 forecast of $536 million, is reasonable because it is based on a five-year average of historical expense.

320. Within the Health and Welfare companywide expense forecast Regarding Dental, it is reasonable to find that similar to Medical Program, PG&E fails to carry its burden of proof that a 2023 expense forecast of $37.780 million (2020 recorded adjusted is $26.7 million), which is a 40% increase over 2020 recorded adjusted, is reasonable.

321. Cal Advocates' recommendation for Dental, which is based on a five-year average (2016-2020) recorded costs for a 2023 expense forecast of $30.466 million (approximately $7 million less than PG&E's 2023 forecast) is reasonable.

Section 8.4.3 Post-Retirement Benefits - Companywide Expense

322. Regarding Retirement Savings Plan within Post-Retirement Benefits, a companywide expense, it is reasonable to find that PG&E fails to carry its burden of proof for its 2023 requested forecast of $145.702 million by not persuasively refuting Cal Advocates' arguments that PG&E's average increase of 5.45% from 2016 through 2020 is too high.

323. Cal Advocates' recommended 2023 expense forecast for Retirement Savings Plan within Post-Retirement Benefits, a companywide expense, is reasonable as it is based on the average increase of 5.45% applied to PG&E's

2020 recorded match of $119.450 million, which results in a 2023 forecast for Retirement Savings Plan of $140.072 million.

324. Regarding Retirement Excess Plan within Post-Retirement Benefits, a companywide expense, it is reasonable to find that PG&E did not carry its burden of proof for its requested 2023 expense forecast of $736,000 by not persuasively refuting Cal Advocates' lower forecast of $368,000 that relies on the Commission's recent decisions to limit the amount of this expense included in rates to 50% of the forecasted expense.

Section 8.4.4 Other Benefits – Companywide Expense

325. Regarding Relocation, which is a companywide expense under Other Benefits, it is reasonable to find that PG&E fails to carry its burden of proof based on its reliance on a four-year average (2016-2019) of costs per relocation for a 2023 expense forecasts of $7.073 million because a five-year average which includes 2020 presents a more reasonable forecast in this instance.

326. Cal Advocates' use of a four-year average (2017-2020) and a recommended 2023 expense forecast of $5.323 million, a reduction of $1.750 million, is not persuasive because the rationale for excluding one year, 2016 ($11.3 million), as a year of unexplained high relocation costs is not persuasive.

327. The experiences of 2020 during the COVID-19 pandemic changed modern work location trends and are relevant to the forecast for Other Benefits and, therefore, it is reasonable to include 2020 recorded expense when establishing a 2023 expense forecast for Relocation, which is a companywide expense under Other Benefits.

328. When establishing a 2023 expense forecast for Relocation, which is a companywide expense under Other Benefits, a five-year average would be the preferable outcome but such a forecast was not presented by any party and,

therefore, it is reasonable to adopt a compromise position by taking the average of the PG&E and the Cal Advocates forecast because the result of this average reflects expense during the five-year period (2016-2020), including the higher expense year in 2016 and, in addition, the more recent year of changing trends in 2020, which results in $6.2 million.

329. Regarding Commuter Transit Administration, a companywide expense under Other Benefits, PG&E's 2023 expense forecast based on a four-year average of recorded cost (2016-2019), which appropriately excludes the non-typical 2020 transit year due to COVID when most employees worked from home, is reasonable. Accordingly, the Commission adopts the 2023 expense forecast of $105,000 for the Commuter Transit Administration, a companywide expense within Other Benefits.

330. Regarding PG&E's 2023 expense forecast of $893,000 for Service Awards, a companywide expense within Other Benefits, it is reasonable to find that PG&E fails to carry its burden of proving that customers should pay for Service Awards, especially when customers face unprecedented rate increases and PG&E supports its request by stating that "The Company expresses appreciation for these employees with a recognition award at each five-year service anniversary and at retirement by inviting employees select an item, such as an engraved belt buckle, as a token of appreciation for continuous service and a signal to employees of their important service to the public.

331. For Service Awards, a companywide expense within Other Benefits, it is reasonable for PG&E to continue this program but not at ratepayer expense for this rate case period, 2023-2026, because PG&E has other programs for employee recognition with metrics more closely tied to customer interests.

Section 8.5 PG&E Academy Department

332. The September 16, 2022 Memorandum of Understanding between Engineers and Scientists of California Local 20 and PG&E, which resolve all contested issues pertaining to PG&E Academy, is uncontested and reasonable.

333. The request of Engineers and Scientists of California Local 20 and PG&E to enter PG&E Ex-66, September 16, 2022 Memorandum of Understanding between Engineers and Scientists of California Local 20 and PG&E, into the record of this proceeding is reasonable.

334. PG&E's 2023 expense forecast of $5.666 million for labor and $4.348 million for non-labor for PG&E Academy Gas Training within PG&E Academy is reasonable because the forecast reflects the use of labor escalation and additional needs.

335. PG&E's 2023 department expense forecast for PG&E Academy A&G Salaries of $6.049 million is reasonable because it incorporates labor escalation.

Section 8.6 Total Compensation Study

336. The Total Compensation Study Report is a report required by the Commission in D.95-12-005 which provides an analysis of PG&E's compensation structure.

337. Due to the passage of time since the Commission adopted the directive to prepare such reports in 1995, it is reasonable to require PG&E to submit a more holistic report to provide a more informative picture of compensation within PG&E and adopt refinements to the substance of these report to promote more effective evaluation of PG&E's compensation.

338. Accordingly, the Commission directs PG&E to include in all future total compensation reports provided pursuant to D.95-12-005 additional

compensation components, including the long-term incentive values and compensation related to long-term incentives.

Section 9 Administrative and General

339. PG&E, Cal Advocates and TURN resolved all the disputed areas of PG&E's Administrative and General (A&G) expense forecasts, with the exception of the wildfire liability insurance issues, by the November 1, 2022 A&G Stipulation. These parties settled their disputes regarding wildfire liability insurance on October 7, 2022, and the Commission adopted the settlement in D.23-01-005.

340. With respect to the November 1, 2022 Administrative and General (A&G) Stipulation, Cal Advocates and TURN each had a sound and thorough understanding of the application, issues, underlying assumptions, and record data, as expressed through their opening testimonies, discovery, rebuttal testimonies, and cross-examination at hearings, plus opening and reply briefs.

341. The November 1, 2022 Administrative and General (A&G) Stipulation contains agreement on all disputed issues which were a compromise of the parties' litigation positions, adopting the litigation position of Cal Advocates or TURN on some disputed issues, PG&E on others, and a compromise solution on other issues, reflecting a compromise of often strongly held litigation positions.

342. The November 1, 2022 Administrative and General Stipulation resolves the dispute regarding the Risk Transfer Balancing Account (RTBA) as follows: PG&E will use the RTBA to track the costs incurred to procure insurance coverage up to a target of $700 million. If annual incurred non-wildfire liability insurance costs are less than PG&E's forecast of $156 million, PG&E will return to ratepayers in the next annual RTBA true-up the difference between the amount collected and

the amount incurred. If annual incurred costs are above the forecast amount of $156 million, PG&E may seek recovery of those costs by application.

343. The stipulated use of the Risk Transfer Balancing Account (RTBA) in the November 1, 2022 Administrative and General Stipulation reasonably parallels the Commission's existing use of the RTBA and does not violate any law.

344. Because compromise can be necessary to resolve issues and reach agreement, the November 1, 2022 Administrative and General Stipulation is reasonable as an integrated agreement.

345. Stipulations can save the time and limited resources of the parties and the Commission in reaching reasonable results. The November 1, 2022 Administrative and General stipulation provides this benefit.

346. PG&E's uncontested 2023 expense and capital expenditure forecasts in PG&E Ex-09, and PG&E's Opening Brief, Appendix A at A-17 to A-18, A-25 and A-29 are reasonable. The parties' stipulated reduction of $312.244 million (approximately 28%) for a 2023 expense forecast of $798.704 million is reasonable.

Section 10 Result of Operation

Section 10.1 Depreciation

347. The UoP method of depreciation has not been adopted for any other utility, requires estimates many years into the future for the levels of demand and numbers of customers, and raises important questions and issues that are better addressed on an industry-wide basis in R.20-01-007, or a similar proceeding.

348. Straight-line depreciation is the appropriate method of depreciation for this general rate case consistent with utility industry and Commission practice.

349. A reduction in the service lives for a limited number of gas plant accounts is reasonable to reflect earlier retirement due to declining demand related to California's decarbonization goals and reduced use of natural gas.

350. For Electric Poles, Towers and Fixtures Account 364, depreciation survivor curve 47-R1.5 is reasonable because it corresponds with a composite remaining life of 38.47 years that aligns with both the first and third curves of pertinent recorded retirement data.

351. For Gas Mains Distribution Plant Account 376, depreciation survivor curve 60-R3 is reasonable because it corresponds with a remaining service life of 47.8 years that closely aligns with historical experience, and PG&E has not demonstrated that the entire gas mains asset class will be retired early at a consistent rate due to decarbonization goals.

352. For Gas Services Distribution Plant Account 380, depreciation survivor curve 55-R3 is reasonable because it corresponds with a service life of 41.02 years that is consistent with denying the replacement of gas services (tracked in MAT 50B) which may be repurposed to support electrification, and will align with the expected reduced use of this asset.

353. For the depreciation accounts in dispute other than Accounts 364, 376, and 380, the survivor curves recommended by TURN for the depreciation accrual account-curves shown in the Table herein are reasonably based on more recent experience bands and a gradual approach to changes in depreciation.

354. For TURN's estimates of net salvage percentages for the 13 accounts in dispute set forth in the Table herein, TURN's estimates of net salvage percentages are consistent with a gradual approach to changes in depreciation and historical data, and are reasonable.

355. PG&E's proposed depreciation and decommission rates for the Pleasant Creek gas storage facility are reasonable because PG&E has not sold, and continues to maintain, the Pleasant Creek gas storage facility.

356. PG&E's proposed refund of excess depreciation and accrued decommissioning costs totaling $103.874 million in 2023 for the Los Medanos Gas Storage Facility is reasonable because that facility is being retained.

Section 10.2 State and Federal Income Taxes

357. For the California Corporate Franchise Tax (CCFT) deduction amount in 2023, the 2022 CCFT amount of $109.081 million is on the record from PG&E's adopted 2022 attrition tables from the last GRCs consistent with the "flow-through" method adopted for all utilities in D.89-11-058 and is reasonable.

Section 10.3 Working Cash

358. PG&E's capital forecasted average customer deposits balance for 2023 of $81.5 million is based on 2020 recorded costs, reflects the impact of the Commission's 2020 restrictions on the collection of certain customer deposits in D.20-06-003, and is reasonable.

359. PG&E's forecast for bank lag of 0.58 days includes a high percentage (77.2%) of electronic payments, there is no compelling evidence that the percentage will increase, and PG&E's forecast is reasonable.

360. The revenue lag of 47.69 days from the 2020 GRC continues to be reasonable because the alternatives proposed by PG&E and TURN employ uncertainties with respect to use of 2020 data and use of recorded lags going back as far as 2014 and 2017 that are insufficient to justify a change.

361. A goods and services expense lag of 36.67 days is less than the 45 days lag that is a cash management best practice in the industry, is consistent with the lag

authorized by the Commission for other similarly situated utilities, and is reasonable.

362. TURN's recommended federal income tax lag days of 292 and state income tax lag days of 365 are reasonably based on PG&E's historical record of cash tax payments since 2010, its forecast for making tax payments for this GRC cycle, and consistent with Commission precedent.

Section 11 Post-Test Year Ratemaking: Years 2024, 2025, and 2026

363. Under the Commission's revised Rate Case Plan, this proceeding sets the revenue requirement for a four-year rate case cycle, while in the past the Commission has set the revenue requirement for three years.

364. Consistent with the Commission's recent decisions, including the August 19, 2021 decision on the test year 2021 general rate case for Southern California Edison Company, D.21-08-036, it is reasonable to treat expense and capital-related costs differently for purposes of post-test year ratemaking because expense and capital-related costs can affect revenue requirement differently, and adopts this practice in this proceeding.

365. The CPI-based recommendations presented in this proceeding do not provide a reasonable level of accuracy to project utility costs and, as a result, fail to provide PG&E a reasonable opportunity to recover costs in the post-test years.

366. It is reasonable the use of the energy-specific indexes in the S&P's IHS Markit's indexes (which is the same index that PG&E uses to escalate its expense from the recorded 2020 base year to the test year 2023) to adjust expense in the post-test years because the use of indexes is consistent with the Commission's historical practice for forecasting expense in the post-test years.

367. Energy-specific indexes provide a more accurate estimation of future costs for the procurement of goods and services in the utility industry than other indexes presented in this proceeding.

368. It is reasonable to find PG&E's recommendation persuasive to rely upon the energy utility-specific indexes to adjust expense in the post-test years because this will more likely provide PG&E an opportunity to earn its authorized rate of return during the post-test years, while keeping rates reasonable and affordable for ratepayers.

369. The energy utility-specific indexes proposed by PG&E is the S&P's IHS Markit's Utility Cost Information Service (and Power Planner for capital) and, as set forth at Section 13, herein, the Commission adopts the Second Quarter 2022 indexes, submitted by PG&E in its September 6, 2022 Update Testimony (PG&E Ex-33).

370. To promote efficient and fair consideration of a final decision by the Commission in general rate cases, it is reasonable here to establish post-test year capital-related costs based largely on a uniform adjustment mechanism and, in this proceeding, that uniform method adopted is the IHS Markit's Power Planner indexes.

371. For certain specific areas of PG&E's activities, it is reasonable to adjust post-test year capital adjustments through a budget-based approach.

372. It is reasonable for following cost categories related to capital expenditures be adjusted by specific budgets for attrition years, 2024-2026: StanPac (MAT 44A) in Section 3.12; Gas Transmission C&P Compressor Replacements and Retirements: Los Medanos Compressor Replacement (MAT 76X) in Section 3.5.3; Well Drilling (MAT 3L1) in Section 3.6.8; Well Reworks and Retrofits (MAT 3L3) in Section 3.6.9; Controls and Monitoring (MAT 3L5) in Section 3.6.12; New

Environmental Regulations Balancing Account (MWC 29) in Section 3.14.2; Natural Gas and Solar Capital Expenditures (MWC 2S, MWC 2T, MWC 3A, MWC 3B, MWC 05) in Section 5.4.1; Nuclear Operations Capital Expenditures (MWC 05, MWC 20) in Section 5.4.2; Hydroelectric Costs (MWC 05, MWC 11, MWC 12, MWC 2L, MWC 2M, MWC 2N, MWC 2P, MWC 3H) in PG&E Ex-05, Table 1-2; Corporate Real Estate (MWC 22, MWC 23) in PG&E Ex-07, Chapter 5; and Wildfire System Hardening (MAT 08W) in Section 4.3.

373. PG&E's uncontested proposal to adopt the Z-Factor mechanism for the attrition years, 2024, 2025, and 2026 is reasonable.

374. Because the purpose of a general rate case is to provide a fairly precise forecast of the test year, PG&E's proposal to apply the Z-Factor mechanism to the test year, 2023 is not reasonable.

375. The application of the Z-Factor mechanism is not simply ministerial and, therefore, it is reasonable to deny PG&E's request to rely on the advice letter process.

Section 12 General Reports – Escalation Rates and Other Topics

Section 12.1 Escalation Rates

376. Whereas PG&E had requested to use Second Quarter 2022 IHS Markit's Utility Cost Information Service and Power Planner indexes for purposes of adjusting the base year of 2020 to the test year of 2023, it is reasonable to grant 25% of the increase in IHS escalation rates associated with PG&E's September 6, 2022 update filing.

Section 12.2 Compliance with Prior Commission Decisions

377. PG&E request to "record $30 million" in capital towards the Inoperable and Hard to Operate Valves program" is reasonable as PG&E's request directs

funds towards a known safety concern in a timely manner during this rate case period (2023-2026).

378. It is reasonable to deny PG&E's request to "eliminate the associated report" on the basis that the report continues to serve the purpose of regulatory oversight of PG&E's use of funds directed in the Commission investigation in I.12-01-007, I.11-02-016, I.11-11-009.

379. It is reasonable to direct PG&E to commence work with the independent auditor to finalize the audit and file an advice letter to close this account.

Section 12.3 Balancing Accounts and Memorandum Accounts

380. The overreliance on memorandum and balancing accounts does not promote optimal utility ratemaking.

381. PG&E is requesting substantial and substantively significant revisions to numerous memorandum and balancing accounts in this proceeding, and it is reasonable to find that additional time is needed to fully review most of PG&E's proposals.

382. With respect to unopposed requests by PG&E to close balancing accounts and memorandum accounts, it is reasonable to grant these requests, as closing accounts will promote transparency and simplicity in regulation and the requests are unopposed, and it is reasonable to otherwise deny PG&E's requests to modify any continuing accounts.

Section 13 Update Testimony – PG&E Ex-33 September 6, 2022

383. Given that escalation rates are based on prior rates, it is important for the Commission to thoroughly review substantial increases in escalation rates and how they are applied to produce the most accurate and reliable forecast of test year expenses.

384. There was higher inflation in 2022 than expected when PG&E made its initial filing.

385. There is a range of rates in the record for PG&E's escalation rates.

386. In June 2021, the twelve-month percentage change in the U.S. consumer price index (or the annual average inflation rate) was 5.4 percent. One year later, in June 2022, the inflation rate rose to 9.1 percent.

387. It is reasonable to find that consideration of PG&E's Gas Transmission Accounting Method changes, as presented in the September 6, 2022 Update Testimony (PG&E Ex-33), falls outside the permitted and narrow scope of update testimony and PG&E's changes will not be reflected in the revenue requirement adopted in this proceeding.

388. Regarding applicability of gas transmission to the Tax Memorandum Account, it is reasonable to find that gas transmission was not included in the 2020 general rate case revenue requirement and therefore, the Tax Memorandum Account did not apply to GT&S revenue requirements prior to 2023.

Section 14 Memorandums of Understanding

389. The uncontested memorandums of understanding between PG&E and the following four parties are reasonable: the Small Business Utility Advocates, CforAT, National Diversity Coalition, and the Engineers and Scientists of California Local 20.

Section 15 Track 2 of Proceeding on Balancing Accounts and Memorandum Accounts and the January 6, 2023 Settlement

390. On July 22, 2022, PG&E removed several memorandum accounts from consideration in this proceeding, most of which were part of Track 2 of this proceeding, and requested a reduced amount of costs for consideration in Track 2.

391. PG&E's revised request in Track 2 requests cost recovery of approximately $208 million in expense and $129 million in capital expenditures, representing a total incremental revenue requirement of approximately $241 million, including $3.703 million in interest for 2015-2026, to be collected over a two-year period.

392. PG&E removed two memorandum accounts pertaining to wildfire mitigation activities, the Wildfire Mitigation Plan Memorandum Account and Fire Risk Mitigation Memorandum Account.

393. PG&E also removed the California Distributed Generation Statistics Website Memorandum Account from the proceeding.

394. On January 6, 2023, Cal Advocates and PG&E filed a joint motion for approval of a settlement resolving all issues in Track 2, the Joint Motion of Pacific Gas and Electric Company and The Public Advocates Office at the California Public Utilities Commission for Approval of a Settlement of Track 2 Issues (herein, the Joint Motion).

395. PG&E and Cal Advocates attached their settlement to the Joint Motion, as Attachment A, Settlement Agreement Between Pacific Gas and Electric Company and the Public Advocates Office at the California Public Utilities Commission on Track 2 Issues.

396. The provision in the January 6, 2023 Settlement between Cal Advocates and PG&E is reasonable that recommends that PG&E's total cost recovery for the accounts set forth in therein be $183.353 million for the recorded expense costs (a reduction of $25.600 million to PG&E's total request of $208.953 million) and $126.666 million of recorded capital costs (a reduction of $2.300 million to PG&E's total request of $128.966 million).

397. The January 6, 2023 Settlement does not include a calculation of the resulting impact on PG&E's requested revenue requirement or an explanation of

how the provisions of the Settlement impact PG&E's initial calculation of $241 million.

Section 16 Reduction to Revenue Requirement and Memorandum Accounts

398. PG&E estimates that the total 2023 through 2026 revenue requirement requests associated with capital costs in memorandum accounts presented in this proceeding is $950.612 million.

399. By including costs in its revenue requirement in this GRC that are also the subject of a separate reasonableness review application, PG&E is seeking recovery of these amounts in rates before it is appropriate to do so.

400. It is reasonable to implement the removal of these memorandum account amounts by subtracting the associated 2023 revenue requirement estimate of $249.958 million (subject to revision as final numbers are established) from the total 2023 revenue requirement.

401. It is reasonable to also apply a reduction to reflect the removal of the estimated revenue requirements associated with the costs recorded to memorandum accounts from the attrition years revenue requirements by subtracting $239.398 million for 2024, $235.115 million for 2025, and $226.141 million for 2026, subject to revision as final numbers are established.

Conclusions of Law

Section 3.3 Gas Mains and Services

1. The 2023 expense forecast for the Fitting Mitigation Program (MAT JQG) of $2.4 million is just and reasonable and should be adopted.

2. The 2023 expense forecast for the Cross Bore Program (MAT JQK) of $13.130 million is just and reasonable and should be adopted.

3. The 2023 capital forecast for the Steel Gas Pipeline Replacement Program (MAT 14A) of $99.200 million is just and reasonable and should be adopted.

4. The 2023 capital forecast for the Plastic Pipe Replacement Program (Capital MAT 14D) of $396.395 million is just and reasonable and should be adopted. The 2023 capital forecast for replacing 427 gas services per year of (MAT 50B) of $11.7155 million is just and reasonable and should be adopted.

Section 3.4 Gas Transmission Pipe

Section 3.4.1 In-Line Inspections (Capital & Expense Major Work Categories 75, 98, and HP)

5. The 2023 capital forecast for traditional ILI upgrades (MAT 98C) of $54.132 million should be adopted.

6. The 2023 expense forecasts for traditional ILI inspections (HPB) of $7.551 million and for non-traditional ILI inspections (HPR) of $3.360 million should be adopted.

7. The 2023 capital forecast for direct examination and repair (MAT 75P) is of $12.868 million should be adopted.

8. The 2023 expense forecast for direct examination and repair (MAT HPI) of $45.003 million should be adopted.

Section 3.4.2 Direct Assessment (MWC HP)

9. The 2023 expense forecast to complete external corrosion direct assessment indirect inspections (MAT HPC) on 268 miles of transmission pipelines in high consequence areas during the rate case period of $6.895 million should be adopted.

10. The 2023 expense forecast for external corrosion direct assessment direct examination (MAT HPN) of $34.393 million should be adopted.

11. The 2023 forecast for internal corrosion direct assessment (ICDA) engineering (MAT HPJ) of $0.671 million should be adopted.

12. The 2023 expense forecast for internal corrosion direct assessment (MAT HPO) of $11.829 million should be adopted.

13. The 2023 expense forecast for Stress Corrosion Cracking Direct Assessment (MAT HPK) engineering and surveys of $1.63 million should be adopted.

14. The 2023 expense forecast for Stress Corrosion Cracking Direct Assessment (MAT HPP) digs of $15.910 million should be adopted.

15. The 2023 expense forecast for the Transmission Integrity Management Program (MAT HPU) Direct Examination of $23.965 million should be adopted.

Section 3.4.3 Strength Testing (MWCs HP and 75)

16. The 2023 capital forecast for non-TIMP strength testing (MAT 75U) of $61.956 million in 2023 dollars should be adopted.

17. The 2023 capital forecast for non-TIMP pipeline replacement in lieu of strength (MAT 75R) testing $36.080 million should be adopted.

18. The 2023 expense forecast for non-TIMP pipeline replacement in lieu of strength testing (MAT JT6) of $10.622 million should be adopted.

19. The 2023 expense forecast of $19.917 million for TIMP strength testing (MAT HPF) should be adopted.

20. PG&E's 2023 expense forecast for pipe replacement in lieu of TIMP strength testing (MAT HPM) of $4.153 million should be adopted.

21. PG&E's 2023 capital forecast for capital pipe replacement in lieu of TIMP strength testing (MAT 75Q) of $17.899 million should be adopted.

Section 3.4.4 Vintage Pipe Replacement (Capital MWC 75E)

22. The 2023 capital forecast for Vintage Pipe Replacement (MWC 75E) of $3.7 million should be adopted.

Section 3.4.5 Shallow and Exposed Pipe Capital Cost (MAT 75K, 75M, 75T)

23. The 2023 capital forecast for Shallow and Exposed Pipe Program (MATs 75K, 75M, 75T) of $20.485 million should be adopted.

Section 3.4.6 Public Awareness Program (Expense MAT JT0)

24. The 2023 expense forecast for the Public Awareness Program (MAT JT0) of $3.063 million is reasonable.

Section 3.4.7 Balancing and Memorandum Accounts

25. The In-line Inspection Balancing Account should be eliminated by PG&E filing a Tier 1 Advice Letter requesting elimination of this account.

26. The In-line Inspection Memorandum Account should be continued for this rate case period.

27. The Internal Corrosion Direct Assessment Memorandum Account should be discontinued by PG&E filing a Tier 1 Advice Letter requesting elimination of this account.

28. The Gas Storage Balancing Account should be modified to allow recorded costs to be reviewed annually by Tier 2 Advice Letter.

Section 3.5 Gas Facilities

29. The 2023 expense forecast for the gas transmission Routine Compression & Processing (MAT JTY) of $8.263 million is just and reasonable and should be adopted.

30. The 2023 capital forecast for the Brentwood Terminal Rebuild Project (MAT 765) of $8.711 million is just and reasonable and should be adopted.

31. A forecast of zero dollars for the gas transmission and Gas Distribution Measurement and Control Station Overpressure Protection Enhancements Program (MATs FHQ, JTX, 50N and 76G) for this rate case period is reasonable and should be adopted.

32. A forecast of zero capital funding for the High-Pressure Regulator (HPR) Program (MWC 2K) for this rate case period is reasonable and should be adopted.

33. Adding $17.853 million from the High-Pressure Regulator Program for use in the Alternative Energy Program (Expense MAT AB#) is reasonable and should be adopted.

34. A 2023 forecast for the Tionesta Compressor Station Retirement Project (MAT 76X) of zero capital funding is reasonable and should be adopted.

35. PG&E's capital forecast for the Los Medanos K-1 compressor replacement project (MAT 76X) of $9.970 million, $10.219 million, $15.373 million, and $15.418 million in 2023, 2024, 2025, and 2026, respectively, is reasonable and should be adopted.

Section 3.6 Gas Storage

36. Due to changed circumstances, including the continued operation of the Diablo Canyon Power Plants, and changes in PG&E's gas demand forecast methodology, PG&E should resubmit its gas supply standard along with a revised updated peak-day supply standard analysis and forecast by application within 180 days of this decision.

37. As ordered in D.19-09-025, PG&E should file an application for review and approval of an improved curtailment process similar to those of other large energy utilities.

38. PG&E should maintain operation of the Los Medanos Gas Storage Facility.

39. PG&E's capital forecast for additional Well Drilling tracked in MAT 3L1 of $18.886 million in 2023, $45.884 in 2024, and $32.973 in 2025 is just and reasonable and should be adopted.

40. The capital forecast of Well Reworks (MAT 3L3) of $63.051 million for 2023, $56.891 million for 2024, $6.717 million for 2025, and $6.869 million for 2026 is reasonably based on the adopted number and unit cost of Well Reworks

41. .PG&E's capital forecast for Controls and Monitoring (MAT 3L5) of $1.365 million in 2023, $7.525 million in 2024, and zero funding for years 2025 and 2026 is reasonable and should be adopted.

42. An expense forecast for Well Reworks and Retrofits (MAT AH2) of $3.207 million in 2023, $3.283 million in 2024, $5.040 million in 2025, and $10.819 million in 2026 is reasonable and should be adopted.

43. For this GRC, the Commission adopts a forecast that authorizes six direct downhole casing re-inspections in 2026.

44. PG&E's 2026 expense forecast for Well Reworks and Retrofits (MAT AH2) for 2026 of $10.819 million is reasonable and should be adopted.

45. An expense forecast for Well Reworks and Retrofits (MAT AH2) of $3.207 million in 2023, $3.283 million in 2024, $5.040 million in 2025, and $10.819 million in 2026 is reasonably and should be adopted.

46. PG&E's Well Integrity Assessment Program (MAT AH1) expense forecast of $9.177 million in 2023, $9.640 million in 2024, $8.003 million in 2025, and $10.146 million in 2026 is reasonable and should be adopted.

Section 3.7 Gas Operations and Maintenance

47. The 2023 expense forecast for the Locate and Mark Program (MAT DFA) of $74.277 million should be adopted.

48. The 2023 forecast for Gas Distribution Standby Governance of $0.442 million should be adopted.

49. The 2023 forecast for Gas Transmission Standby Governance (MAT DFB) of $5.349 million should be adopted.

50. The 2023 expense forecast for the Meter Protection Program of $12.660 should be adopted.

51. The 2023 capital forecast for the Meter Protection Program (MAT 27A) of $5.332 million should be adopted.

Section 3.8 Gas Operations Corrosion Control

52. PG&E's 2023 expense forecast for Gas Main Atmospheric Corrosion Mitigation, which is work tracked in (MAT FHL), of $3.184 million should be adopted.

53. PG&E's 2023 expense forecast for Gas Distribution Atmospheric Corrosion Mitigation Services (MAT FHM) of $12.272 million should be adopted.

54. PG&E's capital forecasts for Gas Distribution Casing Mitigation over 100 feet (MAT 50D and 50Q) of $15.316 million in 2021, $19.530 million in 2022, and of $4.026 million in 2023 should be adopted.

55. PG&E's 2021 capital forecasts for Gas Transmission and Storage Corrosion Control of $1.342 million for the Internal Corrosion Program (Capital MAT 3K1), of $3.310 million for PG&E's AC Interference Program (Capital MAT 3K4), and of $7.411 million for PG&E's DC Interference Program (MAT 3K9) should be adopted.

Section 3.9 Gas Operations Leak Management

56. PG&E's 2023 expense forecast for Below Ground Distribution Main Leak Repair Program, which is work tracked in MAT FIG, of $33.715 million should be adopted.

57. The 2023 expense forecast for Meter Set Leak Repair work, which is work tracked in MAT FIS, of $9.278 should be adopted.

58. The 2023 capital forecast for the Below Ground Gas Distribution Service Replacement Program of $14.400 million should be adopted.

59. The 2023 expense forecast for Transmission Pipe Leak Repair (MAT JOP) of $9.231 million should be adopted.

Section 3.10 Gas Systems Operation

60. The 2023 expense forecast for Distribution Control Center Operations and Maintenance (MAT FGA) should be adopted.

61. The 2023 expense forecast for Gas Distribution Manual Field Operations (MAT FGB) of $0.957 million should be adopted.

62. The 2023 expense forecast for GT&S Operations (MAT CMA) of $15.360 million should be adopted.

63. The 2023 expense forecast for Electric Power for Compressor Fuel and Other Equipment (MAT CMB) of $27.500 million should be adopted.

64. The 2023 capital forecast for Supervisory Control and Data Acquisition (SCADA) Visibility Program – Gas Transmission Remote Terminal Units (Capital MAT 76M) of $2.778 million should be adopted.

65. A 2023 capital forecast of zero dollars for Supervisory Control and Data Acquisition (SCADA) Visibility Program – Gas Distribution Remote Terminal Units (Capital MAT 4AM) should be adopted.

66. The 2023 capital forecast for Gas Transmission Capacity for Load Growth (MAT 73A) of $6.028 million should be adopted.

Section 3.11 Gas Technology

67. The 2023 expense forecast for the Gas Research and Development and Deployment Program (MAT GZA) of $7.414 million should be adopted.

Section 3.12 Other Gas Operations Support

68. The uncontested 2023 expense forecast for the Alternative Energy Program portion of General Gas Operations Support (MAT AB#) of $2.6 million should be adopted.

69. The capital expenditures forecasts for the StanPac Transmission Pipeline (MAT 44A) of $2.887 million in 2023, $2.880 million in 2024, $15.245 million in 2025, and $15.736 million in 2026 should be adopted.

70. The 2023 expense forecasts for the StanPac Transmission Pipeline (MAT 34A) of $2.505 million should be adopted.

Section 3.13 New Business and Work at the Request of Others

71. The 2023 expense forecast for the Gas Distribution New Business Program (Capital MWC 29) of $7.923 million should be adopted.

72. The 2023 capital forecast for Gas Transmission Work at the Request Of Others Program (MAT 83A) of $16 million should be adopted.

Section 4 Electric Distribution

Section 4.1 Overview

73. Affordability and safety via a combination of risk reduction activities are the core of the of the Commission's mission, as stated by the Commission in 2015 and repeated in 2018, "… the ultimate balance the Commission must strike is between safety and reasonable rate levels, or as expressed in that same decision, 'between affordability and risk reductions.'"

74. This decision must determine whether PG&E has proven, by the preponderance of evidence, that its cost forecasts related to mitigating risk and other operational needs related to Electric Distribution are reasonable in light of the broader context of this proceeding.

Section 4.3 Wildfire System Hardening

Section 4.3.3 Risk Mitigation of Fire Ignition from Electric Overhead Infrastructure Section

75. Risk Spend Efficiency (RSE) values, which are a ratio of risk reduction and costs, should be considered, in addition to other factors, such as costs, feasibility

of construction, timeline for completion, and impact on telecommunications companies.

Section 4.3.4 Costs of Undergrounding as Compared to Covered Conductor

76. PG&E's uncontested 2023 expense forecast for System Hardening of $11.595 million is adopted.

77. It reasonable to develop a hybrid approach for undergrounding and covered conductor that balances elements of both PG&E's and TURN's system hardening proposals.

78. The "hybrid scenario" is just and reasonable and strikes a balance between risk reduction, feasibility, timeliness, and cost containment.

79. A unit cost of $1.261 million per mile in 2023, increasing over this rate case period to approximately $1.396 million per mile in 2026 for purposes of installation of covered conductor is adopted.

80. PG&E's 2023 estimated costs per mile for undergrounding of approximately $3.3 million per mile in 2023, decreasing over this rate case period to approximately $2.8 million in 2026 (four-year average cost of $2.97 million) is adopted.

81. PG&E's 1.25 conversion factor is adopted.

82. A "hybrid scenario" with 973 miles of undergrounding, 881 miles of covered conductor, and 146 miles of "covered conductor buffer" is adopted.

83. The forecasted capital cost of the "hybrid scenario" is $4.270 billion and is adopted.

Section 4.3.7 Accountability

84. Given the uncertainty associated with large scale undergrounding, the significance of this program as a risk reduction proposal, and the significant

ratepayer costs involved, it is prudent to require heightened tracking and reporting of costs and work to ensure accountability.

85. The requirement for PG&E to file a System Hardening Accountability Report Advice Letter is adopted pursuant to the requirements outlined in Section 4.3.7 of this Decision.

86. The requirement for spending for undergrounding and covered conductor mitigations to be tracked through the WMBA is adopted.

87. The Commission's ratification of an approved WMP does not authorize rate recovery; rather, the Commission considers the reasonableness of the costs of implementing the electrical corporation's WMP in its General Rate Case or an application for recovery of the cost of implementing the WMP as accounted in the memorandum account or otherwise.

88. An electrical corporation may pursue conditional approval of a 10-year undergrounding plan pursuant to Pub. Util. Code § 8388.5.

89. Given the Commission's concerns with the feasibility, cost, and risk reduction associated with PG&E's proposed undergrounding program and our determinations on the reasonableness of proposed forecasted costs made today, if PG&E seeks after-the-fact cost recovery for additional wildfire costs incurred during the rate case period covered by this GRC, the Commission should scrutinize additional costs per mile or additional miles of system hardening completed to ensure the resulting rates are just and reasonable.

90. Should PG&E implement its plan notwithstanding the Commission's determination that certain costs associated with the plan's costs are unreasonable, the Commission should scrutinize PG&E's justification for completing additional mileage.

Section 4.3.13 Discussion

91. The alternative proposed capital expenditures forecast of $4.270 billion associated with the "hybrid scenario," which combines elements of proposals from PG&E and TURN, is reasonable because it achieves a balance of risk reduction and cost containment.

92. The alternative proposed capital expenditures forecast of $4.270 billion associated with the "hybrid scenario," which combines elements of proposals from PG&E and TURN achieves a balance of risk reduction and cost containment and is adopted.

93. The Commission adopts a 2023-2026 cost forecast of $4.270 billion for capital expenditures for System Hardening, which consists of a forecast of $1.369 billion for overhead hardening and a forecast of $2.901 billion for undergrounding. The $1.369 billion of capital expenditures for overhead hardening are as follows: $323,827,628 (2023); $338,161,874 (2024); $348,165,802 (2025); and $358,469,922 (2026). The $2.901 billion of capital expenditures for undergrounding are as follows: $488,157,244 (2023); $630,577,194 (2024); $760,910,771 (2025); and $1,021,075,674 (2026).

Section 4.4 Other Wildfire Risk Mitigations

Section 4.4.1 Situational Awareness and Forecasting

94. The uncontested 2023 Situational Awareness and Forecasting expense forecast of $43.416 million (MWC AB) and capital expenditures forecast of $9.451 million in 2021, $9.375 million in 2022, and $4.601 million in 2023 (MWC 21) should be adopted.

Section 4.4.2 Public Safety Power Shutoff Operations

95. Because 2019 was an anomalous year for PG&E's use of PSPS and PG&E has taken steps to minimize the use of PSPS, a 2023 expense forecast of

$83.798 million for PSPS Operations (MWC AB) should be adopted that takes into consideration TURN's recommended reduction of $31 million to PG&E's 2023 expense forecast of $115.266 million.

96. Capital expenditures for PSPS Operations of $3.084 million in 2021, $3.237 million in 2022, and $262,000 in 2023 (MWC 21) should be adopted.

Section 4.4.3 Enhanced Automation and PSPS Impact Mitigation

97. Regarding the MAT 2AP Expulsion Fuse Replacement, PG&E's capital expenditure forecast, including work to replace non-exempt expulsion fuses, while PG&E continues to resolve potential defects, should be adopted and PG&E should be directed to provide an update on any amounts received from the manufacture regarding the potentially defective sensors.

98. PG&E's capital expenditure request of $12.369 million in 2021, $23.036 million in 2022, and $22.653 million in 2023 for MAT 49I Distribution Grid Sensors should be adopted based on its projected work and forecasting method while PG&E continues to resolve the potential produce defect issues and PG&E should be directed to provide an update on any amounts received from the manufacture regarding the potentially defective sensors.

Section 4.4.4 Community Wildfire Safety Program Project Management

99. PG&E's uncontested 2023 expense forecast of approximately $13.5 million regarding the Community Wildfire Safety Program Project Management Organization should be adopted. No capital expenditures are requested.

Section 4.4.5 Information Technology for Wildfire Mitigations

100. PG&E's 2023 uncontested expense forecast for Information Technology for Wildfire Mitigations of $35.700 million should be adopted.

101. PG&E's uncontested capital requests regarding Information Technology for Wildfire Mitigations of $35.700 million and capital expenditures of

$25.300 million in 2021, $25.300 million in 2022, and $25.300 million in 2023 should be adopted.

Section 4.4.6 Enhanced Powerline Safety Settings

102. TURN's recommendation to reduce PG&E's EPSS 2023 expense forecast to $87.049 million is adopted which is based on a convincing calculation of circuit miles and need for Additional Patrols.

103. A capital expenditure forecast of $0 for EPSS is adopted as PG&E states that capital is too uncertain to forecast presently.

104. It is reasonable for PG&E to continue to refine EPSS program implementation and pursue opportunities to use new technologies and efficiencies to narrowly tailor its EPSS program and improve restoration times.

Section 4.5 Emergency Preparedness and Response

105. The uncontested capital expenditure requests for Emergency Preparedness and Response of $2.109 million in 2021, $2.143 million for 2022, and $6.477 million for 2023 should be adopted.

Section 4.6 Electric Emergency Recovery

Section 4.6.1 Routine Emergency Capital (MWC 17) and Major Emergency Capital (MWC 95)

106. PG&E's capital expenditure forecast for MWC 17 Routine Emergency and MWC Major Emergency of $277.941 million for 2021, $339.418 million for 2022, and $360.523 million for 2023 should be adopted.

Section 4.6.2 Straight-Time Labor Costs and CEMA Events

107. Cal Advocates' recommendation to remove $20.079 million associated with PG&E's forecast for Catastrophic Events Memorandum Account (CEMA) straight-time labor costs from PG&E's Major Emergency Expense (MWC IF) forecast is reasonable and should be adopted.

108. After deducting the amount of $20.079 million, the Commission adopts an expense forecast for MWC IF Major Emergency Expense in 2023 of $42.709 million.

109. Removal of the forecasts for Catastrophic Events Memorandum Account straight-time labor should be adopted as follows: (1) 2023 expense forecast for MWC IG (Customer Care) is reduced by $144,000, expense forecast for MWC LX (Gas Operations) is reduced by $2.878 million, expense forecast for MWC LX (Generation) is reduced by $84,000, and (2) 2023 capital forecast for MWC 95 (Electric Distribution) is reduced by $16.375 million, capital forecast for MWC 3Q (Gas Operations) is reduced by $2.098 million, capital forecast for MWC 3Q (Generation) is reduced by $121,000.

Section 4.6.3 Catastrophic Event Straight Time Labor Balancing Account

110. PG&E's request for authorization to establish a new two-way balancing account, which PG&E refers to as the Catastrophic Event Straight Time Labor Balancing Account, should be denied.

Section 4.6.4 Documentation of CEMA Costs

111. Additional information should be required to support future requests by PG&E to remove Catastrophic Event Memorandum Account costs recorded to MWC IF Major Emergency Expense and MWC 95 Routine Emergency Capital for cost recovery elsewhere.

Section 4.7 Distribution System Operations

112. PG&E's 2023 uncontested expense forecast of $60.531 million for Distribution System Operations should be adopted.

Section 4.8 Field Metering

Section 4.8.1 Field Metering Revenue Collection

113. TURN's recommended 2023 expense forecast for MAT IU Field Metering Revenue Collection Program of $1.58 million which is based on historical data should be adopted.

Section 4.9 Vegetation Management

Section 4.9.1 Tree Mortality Program

114. PG&E's uncontested 2023 Tree Mortality Program forecast of $70.771 million should be adopted.

Section 4.9.2 Routine and Enhanced Vegetation Management

115. PG&E's 2023 forecast for Routine Vegetation Management (MWC HN) of approximately $1.31 billion for the MWC HN Routine Vegetation Management, including subaccounts, MAT IGJ Enhanced Vegetation Management and MAT IGI Tree Mortality Work should be adopted because it is based on 2020 recorded costs, which were significantly higher than prior recorded costs but likely reflective of future costs.

Section 4.10.1 Overhead Inspections

116. TURN's recommended 2023 forecast for MAT BFB Overhead Inspections of $49.148 million based on reducing PG&E's 2023 expense forecast by $9.659 million to account for the costs of Field Safety Reassessment pertaining to pole replacement that would not be required but for PG&E's work backlog should be adopted.

Section 4.11 Overhead and Underground Electric Distribution

Section 4.11.2 Unit Cost of Overhead and Underground Electrical Distribution Maintenance

117. For the purpose of evaluating PG&E's forecast for overhead and underground electrical distribution maintenance, PG&E has not persuasively established its proposed pace of work.

118. Given the uncertainty in the pace of work and unit cost of PG&E's electrical distribution maintenance work, it is reasonable to direct PG&E to record costs for overhead and underground electrical distribution work in a two-way balancing account.

Section 4.11.3 Overhead Equipment Replacement Expense Forecast (MWC KA)

119. TURN's 2023 expense forecast for MAT KAA Overhead Notification and Repair Program of $20.267 million, which is based on PG&E's historical data reflecting maintenance work performed without excessive costs, should be adopted.

Section 4.11.4.1 Overhead Notifications Program (MAT 2AA)

120. Cal Advocates' recommends a 2023 forecasted expense for the MAT 2AA Overhead Notifications Program of $133.0 million using a lower unit cost of $6,806 per notification and less overtime labor and fewer outside contractors should be adopted.

Section 4.11.4.2 Bird Safe Installations (MAT 2AB)

121. PG&E's capital expenditure request for MAT 2AB Bird Safe Installation and Replacement Program of $3.023 million for 2021, $3.841 million for 2022, and $3.474 million for 2023 based on 2019-2020 recorded costs should be adopted.

Section 4.11.4.3 Bird Safe Retrofits (MAT 2AC)

122. Based on PG&E's plans to increase the priority of corrective notices or tags for the work tracked in MAT 2AC Bird Safe Retrofits Program resulting in more work in a shorter time, PG&E's capital expenditures request for MAT 2AC Bird Safe Retrofits Program of $3.432 million in 2021, $3.626 million in 2022, and $3.615 million should be adopted.

Section 4.11.4.4 Idle Facilities Removal (MAT 2AF)

123. PG&E's capital expenditures forecast of $20.5 million in 2021, $2.732 million in 2022, and $2.726 million in 2023 for MAT 2AF Idle Facilities Removal Program should be adopted.

Section 4.11.4.5. Non-Wood Streetlights and Equipment with Access Issues (MAT 2AP)

124. PG&E's $1.0 million request for 2023 capital expenditures for the Non-Wood Streetlight Replacement Program is a $700,000 increase over 2020 recorded capital expenditures is not adopted.

125. Cal Advocates' recommended forecasts for 2023 capital expenditures of $800,000 for the Non-Wood Streetlight Replacement Program and $350,000 for the Equipment with Access Issues Program for a total forecast of $1.150 million is adopted because it is based on PG&E's average annual pace of spending from 2019-2021, including approximately $0 in 2020 for Non-Wood Streetlights.

Section 4.11.4.6 Ceramic Post Insulators (MAT 2AQ)

126. PG&E's capital expenditure request for the MAT 2AQ Ceramic Post Insulator Replacement Program of $3.960 million in 2021, $5.832 million in 2022, and $5.821 million in 2023 should be adopted because it reflects increased work in Tier 2 and 3 HFTDs, increased work in the MAT 2AR Non-Exempt Surge Arrester Replacement Program in 2021, and a plan to perform work independent of the surge arrestor replacement work in 2022.

Section 4.11.4.7 Field Automation System Overhead Replacement (MAT 2AS)

127. PG&E's capital expenditure request for MAT 2AS Field Automation System Overhead Capital Program of $639,000 for 2021, $831,000 for 2022, and $830,000 for 2023 should be adopted because it is consistent with PG&E's plans to increase maintenance of overhead electrical distribution maintenance.

Section 4.11.4.8 Non-Exempt Surge Arrester Replacement (MAT 2AR)

128. PG&E's Non-Exempt Surge Arrester Replacement Program (MAT 2AR) capital expenditure forecast of $88.859 million in 2021, $16.804 million in 2022, and $17.759 million in 2023 should be adopted as it is based on reducing the risk of electrical arcs, sparks, or other hot material during the operation of electrical lines even if in non-HFTDs.

Section 4.11.5 Underground Equipment Replacement

Section 4.11.5.1 Underground Notifications (MAT 2BA)

129. PG&E's request for capital expenditures for MAT 2BA Underground Notifications Program of $46.680 million in 2021, $46.391 million in 2022, and $47.807 million in 2023, which is based on additional work identified for regulatory compliance and an increase in the cost of work on larger enclosures containing high-voltage cables, should be adopted.

Section 4.11.5.2 Underground Critical Operating Equipment (MAT 2BD)

130. PG&E's forecast for the MAT 2BD Underground Critical Operating Equipment Program of $6.573 million in 2021, $6.354 million in 2022, and $6.926 million in 2023 should be adopted based on the 2018-2019 two-year average of the find rate plus additional units for open or pending jobs should be adopted.

Section 4.11.5.3 Street Light Program (MAT 2AH)

131. PG&E's capital expenditure request for MAT 2AH LED Streetlight Conversion Program of $1.028 million in 2021, $2.116 million in 2022, and $7.1 million in 2023 forecast should be adopted as it is based on an estimated increase in demand for conversions due to a decrease in the incremental facility charge.

Section 4.11.5.4 San Francisco Incandescent Streetlight Replacement (MAT 2AG)

132. For the San Francisco Incandescent Streetlight Replacement Program (MAT 2AG), PG&E did not plan to perform work in this program 2021-2022, will restart work in 2023, and plans to complete the work in 2024 and, as a result, a capital forecast of $0 in 2021, $0 in 2022, $2.5 million in 2023, and $2.6 million in 2024 should be adopted.

Section 4.12 Pole Asset Management

133. Regarding the uncontested forecasts for expense and capital expenditures for PG&E's Pole Asset Management Program should be adopted.

Section 4.12.1 Prior Pole Replacement

134. PG&E's enhancement of its inspection program was long overdue and the deferral of pole replacement work since at least 2003 has contributed to PG&E's current backlog of this work, which has developed over years, not suddenly.

Section 4.12.2 Pole Replacement Programs (MAT 07D, MAT 070, and MAT 07C)

135. Cal Advocates' 2023 capital expenditures request for the Pole Replacement Programs, including $337.48 million for MAT 07D, $7.18 million for MAT 07O and $3.02 million MAT 07C should be adopted as PG&E's requests are based on historical unit costs, a manageable future pace of work, and estimated future unit costs that are not excessive.

Section 4.12.3 Pole Replacement Forecasts for 2021 and 2022

136. PG&E's capital request includes costs for pole replacements for 2021 and 2022 that are included in the Wildfire Mitigation Plan Memorandum Account prior to a reasonableness review by the Commission should not be adopted.

Section 4.13 Overhead and Underground Asset Management and Reliability

137. The uncontested capital expenditures requests (MWC 08, MWC 49, and MWC 56) for PG&E's Overhead Asset Management and Underground Asset Management set forth at Appendix A of PG&E's Opening Brief at A-17 and A-25 are reasonable.

Section 4.13.1 Electric Distribution Overhead Asset Replacement (Capital MWC 08)

Section 4.13.1.1 Overhead Conductor Replacement Program (MAT 08J)

138. PG&E's capital expenditures request for its Overhead Conductor Replacement Program (MAT 08J) of $41.2 million in 2021, $32.7 million in 2022, and of $43.0 million in 2023 should be adopted based on performing work necessary to maintain safety and to ensure system reliability are reasonable.

Section 4.13.1.2 Overhead Switch Replacements (Capital MAT 08S)

139. Cal Advocates' recommended capital forecast for PG&E's Overhead Switch Replacement Program (MAT 08S) of $0.925 million of 2021, $0.949 million for 2022, and $0.3 million for 2023 should be adopted.

Section 4.13.2 Distribution Circuit Zone Reliability (Capital MWC 49)

Section 4.13.2.1 Overhead Fuses (MAT 49C)

140. PG&E's capital forecast for PG&E's Overhead Fuse Program (MAT 49C) of $0.882 million in 2021, $1.5 million in 2022, and $1.560 million in 2023 should be adopted.

Section 4.13.3 Electric Distribution Underground Asset Replacement

Section 4.13.3.1 Reliability Related Cable Replacement (MAT 56A)

141. PG&E's capital forecasts for the MAT 56A Reliability Related Cable Replacement program of $38.013 million in 2021, $39.556 million in 2022, and $36.976 million in 2023 are reasonable and should be adopted.

Section 4.13.3.2 Critical Operating Equipment Cable Replacement (MAT 56C)

142. PG&E's capital expenditure forecasts for MAT 56C Critical Operating Equipment Cable Replacement Program of $34.260 million in 2021, $33.030 million in 2022, and $36.002 million in 2023 should be adopted.

Section 4.13.3.3 Load Break Oil Rotary Switch Replacements (MAT 56S)

143. PG&E's capital expenditure request of $9.252 million for 2021, $9.493 million for 2022, and $8.1 million for MAT 56S LBOR Switch Replacement should be adopted.

Section 4.13.3.4 Temperature Alarm Devices (MAT 56T)

144. The capital forecast for MAT 56T Temperature Alarm Devices of $8.928 million in 2021, $3.075 million in 2022, and $8.5 million in 2023 should be adopted.

Section 4.14- 4.18 Electric Substations

145. PG&E's capital forecast for Install/Replace Network Assets (MWC 2C) and Electric Distribution UG Asset Replacements (MWC 56) of the $41.1 million for 2021, $44.0 million for 2022, and $44.4 million for 2023 to replace deteriorated or obsolete electric distribution network equipment should be adopted.

146. PG&E's capital forecast for its Circuit Breaker Replacement Program (MAT 48D) of $14.3 million for 2021, $31.3 million for 2022, and $28.6 million in 2023 should be adopted.

147. PG&E's capital expenditures forecast for the Switch Replacement Subprogram (MAT 48E) of $945,000 in 2021, $3.457 million in 2022, and $2.166 million in 2023 should be adopted.

148. PG&E's capital expenditures forecast for MAT 48X Animal Abatement of $4.533 million in 2021, $5.404 million in 2022, and $5.760 million for 2023 should be adopted.

149. PG&E's 2023 capital expenditure forecast for MAT 48C Battery Replacement of $200,0000 in 2021, $3 million in 2022, and $3.3 million in 2023 should be adopted.

150. PG&E's capital expenditures forecast for MAT 48L Line Work Support of $24.931 million in 2021, $6.027 million in 2022, and $9.105 million in 2023 should be adopted.

151. PG&E's capital expenditures for MWC 48 Replace Substation Equipment of $76.601 million for 2021, $96.588 million for 2022, and $96.331 million for 2023 should be adopted.

152. PG&E's 2023 capital forecasts for Distribution Transformer Replacements for MWC 54A and MWC 54L of $40.766 million in 2021, $27.970 million in 2022, and $21.243 million in 2023 should be adopted.

153. PG&E's 2023 capital forecast for the Fire Protection and Suppression subprogram (MAT 58A) of $3.3 million should be adopted.

154. PG&E's capital expenditures for MWC 58 Distribution Transformer Replacement of $5.980 million for 2021, $1.738 million for 2022, and $8.232 million for 2023 should be adopted.

155. PG&E's capital forecasts for the Electric Distribution Capacity Program (MWC 46 and MWC 06) of $286.313 million in 2021, $215.512 million in 2022, and $195.7 million in 2023 should be adopted.

156. PG&E's 2023 capital forecast for Residential Connects (MWC 16) of $261.565 million should be adopted.

157. PG&E's 2023 capital forecast for Non-Residential Connects (tracked within MWC 16) of $192.848 million should be adopted.

158. PG&E's capital forecast Distribution Transformer Purchases of $141.570 million in 2021, $151.725 million in 2022, and $169.068 million in 2023 should be adopted.

Section 4.19 Tariff 20A

159. TURN's recommendation of a five-year (2017-2021) average accounts for price changes over time and offers a more reasonable forecast than PG&E's as it adequately addresses PG&E's history of underspending relative to its forecast for Rule 20A conversion projects and, as a result, capital expenditures of $37.8 million for 2021, $28.2 million for 2022, and $29.2 million for 2023 for MWC 30 Electric Rule 20A should be adopted.

Section 4.20 Electric Distribution Data Management and Technology

160. The combined total Electric Distribution capital forecast for MWC 2F and MWC 21 of $17.696 million for 2021, $23.605 million for 2022, and $19.700 for 2023 is uncontested and should be adopted.

161. A reduction to PG&E's 2023 forecast for MWC GE Electric Distribution Mapping of $21.524 million by $3.915 million should be adopted for the Next Gen GIS project component of the GIS Asset Data Improvements.

162. The reduction, represented by the difference between PG&E's total 2023 expense request of $9.115 million for GIS Asset Data Improvements and the $5.2 million for the portions of the 2023 expense request for the four components that are unrelated to the historic Field Asset Inventory efforts, as described above, which results in a total 2023 expense forecast for MWC GE Electric

Distribution Mapping of $17.609 million: $0.391 million for Base Mapping, $6.765 million for GIS Technical Enhancements, $5.253 million for Data Management and Analytics, and $5.2 million for the adequately supported portions of GIS Asset Data Improvements should be adopted.

163. A reduced forecast for 2023 for Electric Distribution Mapping (MWC GE) of $17.609 million should be adopted.

164. To inform future improvements and visibility into PET analysis, a directive should be adopted for PG&E in future general rate cases to provide an explanation and workpaper justification, for each manual override performed on PET estimates, which at a minimum explain why the PET manual override more accurately estimates costs.

165. A reduction should be adopted in a total 2023 expense forecast for MWC GE Electric Distribution Mapping of $17.609 million: $0.391 million for Base Mapping, $6.765 million for GIS Technical Enhancements, $5.253 million for Data Management and Analytics, and $5.2 million for the adequately supported portions of GIS Asset Data Improvements.

166. An expense forecast for 2023 for Electric Distribution Mapping (MWC GE) of $17.609 million should be adopted.

167. PG&E's budget-based expense forecast anticipated for 2023 of $4.501 million should be adopted because it is persuasive and more appropriate, in this instance, than Cal Advocates historic three-year average.

168. PG&E's uncontested 2023 forecast for MWC JV Maintain IT Applications and Infrastructure in 2023 of $4.501 million should be adopted

Section 4.21 Integrated Grid Platform and Grid Modernization Plan

169. The 2023 expense forecast for MWC AT Electric Emerging Technology Program of $2.056 million should be adopted which reflects a reduction due to

the removal of $15.1 million for Technology Demonstration Project Work (EPIC funding).

170. The removal of the cost of ADMS 3 and DERMS from PG&E's request and Cal Advocates' recommended reduction of $27.735 million from PG&E's 2023 forecast for ADMS Release 3 and DERMS associated with their proposed removal should be adopted.

171. PG&E's capital expenditure forecast for ADMS and DERMS (MWC 63) of $81.882 million in 2021, $126.88 million in 2022, and $109.049 million in 2023 should be adopted.

Section 4.22 Electric Distribution Support

172. PG&E's uncontested Electric Distribution Support capital expenditures forecast for MWC 05 Tools and Equipment and MWC 21 Miscellaneous Capital is $18.340 million in 2021, $10.663 million in 2022, $8.394 million in 2023 should be adopted.

173. PG&E fails to explain how one year of data is not anomalous and, as a result, fails to justify an increase in MWC AB Miscellaneous, Electrical Distribution Support Expenses, compared to five years of data and, as a result, a lower 2023 forecast for MWC AB Miscellaneous Expenses, Electrical Distribution Support Expenses, of $23.167 million should be adopted.

Section 4.23 Community Rebuild Program – Town of Paradise

174. PG&E's requests pertaining to the rebuilding costs after the 2018 Camp Fire, as reflected in PG&E's Community Rebuild Program (including the Town of Paradise and surrounding area and the Butte Wildfire rebuild) and recorded in PG&E Ex-04 at WP Table 23-13 should not be adopted.

175. PG&E may seek recovery of the costs presented in PG&E Ex-04 at WP Table 23-13 in a CEMA application and, as a result,

176. An expense forecast of $0 and capital expenditures of $0 for all the expense and capital presented in this proceeding (2018-2026) PG&E Ex-04 at WP Table 23-13 should be adopted.

Section 4.24 Electric Distribution Ratemaking

177. Because PG&E presented insufficient evidence of "uncertainty" to continue the WMBA in its current format, as authorized in D.20-12-005, it is reasonable to continue the WMBA for this rate case period (2023-2026) as a one-way balancing account and with the 115% reasonableness threshold eliminated.

178. Because PG&E's vegetation management forecasts rely upon at least 4-5 years of data and PG&E has reached a higher level of sophistication, generally, regarding vegetation management within the context of climate change, the continuation of the VMBA to account for remaining external uncertainties should be adopted but a one-way balancing account is sufficient and a reasonableness review threshold is no longer appropriate

Section 5 Energy Supply

179. A 2023 expense forecast for the costs tracked in MWC CV Acquire and Manage Gas Supply within Energy Procurement Administrative of $2.445 million should be adopted.

180. The stipulated 2023 expense forecast for Hydro Operations of $171.9 million should be adopted.

181. The 2023 expense forecast for Natural Gas and Solar of $52.258 should be adopted.

182. The stipulated 2023 expense forecast for Nuclear Operations of $304.4 million should be adopted.

183. The provision in the November 21, 2022 TURN-PG&E Supply Stipulation adopting TURN's proposal that both upward and downward adjustments in the amortization of the LTSA milestone payments for natural gas plants should occur consistent with the actual performance of the combined cycle units should be adopted.

184. The provisions in the November 21, 2022 TURN-PG&E Supply Stipulation stipulating to a capital expenditure forecast for Natural Gas and Solar Generation including a MWC 2S forecast of $3.405 million in 2023, $5.582 million in 2024, $5.714 million in 2025, and $1.735 million in 2026 and a total Fossil/Solar capital expenditure forecast of $6.100 million in 2023, $6.834 million in 2024, $6.879 million in 2025, and $2.925 million in 2026, respectively should be adopted.

185. The provisions in the November 21, 2022 TURN-PG&E Supply Stipulation providing for Nuclear Operations capital expenditure forecast of $11.0 million for 2023, $6.0 million for 2024, $1.0 million for 2025, and $0 for 2026 should be adopted provided that PG&E only requests the Commission-authorized Nuclear Operations capital expenditure forecasts be recorded and recovered through the Diablo Canyon Retirement Balancing Account.

186. The provisions in the November 21, 2022 TURN-PG&E Supply Stipulation that PG&E may continue the Diablo Canyon Retirement Balancing Account, and that capital expenditure of $11.0 million for 2023, $6.0 million for 2024, $1.0 million for 2025, and $0 million for 2026 be tracked in this account should be adopted with the limitation that PG&E not record capital costs exceeding $18 million for the combined years 2023 through 2026 to the Diablo Canyon Retirement Balancing Account and PG&E not seek recovery of any amount over $18 million in rates.

187. Since PG&E may obtain authority to continue the Diablo Canyon Power Plant's operation in the future, PG&E's request to transfer the balance in the Nuclear Regulatory Commission Regulatory Balancing Account and close this balancing account should be denied.

188. The provisions in the November 21, 2022 TURN-PG&E Supply Stipulation PG&E and TURN concerning the Hydro Licensing Balancing Account that (1) PG&E will maintain the Hydro Licensing Balancing Account as a two-way balancing account, (2) PG&E will withdraw its proposal to include pre-2012 license condition settlement amounts in the Hydro Licensing Balancing Account, (3) PG&E agrees to provide refunds to customers if the actual combined capital and expense revenue requirements over each two-year period is less than authorized, (4) TURN agrees to not contest rate recovery by PG&E if combined capital and expense revenue requirements over each two-year period exceeds the authorized revenue by 20% or less, (5) parties agree to a Tier 3 Advice Letter for reasonableness review of combined capital and expense revenue requirements over each two-year period if they exceed authorized by more than 20%, and (6) PG&E withdraws its proposal for creation of the Helms Capacity Memorandum Account should be adopted.

189. The Joint CCAs' request for PG&E to provide specific information about its resources in future GRCs should be adopted, as this information will be helpful to our consideration of proposed changes to assets regardless of whether any broader framework and, accordingly, PG&E is directed to include in its future GRC filings its position and any supporting evidence concerning (1) the details of any PG&E proposal for new asset life extensions, incremental capacity additions, or changed functions for any of its UOG assets and why it is undertaking these changes, (2) on whose behalf it is making these new investments, and (3) the

appropriate vintaging treatment for each asset in light of this testimony along with any future GRC proposals.

190. The stipulation among PG&E, Cal Advocates, California Trout, Inc., Friends of The Eel River, and Trout Unlimited supporting a $48 million annual hydro decommissioning accrual for the record period of 2023-2026 should be adopted.

191. November 21, 2022 Cal Advocates-PG&E Energy Supply Stipulation, November 21, 2022 TURN-PG&E Energy Supply Stipulation, and the August 18, 2022 PG&E-Cal Advocates and California Trout, Inc., Friends of the Eel River, and Trout Unlimited should be adopted.

192. Unless otherwise provided for in the adopted stipulations, PG&E's uncontested 2023 expense and uncontested 2021, 2022, and 2023 capital expenditure requests as set forth in Appendix A to PG&E's Opening Brief at A-13 and A-24 should be adopted.

Section 6 Customer and Communications

Section 6.2. Regional Vice Presidents – Regionalization

193. PG&E's 2023 requested expense forecast for Regional Vice-Presidents (MWC OM) of $6.064 million should be adopted because the forecast aligns with the cost estimates identified in D.22-06-028

Section 6.3 Customer Engagement

194. An expense forecast should be adopted that supports shorter-term activities for New Revenue Development Department Non-Tariffed Products & Services (MWC EL) of two years, rather than the entire four-year rate case period, which results in a forecast equaling $40 million in 2023 and an additional $40 million in 2024, the annual forecasted amount consistent with TURN's recommendation and with PG&E's recorded expense for 2020.

195. While PG&E may continue to expand the services offered by New Revenue Development Department Non-Tariffed Products & Services (MWC EL) under a shareholder-funded arrangement, no forecast should be adopted for 2025 and 2026 based on the failure of PG&E to provide persuasive evidence that this program will generate profits on a longer-term basis.

196. The forecasted expense for 2025 and 2026 of $0 for New Revenue Development Department Non-Tariffed Products & Services (MWC EL) should be adopted because continuation of the program requires further information and consideration by the Commission.

197. Regarding New Revenue Development Department Non-Tariffed Products & Services (MWC EL), a requirement to retain an independent auditor, as a program expense, to perform an evaluation of this program should be adopted.

198. Regarding the transaction with SBA Communication Corporation in New Revenue Development Department Non-Tariffed Products & Services (MWC EL), it is reasonable for PG&E to provide the full amount of $135.5 million to ratepayers as revenues proportionally over the rate case period, 2023-2026 and, as a result, the $135.5 million will be reflected in PG&E's authorized 2023-2026 revenue requirements as an increase of $27.988 million in Other Operating Revenues to provide $33.875 million annually for 2023-2026.

199. A capital forecast of $0 for Electric Vehicle Infrastructure Program and Internal Fleet Vehicle Program (MWC 28) for 2021-2026 should be adopted because PG&E has not provided such information in sufficient detail to support its forecast for these programs during this rate case period.

Section 6.4 Customer Services Offices

200. PG&E's 2023 expense forecast for Customer Care (MWC OM) of $5.375 million should be adopted. consistent with Commission precedent, including the authorization granted in D.22-12-033 to permanently close Customer Service Offices and to transform Customer Service Offices.

201. PG&E's 2023 expense forecast for Customer Care (MWC OM) of $5.375 million is reasonable and should be adopted.

202. TURN's recommendation of reducing the PG&E's 2023 forecast for Customer Service Offices of $17.991 million by $11.195 million is reasonable as this reduction reflects the general level of operation granted to PG&E in D.22-12-033 for the closure and transformation of Customer Service Offices.

203. Regarding Customer Service Offices a $11.195 million reduction to PG&E's forecasts reflected in MWC DK, MWC EZ and MWC IU is reasonable and consistent with the authorization granted in D.22-12-033, and a 2023 expense forecast of $6.796 million should be adopted.

Section 6.5 Compliance and Regulatory Strategy

204. A 2023 expense forecast for Customer Care (MWC OM) of $5.375 million is consistent with past practice and should be adopted.

Section 6.6 Gas AMI Module Replacement Project

205. A forecast of $0 for replacing Advanced Metering Infrastructure modules tranche in MWC EZ, WMC HY, WMC IS and WMC JV (expense); and MWC 2F and WMC 74 (capital) is reasonable and should be adopted.

Section 6.7 Customer Care Technology Projects

206. PG&E's forecast for the Billing System Upgrade Project should not be adopted because PG&E did not provide sufficient information.

207. A forecast of $0 for the Billing System Upgrade Project, resulting in a 2023 expense forecast of $18.846 million for MWC JV and a 2023 capital expenditures forecast of $27.3 million for MWC 2F is reasonable and should be adopted.

Section 6.8 Uncontested Costs

208. PG&E's uncontested expense and capital expenditure forecasts set forth in PG&E Ex-06 and PG&E Ex-19, as revised, should be adopted

Section 7 Shared Services and Information Technology

209. The stipulation regarding PG&E's enterprise data management and information technology 2023 forecasts for Operations and Maintenance for Baseline Operations and Management and Technology Investments in Solution Delivery and Operations, Fieldwork Management, Data Enablement, and Enterprise Resource Management Expense (MWC JV) totaling $378.375 million in expenses should be adopted.

210. The stipulation regarding PG&E Technology Investments Portfolio, including Core Network Infrastructure and Operations, Capital (MWC 2F) totaling $259.9 million in capital expenditures should be adopted.

211. PG&E's 2023 expense forecast for Transitional Light Duty Payroll (WC Programs) of $5.610 million should be adopted.

212. The 2023 expense forecast for the Voluntary Plan and the Third-Party Disability Program Management of $2.052 million should be adopted.

213. The 2023 expense forecast for Disability Benefits of $30.869 million should be adopted.

214. PG&E 's 2023 expense forecast for Wellness programs of $6.340 million should be adopted.

215. PG&E's 2023 expense forecast for its Employee Assistance Program of $2.604 million should be adopted.

216. The 2023 expense forecast for Mental Health Services of $13.683 million should be adopted.

217. The 2023 forecast for fuel expense resulting in a reduction in PG&E's Transportation Services (MWC AB) net expense forecast for 2023 of $3.459 million to $113.708 million should be adopted.

218. PG&E's 2023 forecast for Vehicle Expense of $41.1 million should be adopted.

219. PG&E's 2023 expense forecast for the Transportation Overhead Credit (MWC ZC) of $149.762 million should be adopted.

220. The 2023 expense forecast for Automotive Fleet (capital MWC 04) activity of $92.411 million should be adopted.

221. PG&E's 2023 expense forecast for Materials (MWC AB) of $1.704 million should be adopted.

222. The 2023 forecast for Conference Center Program costs of $8.238 million should be adopted.

223. A reduction in the 2023 forecast for the Facilities Management Program (MWC EP) forecast of $10.599 million should be adopted.

224. PG&E's 2023 expense forecast for Line of Business Wildfire Mitigation Support (MWC IG) of $1.1 million should be adopted.

225. PG&E's 2023 forecast for the Building Overhead Credit of $62.171 million should be adopted.

226. Denying inclusion of the price of purchasing PG&E's new corporate headquarters in Oakland of $892 million in PG&E's 2023 capital forecast for Real Estate Implementation (MWC 23) should be adopted.

227. Excluding $25 million from PG&E's 2023 capital forecast for the Aviation Operations Center should be adopted.

228. PG&E's 2023 expense forecast for its Enterprise and Operational Risk Management (EORM) organization of $8.006 million should be adopted.

Section 8 Human Resources

229. PG&E forecast for employee headcount should be adopted.

230. The uncontested 2023 expense forecasts and uncontested 2021, 2022, and 2023 requests for capital expenditures for Human Resources, as set forth in PG&E Ex-08 and PG&E's Opening Brief Appendix A, should be adopted.

Section 8.1 HR Solutions and Services

231. A 2023 expense forecast for A&G Salaries for HR Solutions and Support of $20.464 million should be adopted because it includes labor escalation and is lower than a forecast based on Cal Advocates' methodology.

232. Regarding HR Solutions and Services Outside Services Utility, a 2023 expense forecast of $2.09 million should be adopted, which is based on a five-year average and accounts for escalation for Outside Services.

Section 8.2 HR Service Delivery and Inclusion

233. Consistent with PG&E's recommendation, labor escalation in the 2023 expense forecast for HR Service Delivery and Inclusion should be adopted and, in addition, Cal Advocates recommendation to rely on the five-year historical trend should be adopted.

234. Regarding HR Service Delivery and Inclusion, because a five-year historical average 2016-2020 which accounts for labor escalation results in a 2023 expense forecast of $15.1 million, which is higher than PG&E's requested forecast of $14.447 million, the lower forecast for A&G Salaries for HR Service Delivery and Inclusion of $14.447 million as presented by PG&E should be adopted.

235. Regarding Outside Services Utility within HR Service Delivery and Inclusion, a 2023 department expense forecast of $5.462 million should be adopted.

236. A 2023 expense forecast of $6.56 million for Workforce Transition-Severance of within companywide expense for HR Service Delivery and Inclusion should be adopted.

237. A 2023 expense forecast of $78,000 for Workforce Transition-Outplacement Assistance within companywide expense for HR Service Delivery and Inclusion should be adopted.

238. For the companywide expense of Workforce Transition-Tuition Refund within HR Service Delivery and Inclusion, the Commission adopts a 2023 expense forecast of $3.9 million.

Section 8.3 Short Term Incentive Plan, Non-Qualified Retirement, Total Rewards and Labor Escalation

Section 8.3.1 Short-Term Incentive Plan-Section

239. An expense forecast for 2023 of $87.212 million for STIP within Human Resources Compensation should be adopted after disallowing the Disallowing ratepayer funding for the "financial goals metric of STIP.

Section 8.3.2 Non-Qualified Retirement Programs

240. A SERP 2023 expense forecast of $2.832 million and SRSP/DC-ESRP 2023 expense forecast of $684,000 within Human Resources – Compensation should be adopted.

Section 8.3.3 Reward and Recognition Program

241. Cal Advocates' recommendation for a 2023 expense forecast of $0 for PG&E's Rewards and Recognition Programs within Human Resources should be adopted because PG&E's recognition of employee achievements can take other

forms, such as a promotion or a future raise, without ratepayers bearing an additional $18 million annually for cash and gift cards.

Section 8.3.4 Labor Escalation

242. PG&E's request to escalate labor expenses by 3.46%, including the General Wage Increases and market-based wage increases for 2021 and forecast through 2026, and reflected in "Table 4-2 2021-2026 Wage Increases" reproduced from PG&E Ex-08 should be adopted.

Section 8.4 Benefits Department and Employee Benefits

Section 8.4.1 Benefits Department

243. PG&E's 2023 expense forecast for Salaries of $1.997 million within Benefits Department should be adopted because the forecast accounts for staffing cost increases and labor escalation.

244. PG&E's 2023 expense forecast for Outside Services Utility of $224,000 within Benefits Department should be adopted.

Section 8.4.2 Health and Welfare Expense – Companywide Expense

245. Cal Advocates' recommendation for a 2023 expense forecast of $401.6 million for Medical Program, which is a $134.2 million (approximately 25%) reduction to PG&E's requested 2023 forecast of $536 million, should be adopted.

246. Cal Advocates' recommendation for a 2023 expense forecast of $30.466 million for Dental, which is approximately $7 million less than PG&E's requested 2023 forecast of $37.780 million, should be adopted.

Section 8.4.3 Post-Retirement Benefits - Companywide Expense

247. Cal Advocates' recommended 2023 expense forecast of $140.072 million for Retirement Savings Plan within Post-Retirement Benefits, which is a companywide expense, should be adopted.

248. Cal Advocates' recommended 2023 expense forecast of $368,000 for Retirement Excess Plan within Post-Retirement Benefits, which is a companywide expense, should be adopted.

Section 8.4.4 Other Benefits – Companywide Expense

249. A 2023 expense forecast of $6.2 million for Relocation, a companywide expense under Other Benefits should be adopted.

250. PG&E's 2023 expense forecast of $105,000 for the Commuter Transit Administration, a companywide expense within Other Benefits should be adopted because it is based on a four-year average of recorded costs (2016-2019), which appropriately excludes the non-typical 2020 transit year due to COVID when most employees worked from home.

251. A 2023 expense forecast of $0 for Service Awards within Other Benefits should be adopted because PG&E has other programs for employee recognition with metrics more closely tied to customer interests and ratepayer should not fund Service Awards for this rate case period, 2023-2026.

Section 8.5 PG&E Academy Department

252. The request of Engineers and Scientists of California Local 20 and PG&E to enter PG&E Ex-66, September 16, 2022 Memorandum of Understanding between Engineers and Scientists of California Local 20 and PG&E, into the record of this proceeding is granted.

253. The September 16, 2022 Memorandum of Understanding between Engineers and Scientists of California Local 20 and PG&E should be adopted.

254. PG&E's 2023 expense forecast of $5.666 million for labor and $4.348 million for non-labor for PG&E Academy Gas Training within PG&E Academy should be adopted.

255. PG&E's 2023 department expense forecast for PG&E Academy A&G Salaries of $6.049 million should be adopted.

Section 8.6 Total Compensation Study

256. Due to the passage of time since the Commission's directive in D.95-12-005 for PG&E to prepare total compensation report, additional compensation components for the report, including the long-term incentive values and compensation related to long-term incentives, should be adopted.

Section 9 Administrative and General

257. The November 1, 2022 Administrative and General Stipulation, including the stipulated forecasts, is reasonable in light of the record, consistent with the law, in the public interest, and should be adopted.

258. Since PG&E has already implemented the $400 million cost for self-insurance for third party wildfire claims via Advice Letter 6863-E-A, wildfire cost claims are variable, and there is a $1 billion target for the fund, wildfire liability self-insurance costs should be removed from the Results of Operations Model for this GRC.

Section 10 Result of Operation

Section 10.1 Depreciation

259. The straight-line depreciation method is reasonable and should be adopted.

260. For Electric Poles, Towers and Fixtures Account 364, depreciation survivor curve 47-R1.5 and a corresponding composite remaining life of 38.47 years is reasonable, and should be adopted.

261. For Gas Mains Distribution Plant Account 376, depreciation survivor curve 60-R3 and a remaining service life of 47.8 years is reasonable should be adopted.

262. For Gas Services Distribution Plant Account 380 depreciation survivor curve 55-R3 and a remaining service life of 41.02 years is reasonable and should be adopted.

263. For the depreciation accounts in dispute other than Accounts 364, 376, and 380, the survivor curves recommended by TURN for the depreciation accrual account-curves shown in Table, herein, are reasonable and should be adopted.

264. For TURN's estimates of net salvage percentages for the 13 accounts in dispute set forth in the Table, herein, TURN's estimates of net salvage percentages are reasonable and should be adopted.

265. PG&E's proposed depreciation and decommission rates for the Pleasant Creek gas storage facility are reasonable and should be adopted.

266. PG&E's proposal to refund excess depreciation and accrued decommissioning costs in 2023 for the Los Medanos gas storage facility is reasonable and should be adopted.

Section 10.2 Federal and State Income Taxes

267. For the California Corporate Franchise Tax (CCFT) deduction amount in 2023, the 2022 CCFT amount of $109.081 million is reasonable and should be adopted.

268. PG&E should file a Tier 1 advice letter providing the adopted CCFT amount for 2026.

Section 10.3 Working Cash

269. PG&E's capital forecasted average customer deposits balance for 2023 of $81.5 million is reasonable and should be adopted.

270. PG&E's forecast for bank lag of 0.58 days is reasonable and should be adopted.

271. A revenue lag of 47.69 days is reasonable and should be adopted.

272. A goods and services expense lag of 36.67 days is reasonable and should be adopted.

273. TURN's recommended federal income tax lag days of 292 and state income tax lag days of 365 are reasonable and should be adopted.

274. The uncontested forecasts for expenses and capital expenditures for the Results of Operations in PG&E Ex-10 are reasonable and should be adopted.

Section 11 Post-Test Year Ratemaking: Years 2024, 2025, and 2026

275. A bi-furcated methodology for determining expense and capital in the post-test years, 2024, 2025, and 2026 should be adopted consistent with past precedent and because expense and capital-related costs can affect revenue requirement differently.

276. The energy-specific indexes in the S&P's IHS Markit's indexes (which is the same index that PG&E uses to escalate its expense from the recorded 2020 base year to the test year 2023) to adjust expense in the post-test years should be adopted because the use of indexes is consistent with the Commission's historical practice for forecasting expense in the post-test years and energy-specific indexes provide a more accurate estimation of future costs for the procurement of goods and services in the utility industry than other indexes presented in this proceeding.

277. A uniform approach to adjusting expenses across all cost categories (labor is addressed separately) for the post-test years, as recommended by Cal Advocates, should be adopted, with the exception of Diablo Canyon, where the Commission adopts a bottoms-up approach, consistent with Senate Bill 846.

278. An energy utility-specific index as proposed by PG&E, the IHS Markit's Utility Cost Information Service, should be adopted to adjust all expense categories because it is the more accurate industry-specific forecast of costs in the

record of this proceeding and will more likely provide PG&E with funds needed to provide safe and reliable service to customers, as well as an opportunity to earn its authorized rate of return.

279. To promote efficient and fair consideration of a final decision by the Commission in general rate cases, the Commission has found it reasonable here to establish post-test year capital-related costs based largely on a uniform adjustment mechanism and, for this reason, a uniform adjustment mechanism for capital-related costs should be adopted.

280. Certain specific areas of PG&E's activities are more reasonably addressed through a budget-based approach to establish post-test year capital-related costs and should be adopted.

281. The following specific cost categories related to capital expenditures should adopt specific budgets for attrition years, 2024-2026: StanPac (MAT 44A) in Section 3.12; Gas Transmission C&P Compressor Replacements and Retirements: Los Medanos Compressor Replacement (MAT 76X) in Section 3.5.3; Well Drilling (MAT 3L1) in Section 3.6.8; Well Reworks and Retrofits (MAT 3L3) in Section 3.6.9; Controls and Monitoring (MAT 3L5) in Section 3.6.12; New Environmental Regulations Balancing Account (MWC 29) in Section 3.14.2; Natural Gas and Solar Capital Expenditures (MWC 2S, MWC 2T, MWC 3A, MWC 3B, MWC 05) in Section 5.4.1; and Nuclear Operations Capital Expenditures (MWC 05, MWC 20) in Section 5.4.2; Hydroelectric Costs (MWC 05, MWC 11, MWC 12, MWC 2L, MWC 2M, MWC 2N, MWC 2P, MWC 3H) in PG&E Ex-05, Table 1-2; Corporate Real Estate (MWC 22, MWC 23) in PG&E Ex-07, Chapter 5; and Wildfire System Hardening (MAT 08W) in Section 4.3.

282. PG&E's uncontested proposal to adopt the Z-Factor mechanism for the attrition years, 2024, 2025, and 2026 should be adopted.

283. Because the purpose of a general rate case is to provide a fairly precise forecast of the test year, PG&E's proposal to apply the Z-Factor mechanism to the test year, 2023 should not be adopted.

284. The application of the Z-Factor mechanism is not simply ministerial and, therefore, PG&E's request to rely on the advice letter process should not be adopted.

Section 12 General Reports – Escalation Rates and Other Topics

Section 12.1 Escalation Rates

285. It is reasonable to adopt 25% of the increase in IHS escalation rates associated with PG&E's September 6, 2022 update filing.

Section 12.2 Compliance with Prior Commission Decisions

286. PG&E request to "record $30 million" in capital towards the Inoperable and Hard to Operate Valves program" should be adopted as PG&E's request directs funds towards a known safety concern in a timely manner during this rate case period (2023-2026).

287. PG&E's request should be denied to "eliminate the associated report" on the basis that the report continues to serve the purpose of regulatory oversight of PG&E's use of funds directed in the Commission investigation in I.12-01-007, I.11-02-016, I.11-11-009.

288. PG&E should commence work with the independent auditor to finalize the audit and file an advice letter to close this account.

Section 12.3 Balancing Accounts and Memorandum Accounts

289. With respect to unopposed requests by PG&E to close balancing accounts and memorandum accounts, these requests should be granted, as closing accounts will promote transparency and simplicity in regulation and the requests

are unopposed, and otherwise PG&E's requests to modify any continuing accounts should be denied.

Section 13 Update Testimony – PG&E Ex-33 September 6, 2022

290. PG&E's requested increase due to inflation in this rate case deserves additional scrutiny commensurate with the requested increase.

291. PG&E has not met its burden of proof to demonstrate that the substantial increase in revenue requirement due to escalation included within its Update Testimony results in reasonable rates.

292. Pub. Util. Code Section 1822 requires the Commission to "verify, validate, and review the computer models of any electrical corporation that are used for the purpose of planning, operating, constructing, or maintaining the corporation's electrical transmission system, and that are the basis for testimony and exhibits in hearings and proceedings before the commission."

293. The Commission should not adopt the full increase requested in PG&E's September 6, 2022 update filing.

294. It is reasonable to adopt an amount within the range of options in the record in determining PG&E's 2023 test year revenue requirement.

295. The Commission takes official notice of the U.S. Bureau of Labor Statistics Chart of Consumer Price Index from January 2018 to June 2023, pursuant to Rule 13.9 of the Commission's Rules of Practice and Procedures and California Evidence Code Section 452.

296. Approving 25% of the increase in IHS escalation rates that PG&E requested associated with its update filing protects PG&E from the impact of high inflation while keeping rates at a reasonable level during a very uncertain economic time, due to numerous factors unique to the 2021-2022 time period. In

conjunction with all other increases approved in this decision, this result allows PG&E a fair opportunity to earn its authorized rate of return.

297. Consideration of PG&E's Gas Transmission Accounting Method changes, as presented in the September 6, 2022 Update Testimony (PG&E Ex-33), falls outside the permitted and narrow scope of update testimony and PG&E's changes should not be reflected in the revenue requirement adopted in this proceeding.

298. It is reasonable to find that gas transmission was not included in the 2020 general rate case revenue requirement and therefore, the Tax Memorandum Account should not apply to GT&S revenue requirements prior to 2023.

299. TURN's request should not be adopted to apply the 2021-2022 GT&S tax accounting changes.

Section 14 Memorandums of Understanding

300. PG&E has entered into memorandums of understanding (MOUs) with the following four parties: the Small Business Utility Advocates, CforAT, National Diversity Coalition, and the Engineers and Scientists of California Local 20. Some of these MOUs include spending commitments by PG&E, which are uncontested. These MOUs can be found as attachments to PG&E's Opening Brief. PG&E states these MOUs are reasonable and in the best interest of customers, and requests that the Commission approve them in this proceeding.

Section 15 Track 2 of Proceeding on Balancing Accounts and Memorandum Accounts and the January 6, 2023 Settlement

301. The Settlement resolves the disputed issues in a balanced way which reflects a compromise of the positions presented in the record of the proceeding, as litigated by PG&E and Cal Advocates. Cal Advocates, one of the settling parties, is statutorily charged to represent a broad spectrum of ratepayer interests and, as such, the Settlement should be found to be in the public interest.

302. January 6, 2023 Settlement between PG&E and Cal Advocates, as summarized above, the Commission finds the January 6, 2023 Settlement reasonable in light of the whole record, consistent with the law, and in the public interest.

303. The record in this proceeding and information presented in the Settlement establish that Cal Advocates and PG&E have the necessary understanding of the issues and facts, and the capacity to engage in the settlement process.

304. No terms within the settlement can bind the Commission in the future or violate existing law, and, as such, the Settlement should be found consistent with the law.

305. The January 6, 2023 Settlement should be adopted because PG&E and Cal Advocates resolved all issues set forth in Track 2.

306. The total cost recovery by for the Track 2 accounts of $183.353 million of recorded expense costs (a reduction of $25.600 million to PG&E's total request of $208.953 million) and $126.666 million of recorded capital costs (a reduction of $2.300 million to PG&E's total request of $128.966 million) should be adopted. In addition, PG&E and Cal Advocates agree on The following ratemaking matters, also agreed upon in the January 6, 2023 Settlement, should be adopted:

(1) The revenue requirement for recovery of the amounts agreed to in the Settlement shall be calculated consistent with the methodology described in PG&E's Prepared Testimony (PG&E Ex-80, Ch. 7) and that the gas revenue requirement associated with the amounts in Tables 3 and 4 will be recovered over two years as described in PG&E's Prepared Testimony (Exhibit PG&E-80, Ch. 7 at 7-13);

(2) The $272.2 million in costs PG&E incurred for projects completed in the Mobile Home Park (MHP) Pilot Program from January 1, 2018, through December 31, 2020, were reasonably incurred; and,

(3) The Greenhouse Gas Expense Memorandum Account GHGEMA shall be closed effective January 1, 2023.

307. PG&E is authorized to include in its revenue requirement the amounts for the individual balancing accounts and memorandum accounts set forth in the January 6, 2023 Settlement.

308. The January 6, 2023 Settlement should be adopted, unless modified herein, as resolving the issues presented in remaining matters presented in Track 2 of this proceeding.

Section 16 Final Authorized Revenue Requirement

309. The amounts PG&E records in memorandum accounts must be reviewed by the Commission for reasonableness before PG&E may recover them in rates through its authorized revenue requirement.

310. Pursuant to Pub. Util. Code Section 8386.4, PG&E may seek review of costs in its wildfire mitigation memorandum accounts in its GRC or in a separate application, but not both.

311. The revenue requirement for 2023 should reflect subtraction of $249.958 million; for 2024 subtraction of $239.398 million; for 2025 subtraction of $235.115 million; and for 2026 subtraction of $226.141 million, subject to revision as final numbers are established.

O R D E R

IT IS ORDERED that:

1. Application 21-06-021 is granted to the extent set forth in this Decision. Pacific Gas and Electric Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the 2023 test year base revenue requirement set forth in Appendix A, Appendix B, and Appendix C, effective January 1, 2023, and the revenue requirement for 2023 should reflect

subtraction of $249.958 million, subject to revision as final numbers are established.

2. Within 30 days from the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 Advice Letter to implement the revenue requirement and ratemaking adopted herein. The revenue requirement and revised tariff sheets will be effective January 1, 2024. The balance of the General Rate Case Revenue Requirement Memorandum Account shall be amortized in rates January 1, 2024, or as soon thereafter as may be effected, to December 31, 2026.

3. Pacific Gas and Electric Company (PG&E) is authorized to implement a Post-Test Year Ratemaking (PTYR) mechanism for both 2024-2026 as set forth herein, at Appendix A, Appendix B, and Appendix C. PG&E shall submit a Tier 2 Advice Letter by December 1, 2023 for the attrition year 2024, December 1, 2024 for the attrition year 2025, and December 1, 2025 for the attrition year 2026, and these Advice Letters shall rely on PG&E Ex-33 escalation, unless otherwise noted herein. The Advice Letters shall specify the revenue requirement adjustment for expense and capital-related costs and specifically set forth the manner PG&E calculated those revenue requirement adjustments. The attrition year revenue requirement shall be adjusted as follows: for 2024 subtraction of $239.398 million; for 2025 subtraction of $235.115 million; and for 2026 subtraction of $226.141 million, subject to revision as final numbers are established.

4. Pacific Gas and Electric Company shall continue to follow the directives in the Deferred Work Settlement and submit the related data in its 2027 general rate case, subject to the limitations of Public Utilities Code Section 8386.3, which

restricts the diversion of revenues authorized for certain wildfire mitigation activities.

Section 3.3 Gas Mains and Services

5. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 Advice Letter explaining how $225,000 in warranty settlement proceeds from the manufacturer of defective plastic fittings, discussed in Section 3.3, will be credited to ratepayers.

6. The amount Pacific Gas and Electric Company (PG&E) requested in this general rate case to replace gas service lines through MAT 50B that were not authorized shall be repurposed to incentivize the transition of home energy usage from gas to electric by adding such funds in the amount not authorized in MAT 50B to the Alternate Energy Program (MAT AB#). Within 60 days of the effective date of this decision, PG&E shall file a Tier 1 Advice Letter to create a two-way Alternative Energy Program Balancing Account to track the funds diverted from accounts for replacing gas assets that are added to the Alternative Energy Program (MAT AB#).

7. Within 60 days of the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 Advice Letter to establish a one-way balancing account for the Gas Distribution New Business Program (MWC 29).

Section 3.4 Gas Transmission Pipe

Section 3.4.7 Balancing and Memorandum Accounts

8. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 Advice Letter removing the In-line Inspection Balancing Account from its tariff.

9. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 Advice Letter removing the Internal Corrosion Direct Assessment Memorandum Account from its tariff.

10. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 Advice Letter to modify the Gas Storage Balancing Account to include the process of recorded costs to be reviewed annually by Tier 2 Advice Letter.

Section 3.5 Gas Facilities

11. Pacific Gas and Electric Company shall file one or more Tier 2 Advice Letters to fully document each phase of the Brentwood Terminal Rebuild project, including verification of the work completed and timelines for each phase, to obtain approval for additional funding for this project.

Section 3.6 Gas Storage

12. Within 180 days of the effective date of this decision, Pacific Gas and Electric Company shall submit an application for review and approval of its gas supply standard along with a revised updated peak-day supply standard analysis and forecast.

13. Within 180 days of the effective date of this decision, Pacific Gas and Electric Company shall file an application for review and approval of an improved curtailment process similar to those of other large energy utilities.

14. Pacific Gas and Electric Company shall file a Tier 2 Advice Letter annually to record Gas Storage Balancing Account costs after such costs are final for the year.

Section 3.11 Gas Technology

15. Pacific Gas and Electric Company (PG&E) shall not record any Gas Research Development and Deployment project expenses in a one-way balancing

account until an annual Tier 3 Advice Letter outlining its Gas Research Development and Deployment budget plan is filed and approved. PG&E shall submit its Tier 3 Advice Letting including its annual research plan by June 1, 2024 and must follow the guidance in this decision.

Section 3.12 Other Gas Operations

16. Within 60 days of the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 Advice Letter to establish a two-way balancing account for the Alternative Energy Program.

Section 3.13 New Business and Work at The Request of Others

17. Within 60 days of the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 Advice Letter to establish a one-way balancing account for the Gas Distribution New Business Program (MWC 29).

18. Within 180 days of the effective date of this decision, Pacific Gas and Electric Company (PG&E) shall host a meeting, in coordination with the Director of the Commission Energy Division to develop topics for annual reporting requirements and the timing for implementation to help inform the state's future efforts at coordinating customer electrification with opportunities to reduce gas system investments consistent with this decision. At least 10 days prior to the date of the meeting, PG&E shall provide notice via electronic mail of this workshop on the service list for the Long-Term Gas Planning proceeding, Rulemaking (R.) 20-01-007, and for the Building Decarbonization proceeding R.19-01-011.

Section 4.3.6 Pace of Undergrounding as Compared to Covered Conductor

19. In its next general rate case, or other application seeking funding for undergrounding, Pacific Gas and Electric Company (PG&E) shall provide the

cost per mile and risk reduction it achieved in all undergrounding projects in the previous two years.

Section 4.3.7 Accountability

20. Pacific Gas and Electric Company shall file an annual System Hardening Accountability Report Advice Letter with the Commission's Safety Policy Division every February 15th through the general rate case period, with the final report due February 15, 2027 pursuant to the requirements outlined in Section 4.3.7 of this Decision and serve it on the service list for this proceeding.

21. In each report on annual System Hardening Accountability, Pacific Gas and Electric Company shall demonstrate how much risk reduction it has achieved.

22. In its annual System Hardening Accountability Report, Pacific Gas and Electric Company shall explain its progress and the degree to which they meet or exceed reducing risk by 20% of the 2023 baseline risk amount.

23. Pacific Gas and Electric Company (PG&E) shall include the following information in the System Hardening Accountability Report on the previous year's activity with information for each completed covered conductor and undergrounding project: (1) Project Name, Location, and Tranche of each project, (2) circuit miles for each project, and (3) risk reduction achieved in each of the tranches. Attached to the report PG&E shall also include two specific spreadsheets for comparison in Excel and PDF format: (1) a "baseline" sheet for the mitigation portfolio as approved in the general rate case with projected annual risk reduction amounts, and (2) a "completed" sheet for the completed projects (i.e., update "Program Exposure" and "Program Cost" tabs in the completed project spreadsheet). Risk reduction will be measured by comparing the "completed" to "baseline" sheet. If the annual completed project risk

reduction is less than the total projected risk reduction, PG&E shall submit via Advice Letter to the Safety Policy Division a revised 2023 PG&E General Rate Case Wildfire Mitigation Spreadsheet which supports a plan on how PG&E will increase Wildfire Mitigation miles in the current year to eliminate the discrepancy in risk reduction.

24. Within 60 days of effective date of this decision, Pacific Gas and Electric Company (PG&E) shall file an initial Advice letter with Safety Policy Division establishing the methodology for the 'baseline system' spreadsheet for the System Hardening Accountability Report.

25. The Commission's Safety Policy Division (SPD) is delegated ministerial authority to adjust the requirements for this report, including but not limited to adjusting the baseline and baseline sheet and selecting the version of the Wildfire Distribution Risk Model, to advance the transparency and accuracy of the reporting. SPD may also require adjustments to the content and format of the report to ensure accuracy and consistency with the implementation of Senate Bill 884, should Pacific Gas and Electric Company choose to participate in the Senate Bill 884 program.

26. If the annual completed project risk reduction is less than the total projected risk reduction in the annual System Hardening Accountability Report, Pacific Gas and Electric Company (PG&E) shall submit via Advice Letter to the Safety Policy Division a revised 2023 PG&E General Rate Case Wildfire Mitigation Spreadsheet which supports a plan on how PG&E will increase Wildfire Mitigation miles in the current year to eliminate the discrepancy in risk reduction.

27. Spending for undergrounding and covered conductor mitigations shall be tracked through the WMBA. PG&E shall track unit cost for undergrounding and covered conductor mitigation programs annually.

28. Given the Commission's concerns with the feasibility, cost, and risk reduction associated with Pacific Gas and Electric Company's (PG&E's) proposed undergrounding program and our determinations on the reasonableness of proposed forecasted costs made today, if PG&E seeks after-the-fact cost recovery for additional wildfire costs incurred during the rate case period covered by this general rate case, the Commission will scrutinize additional costs per mile or additional miles of system hardening completed to ensure the resulting rates are just and reasonable.

29. Should Pacific Gas and Electric Company (PG&E) implement its plan notwithstanding the Commission's determination that certain costs associated with the plan's costs are unreasonable, the Commission may scrutinize PG&E's justification for completing additional mileage.

Section 4.4.3 Enhanced Automation and PSPS Impact Mitigation

30. Regarding the Expulsion Fuse Replacement Program, Pacific Gas and Electric Company (PG&E) shall credit the Wildfire Mitigation Balancing Account with any amounts received from the sensor manufacturer regarding the potentially defective sensors and is directed to discuss the status of this credit regarding the potentially defective sensors in the 2027 general rate case together with the status of resolving this matter with the sensor manufacturer. In addition, regarding the Expulsion Fuse Replacement Program, PG&E shall provide actual and forecasted unit costs information for 2021 through 2026 in its 2027 general rate case filing with an explanation for any dollar amount

differences between PG&E's forecasted unit cost in this proceeding and the actual 2021 costs.

31. Regarding the Distribution Grid Sensors, Pacific Gas and Electric Company (PG&E) shall credit the Wildfire Mitigation Balancing Account with any amounts received from the sensor manufacturer regarding the potentially defective sensors and is directed to discuss the status of this credit regarding the potentially defective sensors in the 2027 general rate case together with the status of resolving this matter with the sensor manufacturer. In addition, regarding the Distribution Grid Sensors, PG&E shall provide actual and forecasted unit costs information for 2021 through 2026 in its 2027 general rate case filing with an explanation for any dollar amount differences between PG&E's forecasted unit cost in this proceeding and the actual 2021 costs.

Section 4.6.4 Documentation of CEMA Costs

32. In future general rate cases and Catastrophic Event Memorandum Account (CEMA) proceedings, Pacific Gas and Electric Company (PG&E) shall provide the following information to support requests for recovery of costs related to the Major Emergency Balancing Account: (1) information on all costs attributed to CEMA events; (2) whether adjustments to any MWC to remove CEMA costs recorded in PG&E's Major Emergency Balancing Account include all costs attributed to CEMA events; (3) if adjustments above do not include all costs attributed to CEMA events, document the part that the adjustments to CEMA recorded costs include; and (4) if PG&E only removes authorized costs, PG&E must explain why costs above Commission authorized costs should be included in cost recovery related to the Major Emergency Balancing Account.

Section 4.11.2 Unit Cost of Overhead and Underground Electrical Distribution Maintenance

33. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company (PG&E) shall file a Tier 1 Advice Letter to create a two-way Overhead and Underground Electrical Distribution Maintenance Balancing Account to track the difference between the expenses for electric distribution maintenance in this decision and PG&E's recorded expenses for these activities. PG&E shall separately account for any additional costs associated with electrical distribution maintenance work in difficult-to- access or remote areas.

Section 4.13.1.1 Overhead Conductor Replacement Program (MAT 08J)

34. Pacific Gas and Electric Company shall in the 2027 general rate case provide additional information in testimony regarding outage levels and the useful lives of overhead conductors being replaced in the Overhead Conductor Replacement Program (MAT 08J) and the impact of this program on system reliability.

Section 4.13.3.1 Reliability Related Cable Replacement (MAT 56A)

35. Pacific Gas and Electric Company shall in the 2027 general rate case provide additional information in testimony regarding the Reliability Related Cable Replacement Program (MAT 56A), including: (1) data regarding outage levels, (2) the useful lives of the equipment being replaced, and (3) the unit cost for replacing it.

Section 4.13.3.2 Critical Operating Equipment Cable Replacement (MAT 56C)

36. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company (PG&E) shall file a Tier 1 Advice Letter to create a two-way balancing account for Critical Operating Equipment Cable Replacement (MAT 56C) to track the difference between the costs forecast for this program

authorized in this decision and PG&E's recorded expenses for these activities and shall include the following information regarding this cable replacement program, including (1) data regarding outage levels, (2) the useful lives of the equipment being replaced, and the unit cost for replacing it.

Section 4.13.3.3 Load Break Oil Rotary Switch Replacements (MAT 56S)

37. Pacific Gas and Electric Company shall in the 2027 general rate case provide additional information in testimony regarding the Load Break Oil Rotary Switch Replacement (LOBR) program, including the number of LOBR switches in operation, the service life, and years in service.

Section 4.23 Community Rebuild Program – Town of Paradise

38. Pacific Gas and Electric Company (PG&E) shall submit a table in its prepared testimony (rather than or in addition to its workpapers) in PG&E's next general rate case that reflects the same categories of information found in PG&E Ex-04 at WP Table 23-13 with updates to reflect the next rate case period to facilitate the Commission reviewing the Community Rebuild Program in its entirety. To facilitate transparency in costs and revenue requirement impact of wildfire Catastrophic Event Memorandum Account (CEMA)-related work, PG&E's Community Rebuild Program is a project that solely refers to the rebuild in the Town of Paradise and other wildfire-related "rebuild" projects shall be separately named, tracked, and presented in table format consistent with PG&E Ex-04 at WP Table 23-13, regardless of how PG&E internally accounts for these costs for purposes of general rate cases or records the costs in a CEMA account, in all future general rate cases.

Section 4.24 Electric Distribution Ratemaking

39. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 Advice Letter to modify the Wildfire

Mitigation Balancing Account consistent with this decision to a one-way balance account with no reasonableness review threshold.

40. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 Advice Letter to modify the Vegetation Management Balancing Account consistent with this decision to a one-way balancing account with no reasonableness review threshold.

Section 5 Energy Supply

41. Pacific Gas and Electric Company (PG&E) shall limit the costs recorded and recovered through the Diablo Canyon Retirement Balancing Account to the forecasted amount authorized in this proceeding for Nuclear Operations capital expenditure forecasts and this amount shall not exceed $18 million of authorized capital expenditures for the combined years 2023 through 2026 and, as agreed to by PG&E, any amounts exceeding $18 million shall not be recoverable in rates.

42. Pacific Gas and Electric Company shall file a Tier 3 Advice Letter seeking reasonableness review of costs if its combined capital and expense revenue requirements of for its Hydro Licensing Balancing Account over each two-year period of this rate case period (2023-2026) exceed the amount authorized by more than 20%.

43. Pacific Gas and Electric Company (PG&E) shall act consistent with the provisions of the November 21, 2022 Public Advocates at the California Public Utilities Commission-PG&E Energy Supply Stipulation, the November 21, 2022 TURN-PG&E Energy Supply Stipulation, and the August 18, 2022 PG&E-Cal Advocates and California Trout, Inc., Friends of the Eel River, and Trout Unlimited.

44. Pacific Gas and Electric Company (PG&E) shall provide specific information about its resources in future general rate cases (GRCs) is reasonable,

as this information will be helpful to our consideration of proposed changes to assets regardless of whether any broader framework is adopted. Accordingly PG&E is directed to include in all future GRC filings the following: (1) the details of any PG&E proposal for new asset life extensions, incremental capacity additions, or changed functions for any of its Utility Owned Generation assets and why it is undertaking these changes, (2) on whose behalf it is making these new investments, and (3) the appropriate vintaging treatment for each asset in light of this testimony along with any future GRC proposals.

Section 6 Customer and Communications

Section 6.2. Regional Vice Presidents - Regionalization

45. Pacific Gas and Electric Company (PG&E) shall provide the following in PG&E's 2027 general rate case: (1) additional recorded and forecasted cost information to be presented in the testimony for PG&E's regionalization activities associated with Regional Vice Presidents, their Executive Assistants, their Regional Support Staff, and the Regionalization Program Management Office for all Major Work Categories (and related subcategories of MAT Codes) including staffing salaries and benefits, information technology costs, real estate costs, and any other miscellaneous costs associated with regionalization; (2) the safety performance improvements that have occurred because of regionalization, including the performance improvements of individual enterprise-level safety metrics tracked at a regional level and the performance improvements of individual region-specific safety metrics; (3) comparison of the actual costs of regionalization implementation, including ongoing human resource costs, to PG&E's estimates of costs for regionalization implementation that PG&E presented in Application 20-06-011.

Section 6.3.1 Non-Tariffed Products and Services (MWC EL)

46. Pacific Gas and Electric Company (PG&E) shall retain all profits from New Revenue Development Department Non-Tariffed Products & Services (MWC EL) in an interest-bearing account and not distribute these profits to ratepayers or shareholders until authorized by the California Public Utilities Commission (Commission) after reimbursing ratepayers for the forecasted annual expense of $40 million. PG&E shall seek authorization from the Commission through a separate application proceeding before reinitiating Non-Tariffed Products & Services as a ratepayer-funded activity beyond the two years (2023 and 2024) authorized herein. PG&E shall file an application justifying continuation of this program on or before March 31, 2024, if PG&E seeks to continue the program with ratepayer expense funding, and such application shall, at a minimum, include information specified in this decision.

47. Pacific Gas and Electric Company (PG&E) shall retain an independent auditor, as a program expense, to perform an evaluation of New Revenue Development Department Non-Tariffed Products & Services (MWC EL), consistent with this decision. PG&E shall submit this audit in its 2027 general rate case and file and serve the audit in any application proceeding initiated by PG&E seeking authorization to continue its Non-Tariffed Products and Services program.

Section 6.4 Customer Services Offices

48. Pacific Gas and Electric Company to provide an explanation of the accuracy of the estimated $45.7 million in savings for Customer Service Offices during this rate case period (2023-2026) in the Tier 2 Advice Letter filing required by Decision 22-12-033.

Section 7 Shared Services and Information Technology

49. Pacific Gas and Electric Company (PG&E) shall record costs associated with moving PG&E's corporate headquarters to the building at 300 Lakeside Drive in Oakland, California in the General Office Sale Memorandum Account (electric) and the General Office Sale Memorandum Account (gas), including PG&E's exercise of its option to purchase or lease the Oakland property.

Section 8 Human Resources Section

50. Pacific Gas and Electric Company shall include in all future total compensation reports provided pursuant to Decision 95-12-005 additional compensation components, including the long-term incentive values and compensation related to long-term incentives.

Section 10 Result of Operation

51. Pacific Gas and Electric Company (PG&E) shall, if PG&E completes the sale of Pleasant Creek gas storage facility, file an application, within 60 days of the sale, pursuant to Pub. Util. Code Section 851 to address the calculation of gains or losses, and any refund or collection from customers, due to changes depreciation and decommissioning, resulting from the sale of this facility.

52. Pacific Gas and Electric Company (PG&E) shall, within 60 days of the effective date of this decision, file a Tier 2 Advice Letter to refund the excess depreciation and the accrued decommissioning costs as a result of PG&E's retention of the Los Medanos Gas Storage facility.

53. Pacific Gas and Electric Company shall, within 60 days of the effective date of this decision, file a Tier 1 Advice Letter providing the adopted California Corporate Franchise Tax (CCFT) amount for 2026 so that the prior-year adopted CCFT amount is readily available to be used as the deduction amount during the next general rate case.

Section 11 Post-Test Year Ratemaking: Years 2024, 2025, and 2026

54. Pacific Gas and Electric Company (PG&E) shall file a Post-Test Year adjustment by Tier 2 Advice Letter for attrition years 2024, 2025, and 2026 on or before December 1 for the upcoming attrition year. The attrition year revenue requirement and percentage adjustments for each attrition year shall be based on the authorized test year 2023 revenue requirement and the escalation rates in the Second Quarter 2022 IHS Markit's Utility Cost Information Service and Power Planner, the utility-specific indexes set forth in Update Testimony at PG&E Ex-33 together with the budget-based exceptions, to adjust its revenue requirements for the upcoming attrition years. PG&E shall file the relevant portion of those indexes and budget figures with the advice letters and specify the revenue requirement adjustment for expense and changes in capital-related costs.

Section 12 General Reports – Escalation Rates and Other Topics

55. Pacific Gas and Electric Company shall immediately commence work with the independent auditor to finalize the audit and file a Tier 2 Advice Letter to close the Shareholder-Funded Gas Transmission Safety Account (SFGTSA) on or before December 31, 2023.

Section 13 Update Testimony – PG&E Ex-33 September 6, 2022

56. PG&E shall implement a 2023 test year revenue requirement based upon only 25% of the increase in IHS escalation rates that it requested associated with the update filing for non-labor expense associated with its September 6, 2022 Update Testimony, relative to the escalation rates submitted with its 2023 GRC Application on June 30, 2021.

57. Application 21-06-021 remains open.

This order is effective today.

Dated ______________________, at Sacramento, California.

APPENDIX A – APPENDIX C