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. (U 39 M)	Application No. 21-06-021

PACIFIC GAS AND ELECTRIC COMPANY'S (U39M) REPLY BRIEF

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TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF AUTHORITIES

PAGE(S)

FEDERAL AUTHORITIES

Statutes and Regulations

CALIFORNIA AUTHORITIES

Statutes and Regulations

TABLE OF AUTHORITIES

PAGE(S)

Case Law

California Public Utilities Commission

Decisions

TABLE OF AUTHORITIES

PAGE(S)

TABLE OF AUTHORITIES

PAGE(S)

Proposed Decisions

Orders

Rulings

Resolutions

TABLE OF AUTHORITIES

PAGE(S)

Tariffs

Rules of Practice and Procedure

Miscellaneous

1. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Pursuant to California Public Utilities Commission (CPUC or Commission) Rule 13.12, and the *Assigned Commissioner's Scoping Memo and Ruling*[1] as modified by the *April 12, 2022 Email Ruling Addressing Pending Motions & Request to Modify Schedule and Adopting Revised Schedule*, Pacific Gas and Electric Company (PG&E) respectfully submits this Reply Brief.[2] This Reply Brief focuses on issues addressed by parties in their Opening Briefs submitted November 4, 2022.[3] Where parties' Opening Briefs repeat points made in their testimony but do not address PG&E's rebuttal testimony, we generally point to sections in our Opening Brief where parties' testimony was addressed. The fact that PG&E does not address a topic in PG&E's Opening Brief or this Reply Brief should not be taken as a concession or agreement in any respect to any issue. PG&E has left several issues from the Common Briefing Outline blank if there are no new issues to address.

1.1 Policy Overview

In this GRC, we are proposing plans necessary for our core mission of providing safe, reliable, affordable, clean energy to our customers. As our customers' local utility, we are

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1 *Assigned Commissioner's Scoping Memo and Ruling* (Oct. 1, 2021) (Scoping Memo),

2 PG&E's Reply Brief responds to the Opening Briefs of the following parties: AARP; AT&T, California Farm Bureau Federation (CFBF); California Trout Inc, Friends of the Eel River and Trout Unlimited; Central Valley Gas Storage, Lodi Gas Storage and Wild Goose Storage (jointly "Northern ISPs"); the Coalition of California Utility Employees; the Energy Producers and Users Coalition (EPUC); Comcast; Engineers and Scientists of California, Local 20 (ESC); Indicated Shippers; Joint Community Choice Aggregators (JCCA); Mussey Grade Road Alliance (MGRA); Northern California Generation Coalition (NCGC); Office of the Public Advocates at the California Public Utilities Commission (Cal Advocates); Peninsula Corridor Joint Power Board (Caltrain); Small Business Utility Advocates (SBUA); Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) (collectively "Joint Utilities"); Southern California Generation Coalition and the City of Palo Alto (SCGC/PA); The Utility Reform Network (TURN); Wild Goose Gas Storage and Lodi Gas Storage (Wild Goose and LGS); and Wild Tree Foundation.

3 All references to TURN's Opening Brief are to TURN's Amended Opening Brief submitted on November 8, 2022 and all references to Cal Advocates' Opening Brief are to Cal Advocates' Amended Opening Brief submitted November 10, 2022.

responsible for building a better future for them. To that end, the funding we seek will allow us to safely and reliably deliver for our hometowns, reduce the environmental impact of our operations, drive clean energy technologies, and, most importantly, protect our communities and make them more resilient to our ever-changing climate and increasing wildfire risk.

PG&E acknowledges that this proceeding raises important and challenging issues regarding safety, reliability, risk mitigation, and affordability. However, the Commission cannot and should not deviate from the core principles outlined by the California Legislature regarding utility service. First, the Legislature has determined that electric and gas service are vital to California residents and the California economy.[4] Second, the Legislature has found that "[s]afe and reliable electric and gas utility service is vital to public health, public safety, air quality, and reducing emissions of greenhouse gases."[5] Third, the Legislature has specifically focused on the critical need to minimize catastrophic wildfire risk.[6] Finally, the Legislature has emphasized the importance of affordable utility service, especially for low-income and vulnerable communities, and that utility rates be just and reasonable.[7] In developing our proposals in this proceeding, we kept in mind these Legislative directives and the need to provide reliable, safe, environmentally conscious, and affordable electric and gas service to our customers.

Below, we provide an overview of some of the key issues in this proceeding related to these principles, which are addressed in more detail in the sections that follow.

1.1.1 Safety Must Remain The Commission's Top Priority

Parties raise numerous challenges to the scope, pace, and timing of PG&E's work plans and forecasts, with customer affordability as a prominent theme. The Commission will need to address parties' arguments that PG&E is proposing to do too much to mitigate safety risks, and

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4 Pub. Util Code, § 854.2(a)(1).

5 Pub. Util Code, § 854.2(a)(2).

6 Pub. Util Code, § 8386(a).

7 Pub. Util Code, § 451.

that the proposed activities are too costly, making rates unaffordable in difficult financial times. Focused on reducing rates they perceive as too high, parties offer recommendations to reduce funding notwithstanding the impact their recommendations, if adopted, may have on safety outcomes. Indeed, several intervenors propose deep spending cuts in programs that are critical to maintaining public and employee safety. PG&E does not question that the intervenors have good intentions in wanting to keep customer rates as low as possible. PG&E shares that worthwhile goal. But it is also important to recognize that the parties recommending these deep cuts ultimately lack responsibility for the safety of the public and PG&E's extended workforce. That is a responsibility that PG&E alone carries. And with that responsibility at top of mind, PG&E's critical mission of delivering energy safely is an essential underpinning of PG&E's proposals. This core safety objective must not be swept aside solely for the sake of reducing costs. While the amount of the rate increase arising from this proceeding is an important issue that the Commission must consider as it reviews PG&E request, affordability should not come at the price of compromising safety. Putting safety first is the right thing to do.

If PG&E were to cut safety spending as the parties propose, there is little doubt that the safety of our gas and electric operations would be compromised. Several examples highlight this point.

Many of the parties, including Cal Advocates, TURN, AARP and MGRA propose deep reductions to PG&E's Community Wildfire Safety Program (CWSP), which is critical to address the risk of wildfire in our service area and has been successful in reducing ignitions that may lead to catastrophic wildfires. These proposed cuts include reductions to proven mitigation measures such as PG&E's undergrounding plans, PG&E's expulsion fuse and line sensor replacements, and Enhanced Powerline Safety Settings (EPSS) programs. These parties recommend deep cuts to other non-wildfire safety-related activities as well. TURN, for example, acknowledges the prudency of PG&E's electric system inspection programs, which are foundational to maintaining a safe system, but recommends a nearly 20 percent cut to PG&E's

overhead inspection forecast.[8] Cal Advocates also recommends a 70 percent reduction to PG&E's forecasts for: (1) overhead switch replacement program to minimize potential safety issues during switching operations and to improve reliability; and (2) load break (LBOR) switch replacement program to eliminate a safety risk for work crews.[9] Cal Advocates also recommends a nearly 30 percent reduction to PG&E's forecasts for non-wood streetlight replacements, notwithstanding that replacing non-wood poles, mitigates a public safety risk of catastrophic streetlight pole failures due to corrosion or damage.[10] AARP argues for an approximately 40 percent cut to PG&E's capital forecasts to prevent asset failures in downtown San Francisco and Oakland that could pose substantial safety risks to the public due to catastrophic failures such as manhole explosions/fire and safety risks.[11] Still more, Cal Advocates and TURN collectively recommend an approximately 33 percent reduction[12] to PG&E's forecast for pole replacements, which are necessary for PG&E to mitigate wildfire and other safety risks.

Other examples of proposed cuts in safety spending involve our gas distribution system. Cal Advocates, TURN, and AARP propose significant reductions to PG&E's plastic pipe replacement program over the GRC period from $500 million to $1.5 billion.[13] These

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8 TURN-09, p. 1, line 15, p. 29, lines 3-4.

9 Cal Advocates opposes PG&E's forecast for the Overhead Switches replacement program, which will address safety issues during operations. PG&E-17, p. 13-15; CALPA-06, p. 53, lines 13-18. Cal Advocates also opposes PG&E's forecast for the LBOR Switch replacement program, which will replace switches that pose a safety risk for work crews. PG&E-17, p. 13-21, lines 21-22, CALPA-06, p. 60, lines 4-17.

10 PG&E-04, WP 11-54.

11 AARP-01, p. 44, line 13 to p. 45, line 2; PG&E-17, p. 14-9, lines 9-12.

12 PG&E-17, p. 12-4, Table 12-2. Cal Advocates recommends a $31.8 million decrease to PG&E's pole replacement forecasts. CALPA-05, p. 16, Table 05-3. TURN recommends reductions exceeding $75 million to PG&E's pole replacement forecasts. TURN-09, p. 50, lines 9-14.

13 TURN Amended Opening Brief, pp 118-120; AARP Opening Brief, pp. 17-20; Cal Advocates Opening Brief, pp. 54-56.

reductions are proposed despite record evidence that plastic pipe failures have resulted in explosions and fatalities due to cracking and failure.[14] These reductions contradict recommendations of the Office of the Safety Advocate, now part of the Safety and Enforcement Division, in the 2020 GRC to increase the rate of plastic pipe replacement.[15] TURN also recommends significantly reducing funding for PG&E's In-Line Inspection (ILI) upgrade program designed to facilitate inspections of gas transmission pipelines;[16] and reducing by two thirds the number of "cross bore" inspections that detect hazardous service installations through sewer lines.[17] Finally, TURN recommends that the Commission eliminate entirely a number of critical gas safety programs including replacement of vintage transmission pipe;[18] mitigation of shallow and exposed transmision pipe;[19] PG&E's Over Pressure Protection (OPP) program aimed at installing valves at regulator stations to prevent pressure spikes from migrating downstream to end users;[20] PG&E's SCADA visibility program designed to improve visibility into system conditions to allow detection of abnormal operating conditions and prevention of loss of containment incidents;[21] and PG&E's High Pressure Regulator (HPR) program for replacement of aging and obsolete regulator stations.[22]

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14 CUE Opening Brief, p. 7.

15 PG&E-03, p. 4-27, line 25 to p. 4-29, line 8.

16 TURN-04, p. 11, lines 5-21.

17 TURN-06, p. 35, line 5 to p. 38, line 8.

18 TURN-04, p. 52, lines 17-18.

19 TURN-02, p. 108, lines 5-7.

20 Gas Distribution Over Pressure Protection program (TURN-02, p. 113, lines 13-15); Gas Transmission Over Pressure Protection program (TURN-02, p. 116, lines 7-9).

21 Gas Distribution Regulator Station Monitoring (SCADA) program (TURN-02, p. 124, lines 5-7); and Gas Transmission SCADA Visibility program (TURN-02, p.127, lines 1-3).

22 TURN-02, p. 119, lines 1-3.

The Commission should consider all evidence regarding these assets' safety risks when considering intervenor proposals to slash funding for these critical safety programs.

1.1.2 PG&E's Critical Public Safety Improvements Will Continue With Appropriate Funding

The same parties who advocate for less safety spending allege that PG&E's spending on safety and risk mitigation measures has not improved safety.[23] This is incorrect. Safety has demonstratively improved in PG&E's service area in recent years due to our significant investment in our electric and gas infrastructure.

For example, in our Community Wildfire Safety Program, we are on track to underground at least 175 miles of distribution electric lines in and near high fire-threat areas this year, more than doubling the mileage that we completed in 2021. We continue to make progress in reducing wildfire risk as seen through ignition counts, where we have seen a 34% reduction compared to 2021 and to the 3-year average in our CPUC-reportable ignitions as well as reductions in fire size. The primary driver for ignition and fire size reduction is currently our EPSS program which demonstrates positive and measurable impacts.

Our gas operations are safer due to recent investments in both pipe replacements and inspections. As discussed in PG&E-3, in 2019 we added 710 miles of transmission pipe capable of being inspected with in-line inspection tools, strength-tested over 154.1 miles of transmission pipeline, and replaced 6.49 miles of transmission pipeline. In 2020, we replaced more than 131 miles of distribution main pipeline and 2,567 gas services.

For our generation assets, in 2022 PG&E achieved ISO 55000 certification for its entire power generation portfolio, including dams, hydro powerhouses, civil infrastructure, fossil, solar, battery storage, physical data and data assets. ISO 55000 certification demonstrates that Power Generation manages its assets according to an internationally recognized management system that achieves the highest possible public safety outcomes while delivering on cost and reliable

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23 See e.g. AARP Opening Brief, pp. 3-4; TURN Amended Opening Brief, p. 531.

performance commitments. Effective asset management systems improve safety by helping organizations achieve their purpose, mission, and strategic goals by ensuring decisionmakers and other stakeholders have access and information needed for proactive risk and performance decisions.

These types of safety and other improvements will continue with adequate funding during the 2023 GRC period.

1.1.3 The Commission Should Deny Party Proposals To Solely Consider Risk Spend Efficiency Results To Decide Whether Critical Risk Mitigation Work Should Be Funded

As a corollary to their arguments that safety should not be prioritized over affordability, some of the intervenors argue the cost effectiveness or the risk spend efficiency (RSE) score of a risk mitigation should be the sole consideration to determine whether a safety program should be continued and, if so, at what level. TURN argues that, in light of affordability concerns, the Commission should use RSE scores to "weed out" PG&E's risk mitigation proposals.[24] As discussed in detail in Section 2.3 of this Reply Brief, while RSEs are one data point in selecting mitigations, other important factors must also be considered to avoid putting safety at risk. The Commission should exercise caution in reducing necessary spending for safety and reliability, even for such an important goal as affordability. PG&E RSE scores are inherently uncertain due to the nature of the data used in the modelling, the various assumptions (e.g., of mitigation effectiveness) used, the uncertain extent to which the models capture all the relevant features of the system, and the characteristics of the models themselves.[25] Given this uncertainty, the RSEs should be used with caution, and, in particular, should not be used mechanically or prescriptively as the sole factor in funding decisions.[26] The Commission should carefully consider all

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24 TURN Amended Opening Brief, pp. 6 and 17.

25 PG&E-15-E, p. 1-36, line 3 to p. 1-39, line 22.

26 See, e.g., PG&E-15-E, p. 1-39, lines 3-4 (Q: How does uncertainty in RSEs inform PG&E's use of RSEs? A: RSEs are best used to inform decisions alongside other considerations….)

evidence including expert opinion before making a decision on a utility safety program and not ignore other evidence supporting the need for safety and reliability programs as TURN urges.[27] The Commission never intended the RSEs to be determinative in making safety and reliability investments decision.[28] It should continue to consider all evidence carefully as it has historically done in GRCs, including whether PG&E's proposed replacement rates of aging assets is needed to achieving a steady state of replacement of aging assets to prevent failures.[29]

1.1.4 PG&E Has Demonstrated Its Ability To Execute On Ambitious Risk Reduction Projects To Keep Our Customers And Workforce Safe, But Needs Flexibility For New Programs And Activities.

Cal Advocates expresses doubt whether PG&E will be able to deliver on some of its promises in this proceeding, specifically the undergrounding initiative.[30] Undergrounding 10,000 miles of powerlines in areas where wildfire is at risk is the bold action we need to meet the growing wildfire risk. We will continue to improve this program and look for more efficient and effective ways to conduct the work. Cal Advocates questions whether PG&E will be able to meet its undergrounding targets, arguing that we have "never undergrounded more than 100 miles of distribution lines in any one year" and that the miles we have undergrounded are not "the riskiest powerlines in HFTDs."[31] We acknowledge that our undergrounding targets are ambitious. However, we are establishing a robust project management organization supported by industry experts that will position us to successfully ramp up our undergrounding program and meet our mileage targets. As noted above, we have doubled our undergrounding miles this year compared to last year and are on track to complete 175 miles this year.[32]

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27 CUE Opening Brief, p. 5; Joint Utilities Opening Brief, pp. 3-7.

28 Joint Utilities Opening Brief, p. 7.

29 CUE Opening Brief, p. 5.

30 Cal Advocates Amended Opening Brief, pp. 2-3.

31 Cal Advocates Amended Opening Brief, p. 3.

32 From January through November 2022, we finished undergrounding 137 miles of our 175-mile goal for 2022 and we remain on track to meet the 175-mile goal by year end.

As with any initiative in the early stages of planning and development, our plans for the 10,000-mile undergrounding program will necessarily continue to be dynamic and evolve. In our February 25, 2022 testimony (Exhibit PG&E-4), we proposed to underground approximately 3,300 miles from 2023 to 2026,[33] with the remainder of the undergrounding program to be addressed in subsequent proceedings. PG&E has since continued to evaluate its undergrounding plans and is adjusting the mileage pace in the 2023-2026 period as follows: 350 miles in 2023; 450 miles in 2024, 550 miles in 2025, and 750 miles in 2026, for a total of 2,100 miles during the 2023 GRC period. The adjustment is consistent with PG&E's commitment to most effectively implement its undergrounding proposal. Among other benefits, the reduced pace will decrease costs in the initial years of the program, therefore mitigating the bill impact on customers. The adjustment is also consistent with recommendations made by several intervenors for PG&E to reduce pace of the program. Although PG&E plans to reduce the proposed undergrounding mileage in the 2023-2026 period, PG&E remains fully committed to complete 10,000 miles of undergrounding to maximize wildfire risk reduction in the highest wildfire risk areas, in order to protect customers and communities from wildfire and other risks from electric distribution equipment and operations.

1.2 Summary Of Recommendations

PG&E is seeking a total revenue requirement in this proceeding of $3,605 million for test year 2023.[34] PG&E is also requesting attrition year increases of $924 million for 2024, $438 million for 2025 and $247 million for 2026. These amounts are calculated using the escalation factors in PG&E's Update Testimony.[35]

PG&E's updated revenue requirement in this Reply Brief is summarized in Attachment A. Attachment A compares PG&E's requested revenue requirement to the Joint Comparison

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33 PG&E-04, p. 4.3-51, Table 4.3-11, sum of lines 5 and 8.

34 Appendix A, p. A-1.

35 PG&E-33, see Appendix A, p. A-2.

Exhibit[36] to reduce the request consistent with a settlement and stipulations we have reached with the parties following evidentiary hearings and the revised undergrounding plans. The new revenue requirement request includes: (1) a settlement of wildfire liability insurance filed on October 7, 2022, which reduces PG&E's 2023 test year request by $307 million and continues to reduce the anticipated revenue requirement in the attrition years; (2) stipulations with Cal Advocates and TURN that resolve all issues in the following exhibits: Energy Supply Exhibit (PG&E-05); Information Technology, EDM and ERIM (PG&E-07); and Administrative and General (PG&E-09); and (3) PG&E's revised mileage proposals for undergrounding in HFTD areas.

1.2.1 Summary Of Requests

PG&E requests the Commission to make the following findings in its final decision in this proceeding.[37]

- The Commission should approve PG&E's updated revenue requirement presented in Attachment A to this Reply Brief.
- The Commission should find that the appropriate burden of proof for PG&E is preponderance of the evidence and that PG&E has met this burden in this proceeding.
- The Commission should confirm that parties opposing PG&E's proposals have the burden of coming forward with evidence to disprove such proposals.
- The Commission should approve PG&E's forecast ratemaking proposals and decline party proposals to require costs that can be reasonably forecast to be recorded to memorandum accounts and recovered through later application proceedings as these forecasts are well supported in this GRC and delaying recovery on a recorded basis would harm PG&E's financial health.
- The Commission should not adjust the rate of return for capital for any projects or programs as the rates are set in the Cost of Capital proceedings.

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36 PG&E-64.

37 The proposed list of findings is not intended to be exhaustive of all findings the Commission may make in a final decision for this proceeding, and is only intended to identify key findings supporting approval of PG&E's request in this proceeding and denying certain recommendations made by intervenors. PG&E's Opening Brief and Reply Brief contain other recommendations not identified in this summary list.

- The Commission should deny TURN's proposals to cap PG&E's spending in this GRC at the Consumer Price Index (CPI) as it is completely unrelated to costs to operate a utility and such a requirement would violate the Rate Case Plan, regulatory compact, and long-standing cost of service ratemaking principles.
- The Commission should deny TURN's proposal to require PG&E to provide an alternate spending proposal in the 2027 GRC that is capped at the CPI as inconsistent with the rate case plan, regulatory compact, and long-standing cost-of-service ratemaking principles.
- The Commission should approve each of the uncontested non-forecast items identified in Appendix B, Table B-4 of the Opening Brief.

1.2.2 Risk Management

- The Commission should find that PG&E's approach to risk management and safety, as described in Section 2 of PG&E's Opening Brief and this Reply Brief, is reasonable and prudent.
- The Commission should find that PG&E's description of Public Safety Power Shutoff (PSPS) consequences complies with the Risk Assessment and Mitigation Phase (RAMP) requirements for the reasons discussed in Section 2.1.2.1 of this Reply Brief.
- The Commission should find that PG&E has complied with the Commission's Risk-Based Decision-Making Framework Requirements for the reasons described in Section 2.1.2.3 of this Reply Brief.
- The Commission should reject TURN's proposal to convert RSE values into a benefit-cost ratio methodology for the reasons discussed in Section 2.3.1 of PG&E's Opening Brief and Section 2.3.2 of this Reply Brief.
- The Commission should reject TURN's proposals for recalculating PG&E's Multi-Attribute Value Function (MAVF) and RSE values for the reasons discussed in Section 2.3.1 of PG&E's Opening Brief and Section 2.3.3 of this Reply Brief.
- The Commission should reject Cal Advocates' recommendation that PG&E be required to calculate RSEs for all Maintenance Activity Type (MAT) codes for all future GRC applications for the reasons discussed in Section 2.3.3 of the Opening Brief and Section 2.3.4 of the Reply Brief.

1.2.3 Gas Operations

- The Commission should find that the proposed revenue requirement for the gas transmission, distribution, and storage functions in 2023 and related proposals are just and reasonable and that PG&E may reflect the adopted gas transmission, distribution, and storage revenue requirement in rates effective January 1, 2023.

- The Commission should approve the new Gas Operations balancing and memorandum accounts described in Appendix B, Table B-5 of the Opening Brief.
- The Commission should find that PG&E's Gas Operations testimony in Exhibit PG&E-03 reasonably addressed risk consistent with Commission decisions and direction for the reasons discussed in Section 3.2 of the Opening and Reply Briefs.
- The Commission should reject TURN's proposal regarding employee performance metrics related to In-Line Inspection (ILI) Upgrades as described in Section 3.4.1.3 of the Opening Brief.
- The Commission should reject TURN's proposals to significantly reduce ILI Upgrades and associated reassessment and direct examination and repair (DE&R) forecasted units and costs for the reasons discussed in Section 3.4.1 of the Opening and Reply Briefs.
- The Commission should reject TURN's proposals to eliminate and/or significantly reduce the Vintage Pipe Replacement and Shallow and Exposed Pipe (Including Water and Levee Crossing) programs for the reasons discussed in Sections 3.4.4 and 3.4.5 of the Opening Brief and Sections 3.4.6 and 3.4.8 of the Reply Brief.
- The Commission should approve PG&E's proposal to convert the Transmission Integrity Management Program (TIMP) Balancing Account (TIMPBA) to a two-way balancing account and the associated filing requirements for the TIMPBA and eliminate the TIMP Memorandum Account (TIMPMA) for the reasons stated in Section 3.4.7 of the Opening Brief and Section 3.14.2 of the Reply Brief. If the Commission does not approve PG&E's primary proposals for the TIMPBA and TIMPMA, the Commission should approve PG&E's alternative proposal to expand the TIMPMA to include TIMP costs above the adopted amounts for the reasons stated in Section 3.4.7 of the Opening Brief and Section 3.14.2 of the Reply Brief.
- The Commission should approve PG&E's proposal to eliminate the ILI Balancing Account (ILIBA) and ILI Memorandum Account (ILIMA) for the reasons stated in Section 3.4.8 of the Opening Brief and Section 3.14.3.1 of the Reply Brief.
- The Commission should approve PG&E's proposal to eliminate the Internal Corrosion Direct Assessment (ICDA) Memorandum Account (ICDAMA) for the reasons stated in Section 3.4.9 of the Opening Brief and Section 3.14.3.2 of the Reply Brief.

- The Commission should approve PG&E's updated Peak Day Supply Standard for the reasons stated in Section 3.6.2 of the Opening Brief and Section 3.6.1 of the Reply Brief.
- The Commission should reject the hourly curtailment proposals of SCGC/PA and TURN for the reasons stated in Section 3.6.3 of the Opening Brief and Section 3.6.2 of the Reply Brief.
- The Commission should approve PG&E's proposal to retain the Los Medanos gas storage facility, drill three new wells at the McDonald Island gas storage facility, and install cross-compression to address the capacity shortfall identified in the updated Peak Day Supply Standard for the reasons stated in Section 3.6.4 of the Opening Brief and Sections 3.6.1 to 3.6.3 of the Reply Brief.
- The Commission should reject proposals by Wild Goose, LGS and TURN to consider contracting for capacity at Independent Storage Provider (ISP) gas storage facilities or to purchase ISP facilities for the reasons stated in Section 3.6.4 of the Opening Brief and Section 3.6.3 of the Reply Brief.
- The Commission should reject proposals by Wild Goose and LGS to study potential new interconnection of ISP facilities into PG&E's gas transmission and/or distribution system for the reasons stated in Section 3.6.3 of the Reply Brief.
- The Commission should adopt the proposed changes to the Gas Storage Balancing Account (GSBA) proposed by PG&E for the reasons stated in Section 3.6.10 of the Opening Brief and Section 3.14.1 of the Reply Brief.
- The Commission should reject the reductions recommended by parties for the following disputed programs: Fitting Mitigation Program; Cross Bore Program; Gas Pipeline Replacement Program; Plastic Pipe Replacement Program; and Reliability Service Replacement Program for the reasons stated in Section 3.3 of the Opening and Reply Briefs.
- The Commission should reject the reductions recommended by parties for the following disputed programs in the in the Asset Family – Facilities: GT Routine C&P Program; GT M&C Terminal Upgrades (Brentwood Terminal Rebuild); GT and GD M&C Station OPP Enhancements Program; HPR Program; Los Medanos Compressor Replacement; and Tionesta Compressor Station Retirement for the reasons stated in Section 3.5 of the Opening and Reply Briefs.
- The Commission should reject the reductions recommended by parties for the following disputed Gas Operations and Maintenance programs: Locate and Mark; Standby Governance; Meter Protection Program; Relocation of Meter Sets as discussed in Section 3.7 of the Opening and Reply Briefs.
- The Commission should reject the forecast reductions recommended by parties for the following disputed Gas Operations Corrosion Control programs: GD Atmospheric Corrosion Mitigation – Mains; GD Atmospheric Corrosion

Mitigation – Services; GD Capital Corrosion Control; GT&S Corrosion Control Capital Expenditures for the reasons stated in Section 3.8 of the Opening and Reply Briefs.

- The Commission should approve PG&E's proposal to eliminate the Internal Corrosion Balancing Account (ICBA) for the reasons stated in Section 3.14.3.2 of the Opening Brief and Section 3.14.3.3 of the Reply Brief.

- The Commission should reject the reductions recommended by parties for the following disputed Gas Operations Leak Management programs: Below Ground Distribution Main Leak Repair; Distribution Meter Set Leak Repair; Below Ground Distribution Service Replacement; Transmission Leak Repair for the reasons stated in Section 3.9 of the Opening and Reply Briefs.

- The Commission should approve PG&E's proposal to continue the New Environmental Regulations Balancing Account (NERBA) for the reasons stated in Section 3.14.3.3 of the Opening Brief and Section 3.14.3.4 of the Reply Brief.

- The Commission should reject the reductions recommended by Parties for the following disputed Gas System Operations programs: Gas Distribution Control Center (GDCC) Operations; Gas Distribution Manual Field Operations; Gas Transmission Control Center Operations; Electric Power for Compressor Fuel and Other Electric Equipment; Gas Distribution SCADA Visibility Program; Gas Transmission SCADA Visibility Program; Gas Transmission Capacity for Load Growth for the reasons stated in Section 3.10 of the Opening and Reply Briefs.

- The Commission should reject the reductions recommended by parties for the following disputed Other Gas Operations Support programs: Butte Rebuild – Capital and Expense; CEMA Straight Time Labor Program – Expense and Capital; Gas R&D and Deployment; StanPac -- Expense and Capital for the reasons stated in Section 3.12 of the Opening and Reply Briefs.

- The Commission should adopt TURN's proposed increase to the Other Gas Operations Support (Alternative Energy Program) forecast but reject the detailed reporting on the Alternative Energy Program recommended by TURN. Instead, the Commission should approve PG&E's proposal for a workshop hosted by Commission Staff to define reporting requirements if reporting is deemed desirable by the Commission for the reasons stated in Section 3.12.4 of the Opening and Reply Briefs.

- The Commission should reject the reductions recommended by parties for the following disputed New Business and Work at the Request of Others programs: Gas Transmission Expense Work at the Request of Others; Gas Transmission (GT) New Business (NB) Program for the reasons stated in Section 3.13 of the Opening and Reply Briefs.

- The Commission should adopt the Stipulation on the Gas Distribution Capital New Business program (MWC 29) between PG&E and TURN as described in Section 3.13.2 and appended as Appendix C to this Reply Brief, including approving establishment of a new one-way balancing account to track MWC 29 new business connection costs, the Gas Distribution New Business Balancing Account (GDNBBA), as discussed in Section 13.14.3.5 of this Reply Brief.

- The Commission should adopt PG&E's revised forecast for the Gas Transmission Work at the Request of Others Program (MAT 83A) of $16 million in 2023 capital expenditures based on PG&E's agreement to reduce its forecast as proposed by TURN for the reasons stated in Section 3.13.4 of the Opening and Reply Briefs.

1.2.4 Electric Distribution

- The Commission should find that the proposed revenue requirement for the electric distribution function in 2023 and related proposals are just and reasonable and that PG&E may reflect the adopted electric distribution revenue requirement in rates effective January 1, 2023.

- The Commission should reject Cal Advocates' recommendation to require 80 percent of PG&E's underground mileage to occur in the top 10 percent of risk-ranked circuit segments in the HFTD areas for the reasons discussed in Section 4.2.2.2 of this Reply Brief.

- The Commission should reject Cal Advocates' recommendations that PG&E include a cost benefit analysis that considers alternatives to undergrounding or some combination of undergrounding and such alternatives for the reasons discussed in Section 4.2.2.2 of this Reply Brief.

- The Commission should reject Cal Advocates' recommendation to establish a graduated unit cost cap structure for undergrounding and overhead hardening work for the reasons discussed in Section 4.3.1.4.3 of this Reply Brief.

- The Commission should reject Cal Advocates' recommendations to establish six new reporting requirements related to PG&E's system hardening program for the reasons discussed in Section 4.3.1.7.1 of its Opening Brief and Section 4.3.1.6.2 of this Reply Brief.

- The Commission should reject TURN's recommendation for an alternate 10-year hardening program with a total of 500 miles of undergrounding and 4,500 miles of overhead system hardening for the reasons discussed in Sections 4.3.2.2.3 of PG&E's Opening Brief.

- The Commission should reject TURN's recommendation to issue an order restricting PG&E's discretion to replace certain assets as part of overhead system hardening for the reasons discussed in Section 4.3.2.2.1 of PG&E's Opening Brief.

- The Commission should reject TURN's recommendation to set a forecast for overhead system hardening based on a unit cost of $0.8 million per mile for the reasons discussed in Section 4.3.2.2.3 of PG&E's Opening Brief.

- The Commission should reject TURN's recommendation that the Commission set a reasonableness cap on undergrounding unit costs of $3.0 million per mile for the reasons discussed in Section 4.3.1.7.4 of PG&E's Opening Brief and Section 4.3.1.4.3 of this Reply Brief.
- The Commission should reject TURN's recommendation that the Commission require PG&E to conduct at least 90% of its system hardening on circuits containing the top 50% of wildfire risk for the reasons discussed in Section 4.3.1.7.4 of PG&E's Opening Brief and in Section 4.2.2.2 of this Reply Brief.
- The Commission should reject TURN's proposal that in the event the Commission approves PG&E's undergrounding proposal, the Commission only authorize PG&E to earn only the debt return on the capital spending for the reasons discussed in Sections 2.5.3.3 and 4.3.1.7.4 of PG&E's Opening Brief and in Section 2.5.3.2 of this Reply Brief.
- The Commission should reject AT&T's recommendation to institute a rulemaking to address regulatory uncertainties related to the impact of undergrounding communications facilities for the reasons discussed in Section 4.3.1.5.1 of this Reply Brief.
- The Commission should reject CFBF's recommendation regarding the type of programs PG&E can forecast in its GRC for the reasons discussed in Section 4.3.1.6.3 of this Reply Brief.
- The Commission should reject CFBF's recommendation around quantifying and guaranteeing long-term savings related to undergrounding for the reasons discussed in Section 4.3.1.6.3 of this Reply Brief.
- The Commission should reject CFBF's recommendation regarding cost per mile and time limits for undergrounding projects the reasons discussed in Section 4.3.1.6.3 of this Reply Brief.
- The Commission should resolve uncertainty regarding the recovery of straight time labor costs by finding that PG&E's proposal to establish a CEMA Straight Time Labor Balancing Account is reasonable for the reasons discussed in Section 4.6.3 of the Opening Brief and Section 4.6.4 of this Reply Brief.
- The Commission should reject Cal Advocates' recommendation that PG&E's Routine and Enhanced Vegetation Management costs for any given year be subject to reasonableness review if they exceed 125 percent of the five-year average of Vegetation Management costs for the reasons discussed in Section 4.9 of the Opening and Reply Briefs.
- The Commission should reject Cal Advocates' proposal to require PG&E to implement process changes to its Project Estimating Tool for the reasons discussed in Section 4.20.2 of this Reply Brief.

- The Commission should reject Cal Advocates' proposal to remove PG&E's forecasts for the Advanced Distribution Management System Release 3 and the Distributed Energy Resources Management System from the GRC and instead evaluate them in a separate proceeding coordinated with R.21-06-017 for the reasons discussed in Section 4.21.3 of PG&E's Opening Brief.

- The Commission should approve PG&E's request to recovery Community Rebuild Program costs for years 2023-2026 in this GRC for the reasons discussed in Section 4.23 of this Reply Brief.

- The Commission should find that it is appropriate for PG&E to continue using the two-way Wildfire Mitigation Balancing Account (WMBA) and should approve PG&E's proposal to raise the WMBA reasonableness threshold from 115 to 125 percent (rejecting TURN's proposal to modify the account to a one-way balancing account with no review threshold) for the reasons discussed in Section 4.24.1 of PG&E's Opening and Reply Briefs.

- The Commission should find that it is appropriate for PG&E to continue using the two-way Vegetation Management Balancing Account (VMBA) and should approve PG&E's proposal to raise the threshold for recorded amounts that can be recovered in the VMBA through a Tier 2 Advice Letter from 120 percent of adopted values to 125 percent of adopted values (rejecting TURN's proposal to modify the account to a one-way balancing account with no review threshold) for the reasons discussed in Section 4.24.2 of PG&E's Opening and Reply Briefs.

- The Commission should reject TURN's proposal to create a Wildfire Mitigation Memorandum Account (WMMA) as a ratemaking mechanism for recording above-authorized wildfire mitigation spending, subject to an after-the-fact reasonableness review, for the reasons discussed in Section 4.24.1 of PG&E's Reply Brief.

1.2.5 Energy Supply

- The Commission should find that the proposed revenue requirement for Energy Supply, as modified by the stipulations addressing contested Energy Supply issues with TURN and Cal Advocates, included as Exhibit PG&E-30 (Hydro Decommissioning), Appendix E to the Opening Brief (stipulation with TURN), and Appendix B to the Reply Brief (stipulation with Cal Advocates) are just and reasonable and that PG&E may reflect the revenue requirement in rates effective January 1, 2023.

- The Commission should reject the JCCA's proposals for re-vintaging utility-owned generation for the reasons discussed in Section 5.8.4 of PG&E's Opening and Reply Briefs.

1.2.6 Customer And Communications

- The Commission should approve PG&E's Gas Advanced Metering Initiative (AMI) Proactive Replacement Project as the least-cost option to replace failing gas modules and find that PG&E has been a prudent manager of its Gas AMI program and entitled to a full rate of return for the reasons discussed in Section 6.10 of PG&E's Opening and Reply Briefs.
- The Commission should approve PG&E's Billing System Upgrade Project and reject TURN's recommendation that PG&E be required to resubmit supporting documentation for the reasons discussed in Section 6.11 of PG&E's Opening and Reply Briefs.
- The Commission should reject Cal Advocates' and TURN's suggestion that PG&E's non-tariffed products and services will not see an increase in demand for the reasons discussed in Section 6.3 of PG&E's Opening and Reply Briefs.
- The Commission should reject TURN's proposal to disallow the reasonable compensation requested for PG&E's Regional Vice Presidents and Customer and Communications Officers consistent with Commission precedent for the reasons discussed in Sections 6.2 and 6.9 of PG&E's Opening and Reply Briefs.

1.2.7 Shared Services

- The Commission should approve PG&E's proposal to include in rate base the entire amount of the Oakland General Office purchase in 2023 and reject Cal Advocates' proposal to book the purchase price in a memorandum account as discussed in Sections 2.5.3.1 and 7.6.5.1 of PG&E's Opening Brief and Section 7.6.2.1 of this Reply Brief.
- The Commission should approve as reasonable the Enterprise Data Management (EDM)/ Information Technology (IT) Stipulation with TURN and Cal Advocates included in Appendix F in the Opening Brief as discussed in Section 7.9 of PG&E's Opening Brief.

1.2.8 Human Resources

- The Commission should find that PG&E's Short-Term Incentive Plan (STIP) is a reasonable cost of service and adopt PG&E's STIP forecast as discussed in Section 8.3.1 of PG&E's Opening and Reply Briefs.
- The Commission should adopt PG&E's forecast for its Non-Qualified Retirement, Supplemental Executive Retirement Plan (SERP) as discussed in Section 8.3.2 of PG&E's Opening and Reply Briefs.
- The Commission should adopt PG&E's forecast for its Rewards and Recognitions Program as discussed in Section 8.3.3 of PG&E's Opening and Reply Briefs.

- The Commission should adopt PG&E's labor escalation rates as discussed in Section 8.3.4 of PG&E's Opening Brief.
- The Commission should adopt PG&E's department cost forecast for PG&E Academy as discussed in Section 8.5.1 of PG&E's Opening and Reply Briefs.
- The Commission should adopt PG&E Academy's Training Expense forecast as discussed in Section 8.5.2 of PG&E's Opening and Reply Briefs.
- The Commission should adopt PG&E's Training Capital forecast as discussed in Section 8.5.3 of PG&E's Opening and Reply Briefs.
- The Commission should find that the use of an actuarial analysis to forecast medical and dental benefits is reasonable, consistent with long-standing Commission practice, reject Cal Advocates' insufficient alternate forecasts, and adopt PG&E's forecasts for these benefits as discussed in Sections 8.4.2.4 and 8.4.2.5 of PG&E's Opening Brief and Section 8.4.2.5 of PG&E's Reply Brief.
- The Commission should adopt PG&E's forecasts for the following employee benefit programs described in these Sections of PG&E's Opening and/or this Reply brief: (1) medical and dental (Section 8.4.2.4); (2) Retirement Savings Plan forecast (Section 8.4.3.1); (3) Retirement Excess Plan forecast (Section 8.4.3.2); (4) Relocation (Section 8.4.4.1); and (5) Commuter Benefits (8.4.4.2).

1.2.9 Administrative And General (A&G):

- The Commission should approve as reasonable the A&G Stipulation with TURN and Cal Advocates included as Appendix G in the Opening Brief.

1.2.10 Results Of Operation, Working Cash, And Rate Base, And Other Financials

- The Commission should approve PG&E's proposals for: (1) the projected level of customer deposits for 2023; (2) the revenue lag and bank lag; (3) the expense lag associated with goods and services expense; and (4) the expense lags associated with federal and state income tax expense as described in Section 10.3 of PG&E's Opening and Reply Briefs.
- The Commission should approve PG&E's proposals to update its rate base to reflect its capital expenditures as described in Section 10.4 of PG&E's Opening and Reply Briefs.
- The Commission should approve the Other Operating Revenues that PG&E receives from transactions not directly associated with the distribution, generation, gas transmission, or sale of electric energy or natural gas described in Section 10.5 of PG&E's Opening Brief.

- The Commission should approve PG&E's calculation method and resulting 2023 forecast for payroll taxes and other taxes described in Section 10.7 of PG&E's Opening Brief.

- The Commission should approve the A&G allocation factor and the franchise fee factor described in Section 10.8 of PG&E's Opening Brief.

1.2.11 Post Test Year Ratemaking (PTYR)

- The Commission should adopt PG&E's PTYR mechanism as described in Section 11 of PG&E's Opening and Reply Briefs.
- The Commission should affirm that the capital and expense portion of PG&E's PTYR mechanism should be determined separately.
- The Commission should find that use of the CPI is not a measure of utility costs and is insufficient to compensate PG&E for reasonable growth in its expenses (including wages) during the post test year period.
- The Commission should find that PG&E's proposed modifications to its Z-Factor tariff are reasonable and should be adopted.

1.2.12 General Report Including Balancing Accounts And Memorandum Accounts

- The Commission should approve as reasonable PG&E's uncontested proposals for continuation, creation, modification, or closure of balancing and memorandum accounts as summarized in Appendix B, Tables B-1 through B-3 of PG&E's Opening Brief.
- The Commission should approve as reasonable PG&E's contested proposals for the continuation, creation, modification, or closure of balancing and memorandum accounts as summarized in Appendix C, Tables C-1 through C-4 of PG&E's Opening Brief.
- The Commission should approve discontinuation of certain reporting requirements in D.15-04-024 regarding the Shareholder Funded Gas Transmission Safety Account as described in Section 12.2 of PG&E's Opening Brief.

1.2.13 Update Testimony

- The Commission should adopt PG&E's updated escalation factors based on the IHS Market Second Quarter 2022 report to reflect the impacts of inflation on PG&E's base year costs as discussed in Section 13 of PG&E's Opening and Reply Briefs.
- The Commission should approve PG&E's three updates for federal income tax: (1) Adjustments to Comply with the Internal Revenue Code (IRC) Normalization Rules; (2) Corporate Minimum Tax in the Inflation Reduction Act (IRA) of

2022; and (3) Gas Transmission (GT) Accounting Method Change pursuant to automatic change rules under Revenue Procedure 2022-14[38] as discussed in Section 10.2.2 of PG&E's Opening and Reply Briefs.

- The Commission should reject TURN's proposal to revise the Tax Memorandum Account as discussed in Section 10.2.2 of PG&E's Reply Brief.

1.2.14 Memorandums Of Understanding

- The Commission should approve as reasonable the Memorandums of Understanding described in Section 14 of PG&E's Opening Brief.

1.3 Affordability And Customer Impacts

1.3.1 Affordability Metrics And Rate Information

PG&E is committed to working with the Commission and stakeholders to improve affordability programs and address the challenges facing vulnerable customers while ensuring the utility has the funding necessary to provide safe and reliable service. The Commission's affordability metrics are one of the tools the Commission, parties, and PG&E use to evaluate the impact of our proposals on customer rates. In its Opening Brief, Cal Advocates implies that PG&E is evading Commission requirements and disregarding affordability asserting that "PG&E did not employ" the affordability tools developed by the Commission in its application, and that our application only provided typical residential electric and gas bill impacts.[39] Cal Advocates states that "these isolated pieces of data should be given no weight because PG&E does not state whether the increases referenced above were incremental to January 2021 or June 2021 monthly bills, or anticipated rate increases that would result from the revenue request if granted."[40]

These arguments reflect a misunderstanding of the purpose of the bill impact tables in the application, which are required by the Rate Case Plan, and misstate the record and PG&E's compliance with the Scoping Memo requirements for the affordability metrics. The Commission

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38 PG&E-33, Ch. 3, Tax Updates.

39 Cal Advocates Opening Brief, p. 17.

40 Cal Advocates Opening Brief, p. 18.

had not finalized the affordability metrics or directed their use when PG&E filed its application in June 2021. As noted in the Scoping Memo, "certain aspects of the affordability metrics remain in development" and "the Commission in D.20-07-032 did not mandate the analysis [of affordability metrics]."[41] PG&E did employ the affordability metrics and provided a report and accompanying data in February 2022, as directed in the Scoping Memo, and then provided a revised version for the Update Testimony on an expedited basis in response to a request from TURN in September 2022.[42]

Cal Advocates does not acknowledge PG&E's showings on the affordability metrics, let alone identify any deficiency, nor provide any recommendation as to what additional information Cal Advocates thinks PG&E should have provided. Instead, Cal Advocates claims PG&E has shown "reticence in providing these affordability assessments…."[43] PG&E has not shown any reticence in providing affordability metrics data in this proceeding and Cal Advocates provides no basis for this erroneous claim. On the contrary, PG&E agrees that affordability is a crucial issue and supports the goals of the Affordability Order Instituting Rulemaking (OIR) (R.18-07-006) including the development of transparent affordability metrics to consistently measure relative affordability of energy services over time.[44] Finally, Cal Advocates perplexingly argues that the Commission should "employ the tools and metrics developed in the Affordability OIR to get a comprehensive assessment of the impact of PG&E's revenue request increases, particularly the update filing," ignoring that PG&E has provided exactly this.[45]

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41 Scoping Memo, p. 8.

42 See Exhibit TURN-610E, which provides affordability tables and graphs prepared by TURN using the revised Affordability Metrics PG&E prepared to incorporate the Update Testimony and provided on September 16, 2022.

43 Cal Advocates Opening Brief, p. 18.

44 PG&E-14, p. 1-4, lines 2-17.

45 Cal Advocates Opening Brief, p. 19.

Cal Advocates recommends that the Commission "require PG&E to provide complete and consistent data on the customer impacts and affordability of the revenue requirement increases, including disclosure of past, current and forecast typical monthly bills and any information on any other pending rate increases from other applications before the Commission."[46] PG&E agrees that use of transparent affordability metrics to consistently measure relative affordability of energy services over time is important and has provided an Affordability Metrics report for the 2023 GRC, consistent with the Scoping Memo, and revised affordability metrics reflecting the Update Testimony, exceeding the requirements of the Scoping Memo and Decision (D.) 22-08-023 in the Affordability OIR. For future rate cases and applications, PG&E will provide affordability metrics consistent with the requirements of D.22-08-023.[47]

TURN claims that its analysis of the affordability metrics demonstrates that PG&E's "requested increases are not affordable for many Californians."[48] Yet the Commission has at no time defined what constitutes an affordable or unaffordable outcome. Instead, the purpose of the affordability metrics is to provide transparent and consistent information over time to aid in Commission decision-making, not to draw a bright line as to what is unaffordable. TURN is essentially asking the Commission to judge PG&E's proposals based on socioeconomic issues that are beyond the ability of a utility to control, since PG&E cannot control all factors that contribute to income levels, nor California's relatively high cost of housing, among many other issues. TURN also argues that "PG&E has not offered a feasible solution to its unaffordable

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46 Cal Advocates Opening Brief, p. 19.

47 D.22-08-023 implements the affordability metrics. Ordering Paragraphs 5 and 6 require the utilities to provide affordability metrics and analysis for any initial filing in any proceeding with a revenue increase estimated to exceed one percent of currently authorized revenues systemwide for a single fuel.

48 TURN Amended Opening Brief, p. 14.

requested increase."[49] This is simply wrong. We have explained in detail the need for each of the programs proposed in this proceeding and have worked with parties, including TURN, on settlements and stipulations that have lowered our requested revenue requirements. Moreover, we have developed novel proposals to deliver services more economically, such as through the Wildfire Insurance Settlement Agreement.[50] PG&E also supports addressing affordability holistically through the Affordability OIR.[51]

CFBF argues that "PG&E has not even conducted or has failed to share the bill impacts for any other customers other than residential customers, despite being requested to provide the bill impacts for agricultural customers by the Administrative Law Judge (ALJ) and PG&E counsel acknowledging they would do so."[52] PG&E did provide average rate impacts for all customer classes, including agricultural customers in its application.[53] CFBF did not submit a data request to PG&E seeking bill impact information. PG&E apologizes for the oversight in not following up on this request during hearings.

1.3.2 Programs To Address Affordability

Cal Advocates incorrectly claims that "PG&E argues that parties are overstating the affordability crisis" because of the availability of customer assistance programs.[54] We have never argued that any party is "overstating" the affordability crisis and the citation that Cal Advocates provides in its Opening Brief does not support this assertion. PG&E did provide information about assistance programs available to help customers as an example of how PG&E

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49 TURN Amended Opening Brief, p. 16.

50 PG&E Opening Brief, p. 772-773 and Appendix G, p. G-1 (referencing the Joint Motion of Pacific Gas and Electric Company, The Utility Reform Network and The Public Advocates Office at the California Public Utilities Commission for Expedited Approval and Adoption of the Attached Settlement Agreement on Insurance Related Issues (October 7, 2022).

51 PG&E-14, p. 1-4, lines 2-17.

52 CFBF Opening Brief, p. 4.

53 See PG&E 2023 GRC Amended Application (March 10, 2022), p. D-20.

54 Cal Advocates Opening Brief, p. 19.

is working to address affordability issues,[55] which in no way constitutes a dismissal of the very real affordability issues facing California. Moreover, the Commission in the 2020 Annual Affordability Report analyzed the California Alternate Rates for Energy Program (CARE) and Customer Assistance Program (CAP) programs (which have the same income eligibility requirements) and determined that these programs provide "a sizable improvement in utility affordability in the most vulnerable areas."[56]

Cal Advocates, TURN, AARP, and CFBF criticize PG&E's mention of customer assistance programs, arguing that these programs are not a solution to the affordability crisis in California.[57] PG&E believes that assessing these programs to ensure they are effective and expanding them so that they deliver for vulnerable Californians are essential steps in addressing affordability. The Commission is already taking up these issues in Phase 3 of the Affordability OIR.[58] The Commission will further examine strategies to contain energy cost, rate, and bill increases as part of Phase 3, including hosting a series of public town hall-style "Listening Sessions" around the state and hear from the public on regional affordability issues.[59] PG&E welcomes this dialogue and supports strengthening these programs.

Affordability issues must be carefully considered and addressed on a statewide basis with all relevant stakeholders involved. As PG&E witness Carla Peterman explained, the changing climate, and resulting severe weather and wildfire, present new risks that must be addressed,

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55 PG&E-14, p. 1-1, line 26 to p. 1-3, line 4.

56 See CPUC, 2020 Annual Affordability Report (Oct. 2022), pp. 8, 52, <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/affordability-proceeding/2020/2020-annual-affordability-report.pdf> (as of Dec. 7, 2022).

57 See Cal Advocates Opening Brief, p. 19; TURN Amended Opening Brief, p. 15; AARP Opening Brief, p. 9; CFBF Opening Brief, p. 7.

58 *Assigned Commissioner's Ruling Amending Ruling of May 20, 2022 and Further Updating Proceeding Schedule for Phase 3 of the Proceeding* (June 9, 2022), R.18-07-006.

59 *Id.*, at pp. 3-4.

while also proving the imperative of promoting clean and renewable electricity.[60] In February 2022, an *en banc* hearing in the Affordability OIR proceeding was held where participants discussed possible non-ratepayer sources of funding, particularly for wildfire mitigation and safety efforts. PG&E recognizes the significance of its critical investments to implement wildfire mitigation and support public safety and believes the challenge of long-term funding of this work is a state-wide issue properly before the Commission in the Affordability OIR. PG&E looks forward to continuing to engage with the Commission and other stakeholders to identify solutions to keeping rates affordable, including strengthening customer assistance programs and identifying non-ratepayer funding sources.

1.3.3 TURN's Consumer Price Index Proposals Should Be Denied

TURN repeats its previous arguments that PG&E should be able to operate safely and reliably with increases in spending that are capped by the CPI.[61] PG&E addressed this issue in Section 2.5.3.4 of its Opening Brief and will not repeat its response at length here. The Commission has consistently rejected arguments that utility costs should be established based on the CPI. The CPI has nothing to do with the utilities' costs or cost-of-service ratemaking. As the Commission succinctly stated in SCE's 2005 GRC:

> The CPI may be a simple, accessible measure of general inflation faced by urban U.S. consumers, but that alone does not make it appropriate as a measure of price changes faced by an electric utility. It does not specifically cover the prices of the typical goods SCE purchases. Conversely, SCE's proposed escalation rates were not designed to track the general level of inflation, and there is no reason why they should do so. . . .
>
> Apart from simplicity (and the fact that it yields a lower revenue requirement), Aglet has not demonstrated why it is appropriate to forecast SCE's cost changes using a measure of price changes faced by consumers instead of measures of price

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60 PG&E-14, p. 1-4, lines 2-4.

61 TURN Amended Opening Brief, p. 29.

> changes faced by utilities. SCE's escalation approach more accurately reflects utility purchases and will therefore be approved.[62]

TURN's proposal that the increase in spending that is authorized in PG&E's current GRC should be capped at the rate of CPI although it has nothing to do with utility prices, would lead to absurd results. TURN argues that the CPI cap should be placed on PG&E's "total GRC spending" rather than its revenue requirement.[63] There is no evidence that PG&E can operate safely and reliably at these amounts, certainly not in TURN's testimony.

TURN proposes that the utility be required to submit testimony in the next GRC explaining why price increases for utility work exceed the CPI.[64] The Commission has repeatedly determined that there is ***no*** relation between the utility's operating costs and the CPI. Thus, requiring the utility to submit testimony that explains on a program-by-program basis, as TURN suggests, why utility prices increase at a rate that differs from CPI, would be a complete waste of time for PG&E, the Commission and other parties. TURN claims that its proposal would have the benefit of avoiding "anchor bias"[65] where one makes a decision based on actual data. What TURN is seeking to avoid is a review of actual prices and verified data, i.e. proof of the actual costs the utility incurs to provide electric and gas service, including purchasing pipe, conduit, poles and other such supplies and paying for labor. The "bias" TURN seeks to avoid is the evidence of the actual costs to provide the work that the rate case plan requires utilities to submit to support their forecasts.[66]

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62 D.04-07-022, p. 278; D.14-08-032, p. 653 ("The CPI reflects consumer retail price changes, not the escalation in wholesale purchases of utility goods and services."); D.15-11-021, pp. 390-391 (same); D.19-09-051, pp. 707-708 (same); D.21-08-036, p. 547 ("As we have previously explained, the CPI reflects consumer retail price changes and does not reflect how utilities incur costs.").

63 TURN Amended Opening Brief, p. 26.

64 TURN Amended Opening Brief, p. 30.

65 TURN Amended Opening Brief, p. 31.

66 See e.g., D.89-01-040, p. B 22, par. F; 1989 Cal. PUC LEXIS 37, *76 (requiring the utility to submit workpapers with "five years of recorded data for each FERC account used in the development of the test year revenues and revenue requirement.")

TURN's CPI proposal has been raised and rejected in several proceedings, including this one,[67] and is pending in the Affordability OIR.[68] Yet TURN urges the Commission to act on it now.[69] PG&E agrees that the Commission should act on this proposal now by dismissing it as unlawful and inconsistent with cost-of-service ratemaking under which the utilities rates must be based on evidence of their actual costs of service.[70]

If the Commission wishes to entertain this proposal in the Affordability OIR, there is sufficient time to do this before PG&E's 2027 GRC is filed in May 2025.[71] In the Affordability OIR, the Commission is seeking feedback on affordability proposals through community outreach and a workshop[72] and anticipates issuing a proposed decision on the affordability proposals in Q2/Q3 2023.[73] Since the Scoping Memo contemplates a final decision in this proceeding in Q3 2023, considering the issue in one utility's GRC will not hasten the resolution

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67 Scoping Memo, p. 9; D.21-07-017, *Decision Regarding Petition for Modification of Decision 20-12-005* (Commission rejected TURN's proposal to require PG&E to file a CPI-capped forecast in the 2023 GRC); *Email Ruling Denying the Motion to Require and Inflation-Constrained Alternative*, A.20-06-012 (June 14, 2021) (rejecting TURN's proposal in PG&E's 2020 RAMP application proceeding).

68 *Assigned Commissioner's Ruling Amending Ruling of May 20, 2022 and Further Updating Proceeding Schedule for Phase 3 of Proceeding* (June 9, 2022), R.18-07-006 (Ruling Updating Proceeding Schedule), p. 2.

69 TURN Amended Opening Brief, p. 32.

70 PG&E Opening Brief, pp. 14-15. For further discussion, see Pacific Gas and Electric Company's Response to Motion of the Utility Reform Network to Require Pacific Gas and Electric Company to Supplement its Testimony with an Inflation-Constrained Alternative Spending Plan (Aug. 20, 2021); Southern California Edison Company's (U 338-E) Response To Motion Of The Utility Reform Network To Require Pacific Gas and Electric Company To Supplement Its Testimony With an Inflation-Constrained Alternative Spending Plan (Aug. 20, 2021); Southern California Gas Company (U 904 G) And San Diego Gas & Electric Company (U 902 M) Response To Motion Of The Utility Reform Network To Require Pacific Gas And Electric Company (U 39 M) To Supplement Its Testimony With An Inflation-Constrained Alternative Spending Plan (Aug. 20, 2021).

71 *Assigned Commissioner's Fifth Amended Scoping Memo and Ruling* (Jan. 18, 2022) R.18-07-006, p. 4.

72 Ruling Updating Proceeding Schedule, p. 3.

73 Ruling Updating Proceeding Schedule, p. 4.

of the issue. In any event, since TURN's proposal would radically change the way the Commission establishes rates in GRC proceedings – by requiring testimony that is no longer based on the utility's actual costs to provide service and thus is inaccurate by design – such a proposal should be litigated in a Rate Case Plan proceeding involving all utilities and interested parties if the Commission does not clearly and unequivocally dismiss the proposal here. As Commission President Batjer determined in the Scoping Memo, any requirement to change the rate case plan to require TURN's alternate proposal would necessarily involve the other utilities and thus is out of scope here.[74]

1.4 Legal And Ratemaking Principles

1.4.1 Burden And Standard Of Proof

1.4.1.1 All Parties Have A Burden To Produce Evidence Supporting Their Positions

PG&E agrees that it must shoulder the burden of showing that its forecast is reasonable. PG&E also agrees with certain of the intervenors that applicable standard of proof for the utility in GRCs is preponderance of the evidence.[75] The preponderance of the evidence means "that the evidence on one side outweighs, preponderates over, is more than, the evidence on the other side, not necessarily in number of witnesses or quantity, but in its effect on those to whom it is addressed."[76] Indicated Shippers cites a 2000 decision for the proposition that the standard is "clear and convincing evidence."[77] The Commission and Court of Appeal have since clarified

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74 Scoping Memo, p. 9.

75 PG&E Opening Brief, pp. 12-13; TURN Amended Opening Brief, pp. 5, 37; JCCA Opening Brief, p. 5.

76 *Glage v. Hawes Firearms Co.,* (1990) 226 Cal.App.3d 314, 325 (quoting *People v. Miller*, (1916) 171 Cal. 649, 652.

77 Indicated Shippers Opening Brief, p. 6.

that the appropriate standard is preponderance of the evidence rather than clear and convincing evidence.[78]

It is notable that none of the intervenors discuss their burden to produce evidence to oppose PG&E's proposals. TURN and Cal Advocates appear to deny that there is any burden on intervenors to disprove the utility's showing.[79] As discussed in PG&E's Opening Brief,[80] the Commission has repeatedly held that parties opposing a utility's programs or forecasts have the burden of going forward to produce evidence to support their own positions and raise reasonable doubt as to the utility's request.[81] Mere disagreement alone is not evidence. "[W]here other parties propose a result different from that asserted by the utility, they have the burden of going forward to produce evidence, distinct from the ultimate burden of proof."[82] TURN's Opening Brief ignores recent Commission decision on this very issue. In SDG&E and SoCalGas's 2018 GRC, TURN alleged in an application for rehearing that the Commission incorrectly shifted the burden to intervenors to disprove the utilities' proposals. The Commission disagreed:

> TURN's rehearing application repeatedly claims that we failed to hold the utilities to their burden of proof, and wrongly shifted the burden to the intervenors. [Citations omitted.] We disagree with this claim. [¶] Commission decisions consistently hold the utilities to their ultimate burden to prove the reasonableness of the relief they seek and the costs they seek to recover. Yet 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. [¶] Although we agree our Decision can be modified in some respects, in most instances where TURN claims the burden was shifted, *TURN merely failed to meet its burden of going forward*. In addition, just because an intervenor's recommendations may not prevail does not mean we improperly shifted the burden.[83]

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78 D.11-05-018, pp. 68-69; D.19-05-020, p. 7 (citing D.15-11-021, pp. 8-9); see also *Utility Consumers' Action Network v. Public Utilities Com.,* (2010) 187 Cal. App.4th 688, 699.

79 TURN Amended Opening Brief, p. 42; Cal Advocates Opening Brief, p. 20.

80 PG&E Opening Brief, p. 13.

81 D.20-07-038, pp. 3-4; D.22-06-032, p. 7; See also D.18-12-009, p. 12; D.18-07-006, p. 15; D.16-05-024, p. 10; and D.15-03-049, p. 6. (Each decision cites D.87-12-067, 27 CPUC 2d 1, 22).

82 D.08-01-022, p. 4.

83 D.20-07-038, pp. 3-4 (emphasis added).

Thus, to the extent PG&E has met its burden of proof and its proposals are uncontested or the party opposing a forecast does not submit evidence raising a reasonable doubt as to the utility's position,[84] PG&E's forecasts should be approved.

1.4.1.2 The Prudent Manager Standard Does Not Justify Proposals To Deny PG&E's Reasonable Costs Of Service

TURN also discusses the "Prudent Manager Standard" and argues that this standard justifies denial of PG&E's forecast costs for the Gas Advanced Metering Initiative (AMI) replacement project and the Community Rebuild Program.

The Commission recently described this standard as follows:

> The Commission uses the established prudent manager standard to evaluate whether SCE's requested costs are just and reasonable. The Commission has described this standard as follows: The term "reasonable and prudent" means that at a particular time any of the practices, methods, and acts engaged in by a utility follows the exercise of reasonable judgment in light of facts known or which should have been known at the time the decision was made. The act or decision is expected by the utility to accomplish the desired result at the lowest reasonable cost consistent with good utility practices. Good utility practices are based upon cost-effectiveness, reliability, safety, and expedition.
>
> The prudent manager standard is not a standard of perfection. The Commission has explained that:
>
> A reasonable and prudent act is not limited to the optimum practice, method, or act to the exclusion of all others, but rather encompasses a spectrum of possible practices, methods, or acts consistent with the utility system needs, the interest of the ratepayers and the requirements of governmental agencies of competent jurisdiction.[85]

TURN continues to erroneously describe PG&E's forecast for the Community Rebuild Program as comprised "entirely of activities PG&E is undertaking to restore service and rebuild facilities destroyed by the Camp Fire . . . ."[86] As PG&E established in its testimony, its costs to restore service due to the Camp Fire were paid by PG&E shareholders due to a settlement

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[84] Commission decisions must be based on substantial evidence. Pub. Util. Code, § 1757(a)(3), (4).

[85] D.22-06-032, p. 8.

[86] TURN Amended Opening Brief, pp. 42-43.

regarding, among other issues, cost recovery for the rebuild costs.[87] Decision 20-05-019 established the amount of the penalty and cost disallowance resulting from the Camp Fire. The costs that PG&E seeks in this proceeding are for the installation of new electric underground infrastructure in the Town of Paradise to mitigate against future wildfire risk in that area following the 2018 Camp Fire.[88] The undergrounding of assets will help reduce wildfire risks from power lines in the area, which lies mostly in Tier 2 and 3 HFTD areas and help ensure access to safe egress routes if there is another wildfire (regardless of source of ignition).[89] Thus the undergrounding PG&E proposes would be appropriate regardless whether there was a previous fire in this area. The costs sought for the rebuild are not the result of imprudent activity, as TURN alleges, rather PG&E requests the cost of wildfire mitigation activities necessary to avoid future wildfires in the same areas.

To the extent the prudent manager standard applies to our request for cost recovery to replace defective AMI meters, PG&E's conduct meets this standard. As discussed above, the prudent manager standard does not hold a utility to a requirement of perfection. "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."[90] We strongly disagree with TURN that PG&E has not met its burden to show the reasonableness of its actions and with Cal Advocates that the module failure indicates imprudence by PG&E.[91] As PG&E established in its testimony and discussed in its Opening Brief, PG&E acted reasonably in the operation of the Gas AMI program, from its selection of the vendor and equipment, installation of the devices, discovery of the premature meter failures,

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87 PG&E-14, p. 3-6, line 13 to p. 3-7, line 2.

88 PG&E-04, p. 23-1, lines 11-14.

89 PG&E-04, p. 23-11, lines 21-26.

90 D.22-06-032, p. 18.

91 TURN Amended Opening Brief, p. 542; Cal Advocates Opening Brief, p. 53.

efforts to mitigate the impact of their failure, and, most recently, its dispute resolution with the vendor, which has resulted in an agreement that will significantly offset costs that otherwise are appropriate for customer funding. For more discussion of this program, see PG&E's Opening Brief, Section 6.10 and additional discussion in Section 6.10 below.

1.5 Use Of PG&E's 2021 Forecast And Recorded Cost Data

Cal Advocates continues to dispute whether PG&E complied with Commission requirements to produce its 2021 recorded data. As noted by Cal Advocates, the issue of when PG&E would provide recorded 2021 data was discussed at the pre-hearing conference. PG&E explained that it could provide final verified 2021 recorded data in a useable format for the parties by March 31, 2022.[92] The Scoping Memo required PG&E to produce 2021 recorded year data by March 22 or 31, 2022.[93] PG&E provided the final 2021 data on March 9, 2022, which was earlier than required.[94]

Cal Advocates propounded many data requests for the 2021 recorded data before it was due.[95] PG&E provided partial year recorded data when available following the issuance of the Scoping Memo, but indicated to Cal Advocates in response to data requests in Q4 2021 and Q1 2022 that it would not be able to continue to update the 2021 partial year recorded year data in discovery responses and would provide **final** verified 2021 recorded data in March 2022

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92 Cal Advocates Opening Brief, p. 27. The Scoping Memo had inconsistent dates for the production of 2021 data: March 22, 2022 and March 31, 2022. See Scoping Memo, pp. 5-6, 14.

93 Scoping Memo, pp. 5-6, 14.

94 PG&E-14, p. 2-4, lines 5-18 (internal footnotes omitted). The recorded costs are included in PG&E-23-E, Chapter 10. The recorded costs were inadvertently omitted from PG&E 23-E Chapter 10. PG&E discovered this omission in preparing its Opening Brief. PG&E filed a motion to replace PG&E-23 with a version that contains the missing Chapter 10 on November 2, 2022, which was approved by an email ruling of the Administrative Law Judges on November 22, 2022.

95 See Exhibits CALPA X-2, CALPA X-3, CALPA X-4, CALPA X-5, CALPA X-6, CALPA X-7, CALPA X-8 and CALPA X-9.

pursuant to the Scoping Memo.[96] Cal Advocates served its prepared testimony on June 13, 2022, or ***96 days*** after its receipt of PG&E's 2021 recorded data. Cal Advocates in several instances used in its testimony PG&E's 2021 recorded data that PG&E provided in March.[97] However, for other programs, Cal Advocates used a mixture of PG&E's interim (unverified) recorded data provided in discovery responses and Cal Advocates' own forecast for some of the later months in 2021. Thus, Cal Advocates' presentation of the 2021 recorded data is inconsistent with the actual 2021 recorded data and PG&E's presentation of the prior years' recorded data.

Cal Advocates requests the following findings about PG&E's production of 2021 recorded data: (1) Cal Advocates' statutory right to discovery trumps the Commission's right to establish a date for production of the recorded year data in a Scoping Memo; (2) the Commission should require PG&E to continuously provide recorded data for the year following the base year in a GRC proceeding on a rolling basis; (3) the Commission should approve of Cal Advocates' inconsistent use of 2021 recorded data. As we discuss below, Cal Advocates' positions are without merit.

1.5.1 Cal Advocates Statutory Right To Discovery Does Not Trump The Assigned Commissioner's Scoping Memo

Cal Advocates claims that "[t]he Scoping Memo did not address Cal Advocates' right to recorded data when available as the Commission has always recognized where Cal Advocates' rights to discovery is established by statute."[98] Notably, this is the first time in this proceeding that Cal Advocates has claimed that portions of the Scoping Memo did not apply to it although it is a party to the proceeding. Cal Advocates did not take this position at the prehearing conference when the production of the 2021 recorded data was discussed. While Cal Advocates

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96 *Ibid.*

97 Cal Advocates Opening Brief, pp. 187-188; see also p. 189, fn. 823.

98 Cal Advocates Opening Brief, p. 27.

does not identify the statute it references, PG&E understands that Cal Advocates is referring to Public Utilities Code Section 309.5(e) which allows Cal Advocates to request data from utilities, but it also contains a dispute resolution mechanism that Cal Advocates did not follow. That section provides:

> The [Public Advocates] office may compel the production or disclosure of any information it deems necessary to perform its duties from any entity regulated by the commission, provided that any objections to any request for information shall be decided in writing by the assigned commissioner or by the president of the commission, if there is no assigned commissioner.[99]

Section 309.5(e) specifically contemplates that a utility may object to Cal Advocates' data request. Here, PG&E appropriately objected to certain of the data requests by indicating the timing of its production of the data was established in the Scoping Memo.[100] In any event, PG&E did not deprive Cal Advocates of the data it was requesting as it repeatedly claims in its Opening Brief.[101] PG&E produced the data earlier than required, *giving Cal Advocates more than 3 months to analyze the recorded data and use it in testimony*.

Cal Advocates did not file a discovery motion concerning PG&E's production of the recorded data in March 2022 consistent with the statute that it now claims exempts it from compliance with the Scoping Memo schedule for production of the same data. If Cal Advocates believed the Scoping Memo schedule for production of recorded data did not apply to it because of its "statutory rights," as it now claims, it should have brought that dispute to the attention of the Assigned Commissioner consistent with the dispute resolution mechanism in the statute it now says is controlling. There is no reasonable dispute that PG&E fully complied with its obligation to produce the data according to the Scoping Memo. Cal Advocates had more than three months to analyze the data and use it in its prepared testimony. Neither its belated

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99 Pub. Util. Code, § 309.5(e).

100 See CALPA X-2, CALPA X-3, CALPA X-4, CALPA X-5, CALPA X-6, CALPA X-7, CALPA X-8 and CALPA X-9.

101 Cal Advocates Opening Brief, pp. 20-21, 26-28, 152, 187-188.

complaints about discovery responses which it chose to not timely raise, nor its intentional failure to analyze data in its possession for more than three months before its testimony was due, support its erroneous and inconsistent use of PG&E's recorded data. The time period for Cal Advocates to review the recorded data is longer than in a typical GRC proceeding. For example, in the SoCalGas and SDG&E 2024 GRC proceeding, the parties will have **14** days after the submission of the utilities' 2022 recorded data to serve their testimony.[102] Cal Advocates has no basis to complain that a 96-day period was insufficient for it to use the recorded data.

1.5.2 It Was Appropriate For The Assigned Commissioner To Establish A Schedule For Production Of Base Year + One Data In The Second Quarter Of 2022

Cal Advocates indicates that the Commission should establish rules *in this proceeding* for the production of recorded data *in future GRC proceedings* that would allow Cal Advocates to request the recorded data continuously and to receive nine months of recorded data in January of the year after the GRC application is filed.[103] This proposal should be denied.

The production of base year plus one recorded year data should continue to occur in the following year after the utility has adequate time to gather the data, verify it, and produce it in a format consistent with other financial data. In this way the data will be complete and reliable. The Commission considered the timing and use of recorded year plus one data in the Rate Case Plan Decision 20-01-002. In that decision, as is reflected in the schedule of this proceeding, the Commission decided that the production of such data "should be considered a standard milestone in every energy GRC."[104]

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102 See *Administrative Law Judge's Ruling Modifying The Procedural Schedule And Partly Denying Sempra Utilities' Joint Motion To Amend The Assigned Commissioner's Scoping Memorandum And Ruling*, A.22-05-015, et al., (Dec. 6, 2022), p. 3, <https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=499629332> (as of Dec. 7, 2022).

103 Cal Advocates Opening Brief, p. 27.

104 D.20-01-002, p. 62.

Cal Advocates' request for a rolling production of partial recorded data, if approved, would lead to continued confusing use of such partial year data as it has in this proceeding. The Commission has recognized this:

> While we agree with TURN that actual data is more accurate than forecasts or estimates, we agree with SoCalGas that it is generally not feasible or prudent to continue to update forecasts to reflect actual data during the pendency of the GRC proceeding. The GRC proceeding is comprised of a multitude of forecasts based on an even greater amount of historical data. But because the GRC proceeding extends over a considerable period of time, newer and more recent data becomes available while the proceeding is pending. However, in order to be able to conclude the proceeding, it is reasonable and prudent for the Commission to stop considering updated information at some point in time. Otherwise, the proceeding may be subjected to continuously review and consider constant updates leading to inconsistencies if only certain forecasts or information were to be updated.[105]

PG&E should not be required to continuously update its recorded year data in any GRC proceeding. Instead, the Commission should continue to establish a "milestone" for the production of the base year + 1 recorded data in the Scoping Memo for the 2027 GRC in March of the year following the GRC application submission as it did in this GRC.

1.5.3 The Commission Should Disapprove Of Cal Advocates Inconsistent Use Of The 2021 Recorded Data

Cal Advocates argues that it can use PG&E's 2021 partial recorded year data inconsistently.[106] It uses it inconsistently in two ways: (1) use of preliminary partial year data plus its own forecast for the remaining months of 2021; and (2) cherry picking the programs for which it requests to true up the 2021 forecast to 2021 recorded.

The Commission has established standards for use of recorded data that Cal Advocates use of partial year recorded data does not meet. In Decision 08-07-045, the Commission indicated that use of base year plus one data is not prohibited by the Rate Case Plan decision if "*the recorded data is in a format 'compatible with the other years of recorded data in order to*

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105 D.19-09-051, p. 612.

106 Cal Advocates Opening Brief, p. 28.

derive trends and forecasts."[107] It rejected the use of such data that "was not in a format compatible with" the base year recorded data.[108] The recorded year data must be "in a format consistent with the historical data," to insure data compatibility."[109] The Commission has repeatedly confirmed that the utilities' base year + 1 data needs to be in a compatible format to be usable.[110]

Cal Advocates should not be able to use partial year recorded data and a partial year forecast that it created. As an example, for its capital forecast for PSPS, instead of using a full year of recorded data, "Cal Advocates derived its recommendation by annualizing the first 10 months of PG&E's recorded capital spending for PSPS."[111] For another area of work, Overhead and Underground Asset Management, it states (incorrectly since PG&E did provide a full year of recorded 2021 data in March 2022):

> Estimating PG&E's 2021 pace of work requires several adjustments. First, PG&E provided the year-to-date spending through November 2021, rather than through the entirety of 2021. Cal Advocates assumes that PG&E's pace of work in December 2021 was proportional to the pace for the first 11 months of the year, and so estimates 2021 total capital expenditures by multiplying the year-to-date November 2021 capital expenditures by 12 divided by 11.[112]

Cal Advocates claims that it did not have sufficient time to use PG&E's actual 2021 recorded data and, in some cases, "extrapolate[ed] or annualize[ed]" the partial year data provided in discovery responses.[113] Nowhere does it explain why having access to the data for

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107 D.13-05-010, p. 19 (emphasis added).

108 D.08-07-046, p. 9.

109 D.13-05-010, p. 17.

110 D.13-05-010, p. 19, stating that, before base year + 1 data can be used in a GRC ("the Commission needs to ensure that the recorded data is in a format 'compatible with the other years of recorded data in order to derive trends and forecasts.'") (quoting D.08-07-046 at 9).

111 Cal Advocates Opening Brief, p. 152.

112 Cal Advocates Opening Brief, pp. 187-188; see also p. 189, fn. 823 for examples of how Cal Advocates' failure to use the actual full 2021 recorded cost data results in inconsistent recommendations for multiple electric programs.

113 Cal Advocates Opening Brief, pp. 188-189.

96 days before its testimony was due was inadequate.

Cal Advocates derivation of PG&E's recorded data is not in a format consistent with the data PG&E presented. Further, as Cal Advocates had the full 2021 recorded data for more than three months before its testimony was due, there is no reason to substitute Cal Advocates' estimates of the recorded year data in place of the end of year actual recorded data PG&E produced in March 2022. Further, for some programs, Cal Advocates did in fact use the full year recorded data, indicating that the three months was sufficient.[114]

The Commission should disapprove party proposals to selectively use the 2021 recorded data only where it is lower than PG&E's 2021 forecast. As discussed in PG&E's Opening Brief, this would distort the results and would lead to an unfair result. The Commission has acknowledged this:

> As such, we find that selectively updating only certain data or in this case applying 2017 recorded costs in some instances but not in others may lead to inconsistent results. *This is because not all data that was submitted with the application is being updated. For example, updating select data to 2017 recorded costs in one area which results in a lower value than the 2017 forecast would be inconsistent if another update in a different area would result in a higher value than the forecast but was not applied.*
>
> We do however recognize that there are instances where it is prudent, necessary, and reasonable to apply updated data in select areas and we exercise our discretion in doing so in appropriate cases. But for this GRC, based on the explanation above, we will generally not apply select updating of data if the sole reason for doing so is simply to update data without any explanation why the updated data should be applied. In this case, we find it more appropriate to apply the 2017 forecasts for all the capital projects.[115]

The Commission should determine in this proceeding whether to consistently use the recorded or forecast capital for 2021.[116] PG&E does not oppose either result as long as the

114 See e.g. CALPA-03, p. 17, lines 7-9 (citing 2021 recorded costs for Gas R&D),CALPA-07 p. 19, lines 5-6. (citing 2021 recorded costs for Sectionalizing Devices).

115 D.19-09-051, p. 60 (emphasis added).

116 The Commission has used the base year + one recorded year data in some GRC decisions in this situation on agreement of the parties. *See, e.g.*, D.19-09-025, p. 243 (citing PG&E agreement to use base year + one recorded data for capital true up); D.20-12-005, p. 92.

result is applied consistently throughout the proceeding. The Commission should decline, however, Cal Advocates' proposal to selectively use the recorded data.

1.6 Other General Issues

Cal Advocates raises for the first time in its Opening Brief an issue that the Commission previously addressed in a Rate Case Plan proceeding. Cal Advocates correctly indicates that in January 2020, the Commission considered and rejected 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."[117] Despite this, Cal Advocates requests that the Commission order PG&E to prepare a new proposal for the utilities to use in GRCs with a "common accounting format for recording forecast costs in GRCs by December 31, 2024."[118] It also requests that PG&E present this proposal at a public workshop that it co-hosts with Energy Division.

Cal Advocates neglects to mention that there was already a Rate Case Plan workshop to discuss the issue of whether the utilities should have a common accounting system in October 2020, following the Commission's January 2020 RCP decision, and that none of the other participants, including TURN, thought that the utilities' unique accounting systems created a problem in their respective GRCs.[119] According to the workshop report, "TURN noted that the issue of standardizing the order of testimony chapters did not originate with TURN and it finds it helpful when each IOU maintains a similar structure to its prior GRC for comparison

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117 Cal Advocates Opening Brief, p. 29, citing D.20-01-002.

118 Cal Advocates Opening Brief, p. 28.

119 Rate Case Plan (Decision 20-01-002) Workshop #2 General Rate Case Filing Standardization (Nov. 6, 2020); see also General Rate Case Plan Workshop #2 Report, GRC Standardization, pp. 10-11. The Workshop # 2 Report (p. 6) indicates that Cal Advocates representatives attended the workshop. Included as Appendix B to the Workshop #2 report are written post-workshop comments submitted by TURN and by the Joint IOUs. Cal Advocates did not submit written comments.

purposes. TURN is not proposing any changes to the status quo."[120] Cal Advocates' request for an additional workshop should be denied; further exploration of this topic would not be useful or productive. In any event, this is not an issue to be resolved in PG&E's GRC.

Cal Advocates concludes: "In sum, PG&E should not be allowed to continue to deviate from the Commission's directive to develop a consistent and common accounting system."[121] To be clear, the alleged directive Cal Advocates cites ***does not exist***. A workshop was already held on this topic, fulfilling the directive in D.20-12-005, and neither of the parties who submitted comments on the workshop, TURN and the utilities, supported changes to the status quo. Cal Advocates' complaints that PG&E developed and presented its GRC based its own accounting system should be disregarded.[122]

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120 General Rate Case Plan Workshop #2 Report, GRC Standardization, p. 11.

121 Cal Advocates Opening Brief, p. 30.

122 Cal Advocates Opening Brief, p. 29.

2. RISK MANAGEMENT, SAFETY, OPERATING RHYTHM AND CLIMATE (EXHIBIT PG&E-02)

2.1 Enterprise Risk Management

Parties' Opening Briefs take issue with a number of aspects of PG&E's enterprise risk management. Most of parties' arguments are fully addressed in PG&E's Opening Brief. To the extent they are not, PG&E discusses them below.

PG&E responds to: (1) Cal Advocates' general criticisms about PG&E's Enterprise Risk Management Organization; (2) issues related to how PG&E complied with Commission requirements to integrate RAMP into the GRC; (3) considerations related to risk spend efficiency (RSE) values; (4) TURN's proposal to convert RSEs into benefit-cost ratios; (5) issues regarding PG&E's Multi-Attribute Variable Framework (MAVF); and (6) Cal Advocates' recommendation related to calculating RSEs for all Maintenance Activity Type codes.

2.1.1 Enterprise Risk Management And Policy

2.1.1.1 Cal Advocates' Claim That PG&E Has Not Adequately Explained What The EORM Organization Does Is Incorrect

Cal Advocates makes several criticisms of the EORM organization, none of which have any merit. First, Cal Advocates claims that "[PG&E] does not say what the EORM program is but rather what it supports, making it difficult to [see] how the program differs from existing duties of the employees."[123] This is incorrect. PG&E did not discuss the structure of the EORM organization in the Risk Management, Safety, Operating Rhythm and Climate exhibits of its prepared and rebuttal testimony because those details were provided in the Shared Services exhibit chapter where the forecast for EORM is discussed.[124] The EORM chapter of the Shared Services testimony describes the four departments that make up EORM, including what they do and how many employees they have.[125]

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123 Cal Advocates Opening Brief, p. 30.

124 PG&E-07, Ch. 11 (Enterprise and Operational Risk Management).

125 PG&E-07, p. 11-3, line 13 to p 11-7, line 7.

Second, Cal Advocates claims that "the EORM is devoid of substance. With or without EORM, PG&E must be able to explain how it incorporates the RAMP Report into its GRCs."[126] As described in both the Risk Management testimony and Shared Services testimony, EORM is the organization that allows PG&E to generate the risk management content for the RAMP Report and ultimately integrates it into the GRC and other regulatory filings such as the WMP. As to how the RAMP Report is incorporated into the GRC, this issue is addressed in our Opening Brief in Section 2.1.2.

Third, Cal Advocates claims that PG&E used the terms EORM and Risk Based Portfolio Prioritization Framework (RBPPF) interchangeably.[127] We believe that our testimony clearly distinguished between the two terms. EORM is the organization that performs PG&E's enterprise risk modeling while the RBPPF is the process by which PG&E's management prioritizes work, in part based on risk models created and administered by EORM and line of business risk organizations.[128]

Finally, Cal Advocates raises issues regarding the connection between EORM and safety, as well as issues related to the NorthStar report in Section 2.1.1 of its Opening Brief. Because these are safety related issues, we have addressed them in Section 2.4 below.

2.1.2 Integrating RAMP Into The GRC

2.1.2.1 PG&E's Description Of PSPS Consequences Complies With RAMP

On June 3, 2021, the Commission ruled on a joint motion filed by Cal Advocates and the FEITA Bureau of Excellence (the Joint Motion) requesting that PG&E be required to analyze the full safety, health and financial consequences of PSPS on its customers. The Commission denied

126 Cal Advocates Opening Brief, p. 31.

127 Cal Advocates Opening Brief, p. 31.

128 PG&E-02, p. 1-10, lines 15-20 ("PG&E continues working through this transition period and is developing new procedures for prioritizing its work on a risk-informed basis. [] The RBPPF applies to all lines of business and will ultimately be used to establish a consistent and complete approach to categorizing and prioritizing work.").

the Joint Motion but found it appropriate for PG&E to provide testimony in this GRC concerning its updated risk analysis of the estimated consequences of initiating PSPS events, and that the testimony must contain analysis and discussion of the consequences of PSPS for customers and how PG&E analyzes those consequences.[129] PG&E's testimony includes a narrative description of how it estimates the frequency, scope, and duration of PSPS events, and the safety, reliability, and financial consequences of those events.[130] This description highlighted changes in PG&E's methodology since the 2020 RAMP.[131] PG&E also provided its risk modelling workpapers for PSPS consequences modelling.[132]

Cal Advocates claims that PG&E's showing is insufficient, and does not comply with RAMP, because it only includes a narrative discussion of PG&E's PSPS consequence methodology "without any technical analysis or calculations demonstrating how conclusions were reached … ."[133] Cal Advocates recommends that the Commission require PG&E to host a series of Technical Working Group meetings to "work with interested parties on a set of metrics that serve as a measure and/or proxy for societal and customer impacts due to the utility's execution of PSPS."[134] Cal Advocates also recommends that, coming out of these meetings, within one year of the decision on this GRC, PG&E be required to submit "… a proposed set of metrics as a result of consensus among parties" and "a summary of why these proposed metrics are sufficient for analyzing the true extent of customer and societal impacts of PSPS … ."[135]

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129 PG&E-04, p. 3-34, lines 5-16.

130 PG&E-04, p. 3-34, line 23 to p. 3-37, line 2.

131 See, e.g., PG&E-04, p. 3-35, line 21 to p. 3-36, line 17 (describing changes in how PG&E evaluated PSPS safety consequences in the 2020 RAMP and 2023 GRC).

132 See, PG&E-17, p. 3-24, fn. 72.

133 Cal Advocates Opening Brief, p. 38.

134 Cal Advocates Opening Brief, p. 38.

135 Cal Advocates Opening Brief, p. 38.

The Commission should not adopt Cal Advocates' recommendations. PG&E's narrative description of its methodology for calculating PSPS consequences and its risk modelling workpapers are sufficient to comply with the RAMP and the Commission's ruling on the Joint Motion. Cal Advocates' approach and its recommendation for Technical Working Group meetings to create metrics that "are sufficient for analysis the true extent of customer and societal impacts of PSPS", is simply an attempt to obtain the relief that Cal Advocates was unable to obtain in the Joint Motion. PG&E will continue to refine its modelling of PSPS consequences and will report on any changes in its 2024 RAMP. Moreover, to the extent the Commission believes the working group described by Cal Advocates would be helpful, it would be more appropriate for the Commission staff to lead this working group rather than PG&E.

2.1.2.2 AARP's Claim That The RAMP Process Is Deficient Should Be Addressed In A RAMP Proceeding Or The RDF OII, Not The GRC

AARP's Opening Brief outlines what it believes are several deficiencies in the RAMP process – including that RSEs do not indicate whether a mitigation delivers more benefits than its costs – and recommends that the Commission avoid relying on the RAMP or S-MAP approach in this proceeding.[136] PG&E has made its risk showing in compliance with the S-MAP Settlement Agreement. AARP is not a signatory to the S-MAP Settlement Agreement and did not participate in PG&E's 2020 RAMP process. If AARP thinks that the RAMP process needs improvement, it should participate in PG&E's (and other IOUs) RAMP proceedings or the Risk Based Decision Making Framework (RDF) OII going forward. Those are the appropriate venues in which to raise these concerns.

2.1.2.3 PG&E Has Complied With The Commission's Risk-Based Decision-Making Framework Requirements

In the Safety Policy and Strategy section of its Opening Brief, Cal Advocates states that, "[t]he Commission should end PG&E's overuse of safety rhetoric by requiring that PG&E supports its proposals for risk spending with probabilistic risk assessment models and only

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136 AARP Opening Brief, pp. 12-14.

approve safety related spending that are founded upon a risk-informed decision making framework."[137] As an example of how the Commission should implement this recommendation, Cal Advocates suggests that the Commission require PG&E to target only the highest risk miles for its system hardening program.[138]

Contrary to Cal Advocates' assertions, PG&E's proposals for risk spending are supported by risk assessment models and its forecasts are supported by a risk-informed decision making framework. The CPUC's risk-based decision-making framework starts with the Safety Model Assessment Proceedings (S-MAP) that establishes a framework to assess safety risks and identify mitigation options. The next element in the risk management framework is the Risk Assessment and Mitigation Phase (RAMP). PG&E is required to file a RAMP application including a RAMP Report describing: its risk assessment and modeling process using the S-MAP framework; the risk modeling outcomes; and the options to mitigate its risks.[139] PG&E filed its 2020 RAMP Report on June 30, 2020, and it was closed by the Commission on March 17, 2022.[140] The Commission found that PG&E's TY2023 GRC included testimony and workpapers containing evaluation and analysis of its top safety risks, cross-cutting factors, and other safety risks as well as proposed mitigations of such risks. PG&E submitted a roadmap identifying where in its TY2023 GRC testimony and workpapers each risk and mitigation appears. There were no issues of material fact in contention.[141] The proposed spending for risk mitigation programs and activities are to be reviewed in PG&E's TY2023 GRC.[142]

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137 Cal Advocates Opening Brief, p. 41.

138 Cal Advocates Opening Brief, p. 41.

139 PG&E-02, p. 1-3, line 23 to p. 1-4, line 13.

140 D.22-03-008.

141 D.22-03-008, p. 13, Findings of Fact (FOF) 9, 10 and 12.

142 D.22-03-008, FOF 11.

Cal Advocates participated in PG&E's RAMP proceeding and has been actively involved in the TY2023 GRC. For Cal Advocates to now argue that "[t]he Commission should [require PG&E to support] its proposals for risk spending with probabilistic risk assessment models and only approve safety related spending that are founded upon a risk-informed decision-making framework"[143] is an attempt to discredit the work PG&E, Cal Advocates, the Commission and other parties have been doing since June 2020 to develop and evaluate PG&E's risk-informed GRC proposals. The Commission has already found that PG&E proposals for risk spending are supported by risk assessment models and adhere to the requirements of the CPUC risk-informed decision-making framework.

As an example of how the Commission should implement this recommendation, Cal Advocates suggests that the Commission require PG&E to target only the highest-risk miles for its system hardening program.[144] As discussed in Section 4.2.2.2 of this Reply Brief, Cal Advocates recommendation for prioritization targets is duplicative and unnecessary. PG&E provides detailed information about how it prioritizes its system hardening program to the Office of Energy Infrastructure Safety ("OEIS" or "Energy Safety") in its Wildfire Mitigation Plan (WMP). OEIS carefully analyzes PG&E's proposals and ultimately determines if PG&E has provided sufficient information about the program and program prioritization. In the 2022 WMP PG&E stated that it will address the top 20 percent riskiest areas of the HFTD based on risk model output. This includes more than 90 percent of undergrounding work being completed in the top-risk areas, prior to adding PSPS, Public Safety Specialist-identified, and fire rebuild projects. In total, PG&E estimated 88 percent of its undergrounding projects to be within the top 20 percent risk-ranked circuit segments from 2022 to 2026.[145] PG&E should not be held to

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143 Cal Advocates Opening Brief, p. 41.

144 Cal Advocates Opening Brief, p. 41.

145 2022 Wildfire Mitigation Plan, OEIS Docket #2022-WMP, Final Decision on PG&E's 2022 Wildfire Mitigation Plan Update (Nov. 10, 2022), p. 77.

different commitments in multiple proceedings and believes that adhering to the commitments made in the WMP and approved by OEIS is a reasonable approach.

PG&E has complied with the requirements related to supporting spending proposals with probabilistic risk assessment models and proposing safety related spending that is founded upon a risk-informed decision-making framework. PG&E should not be subject to any additional requirements such as those proposed by Cal Advocates.

2.2 Risk Modeling Issues

PG&E discusses risk modelling issues, including RSEs, Cost-Benefit analysis, and MAVF implementation, in Section 2.3 below.

2.3 Risk Spend Efficiency

2.3.1 PG&E Does Not Object To The Commission Considering RSEs, But RSEs Should Not Be The Sole Factor Considered In Funding Decisions

TURN's lengthy discussion of RSEs in its Opening Brief is based on the premise that PG&E does not think that the Commission should consider RSEs as a part of its assessment of whether to fund programs.[146] But that is not PG&E's position. We have explained that our RSE estimates are inherently uncertain due to the nature of the data used in the modelling, the various assumptions (e.g., of mitigation effectiveness) used, the uncertain extent to which the models capture all the relevant features of the system, and the characteristics of the models themselves.[147] Given this uncertainty, RSEs should not be used mechanically or prescriptively as the sole factor in funding decisions.[148] As Sumeet Singh, PG&E's Chief Risk Officer, explained at hearings: "I think our position continues to be that the use of RSEs is one input, which is again, consistent with the S-MAP and should not be used as a sole determining factor as

146 See, e.g., TURN Amended Opening Brief, pp. 56-76, Section 2.3.2.

147 PG&E-15, p. 1-36, line 3 to p. 1-39, line 22.

148 See, e.g., PG&E-15, p. 1-39, lines 3-4 (Q: How does uncertainty in RSEs inform PG&E's use of RSEs? A: RSEs are best used to inform decisions alongside other considerations … .).

[a] threshold of what should get funded and what should not. It is absolutely inappropriate for that purpose."[149]

TURN's cites part of a sentence in Mr. Singh's rebuttal testimony – "PG&E does not think it is appropriate to … recommend funding reduction in a GRC based on a risk evaluation process that is still being developed" – for the proposition that PG&E has abandoned RSEs.[150] But the full quote provides important context: "PG&E does not think it is appropriate to *implement prescriptive solutions* or recommend funding reductions in a GRC based on a risk evaluation process that is still being developed."[151] And other parts of Mr. Singh's rebuttal testimony makes clear that PG&E is not opposed to the Commission's consideration of RSEs, merely to TURN's proposed prescriptive use of RSEs as the sole basis for funding decisions:

> … TURN's suggestion that decisions on program funding can be based primarily on whether a program's RSE is above or below a particular value is misguided and should be rejected. TURN's proposal assumes that RSEs are stable, are estimated with precision, and can be used to determine the value of a risk mitigation program in an absolute sense. The reality is that estimated RSEs are contingent on model formulation and inputs that are inherently imprecise. While PG&E believes that MAVF models and RSEs do provide some insight into the relative magnitude of risks and the relative cost-effectiveness of proposed programs to mitigate those risks, PG&E does not believe that MAVF model development or RSEs have reached the level of maturity where they can reasonably be used in the manner that TURN proposes.[152]

TURN similarly quotes several instances in PG&E's Gas rebuttal testimony where a witness discussing a particular program stated that the RAMP modelling process "is not sufficiently mature to support funding decisions."[153] But PG&E's Gas Risk witness Vincent Tanguy provided a more detailed description of PG&E's approach to RSEs: "… the current

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149 Tr. Vol. 4, 683:23 to 684:1, PG&E/Singh.

150 TURN Amended Opening Brief, p. 57.

151 PG&E-15, p. 1-4, lines 8-10 (emphasis added).

152 PG&E-15, p. 1-10, line 27 to p. 1-11, line 9. PG&E explains at length why its RSE estimates are inherently uncertain in rebuttal testimony. *Id*., at p. 1-36, line 3 to p. 1-39, line 22.

153 TURN Amended Opening Brief, p. 72 and fn. 206.

RAMP modeling and methodology are not sufficiently mature to support funding decisions *based exclusively on RSE results*."[154] This statement is fully consistent with Mr. Singh's statements discussed above.

Despite TURN's protestations, PG&E's position on RSEs is unremarkable, and fully consistent with the S-MAP Settlement Agreement, which states in the Appendix, Row 26 that "[i]n the RAMP and GRC, the utility will clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations. The utility is not bound to select its mitigation strategy based solely on RSE ranking."[155] TURN attempts to minimize this language by arguing that Row 26 creates a "default" requirement to use RSEs for mitigation strategies and that the consideration of other factors is an "exception."[156] Notably, TURN's Opening Brief does not include the entire text of Row 26:

> The utility's RAMP filing will provide a ranking of all RAMP mitigations by RSE.
>
> In the GRC, the utility will provide a ranking of mitigations by RSE, as follows: (1) For mitigations addressed in the RAMP, the utility will use risk reduction estimates, including any updates, and updated costs to calculate RSE and explain any differences from its RAMP filing; (2) For mitigations that require Step 3 analysis under and consistent with Row 28, the utility will include the RSE, calculated in accordance with Step 3, in the ranking of mitigations by RSE.
>
> In the RAMP and GRC, the utility will clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations. The utility is not bound to select its mitigation strategy based solely on RSE ranking.
>
> Mitigation selection can be influenced by other factors including funding, labor resources, technology, planning and construction lead time, compliance requirements, and operational and execution considerations. In the GRC, the utility will explain whether and how any such factors affected the utility's mitigation selections.

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154 PG&E-16-E, p. 3-7, lines 11-12 (emphasis added).

155 TURN-116, S-MAP Settlement Agreement Adopted in D.18-12-014, p. A-14, Global Item No. 26.

156 TURN Amended Opening Brief, pp. 70-71.

Contrary to TURN's assertion, Row 26 does not make RSEs the default selection criteria and other factors exceptions to those criteria. Indeed, the terms "default" and "exception" cannot be found in Row 26. What Row 26 does make clear is that in the GRC, the utility can consider a number of factors including RSEs, funding, operational issues, and compliance issues. The language also makes clear that RSEs are not the "sole" factor and that the utilities are not bound by RSEs. The key concept in Row 26 is not a requirement as to default factors and exceptions, as TURN seems to imply, but rather that the utility clearly and transparently explain the mitigations it has chosen and how and why a variety of factors affected that selection. This is exactly what we did in our Prepared Testimony where we provided the RSE, described other factors, and explained what mitigations we had selected and why we made that selection.

As SoCalGas, SCE, and SDG&E (i.e., Joint IOUs) note in their Opening Brief:

> [T]he TURN witness is attempting to usurp Commission and utility management decision-making and judgment by insisting that the RSE must be the blanket determinant. This is not risk-informed decision-making. It is risk-distorted decision-making.[] Applicable Commission precedent has established that RSE calculations help inform decision-making, but do not serve as the singular basis for determining whether to authorize cost recovery in a GRC.[157]

The Joint IOUs' Opening Brief discusses that applicable precedent at length.[158]

TURN's most significant RSE-based recommendation is to significantly reduce funding for certain Gas Distribution and Transmission programs based solely on their low RSEs. As discussed in greater detail in Section 3 of PG&E's Opening and Reply Briefs, PG&E has provided ample justification for its forecasts for all of its proposed Gas organization programs.

2.3.2 The Commission Should Not Adopt TURN's Flawed Proposal To Convert RSEs Into Benefit-Cost Ratios

TURN argues in its Opening Brief that RSEs can and should be expressed as benefit-cost ratios and that the benefit-cost ratio for any mitigation equals the RSE value calculated by PG&E

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157 Joint IOUs Opening Brief, p. 4.

158 Joint IOUs Opening Brief, pp. 4-7.

divided by five.[159] TURN's calculation is based on two flawed assumptions – that PG&E's use of a non-linear scaling function for the safety and financial attributes of its MAVF is improper and that the average value of scaled unit of risk reduction in PG&E's MAVF is $200 million.[160] PG&E's rebuttal testimony and Opening Brief demonstrate why use of a non-linear scaling function is both permitted by the S-MAP Settlement Agreement and reasonable as a way to capture the importance of considering tail risk and the premium PG&E places on identifying and mitigating potentially catastrophic risk events, and why TURN's assumption of a $200 million average scaled risk unit of risk is not accurate.[161] PG&E will not repeat that discussion here. TURN's flawed assumptions invalidate its benefit-cost approach.

Another reason to reject TURN's approach is that the idea of converting an RSE into a benefit-cost ratio is inconsistent with the S-MAP Settlement Agreement in its current form. PG&E believes that the appropriate place to consider such a significant change to the S-MAP process is the Risk-Based Decision-Making Framework OIR (RDF OIR).[162] SoCalGas, SCE, and SDG&E agree, noting that "[an issue] of such statewide importance and safety consequence are more properly addressed in a broader rulemaking (where the interests of all stakeholders can be effectively and efficiently considered) rather than in a utility-specific ratemaking proceeding."[163]

PG&E noted in its Opening Brief that on August 8, 2022, the Commission issued a ruling in the RDF OIR providing for comment on a Staff Proposal from the Commission's Safety

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159 TURN Amended Opening Brief, p. 76.

160 TURN Amended Opening Brief, p. 76 ($200 million value of scaled risk unit); p. 78 (non-linear scaling function not rational).

161 PG&E-15, p. 1-7, line 1 to p. 19, line 15; p. 1-22, line 5 to p. 1-28, line 30 (reasonableness of PG&E's use of a non-linear scaling function); p. 1-18, line 9 to p. 1-20, line 18 (TURN's use of a $200 million scaled risk unit is incorrect). See also, PG&E Opening Brief, pp. 31-33.

162 See fn. 70.

163 Joint IOUs Opening Brief, p. 3.

Policy Division (SPD) recommending significant changes to the MAVF and RSE methodology used in the S-MAP including moving to a benefit-cost approach.[164] SPD staff recognized that moving to a benefit-cost approach will require modifications to the existing S-MAP framework and the Staff Proposal notes that "Staff do not expect these recommendation will be implemented retroactively into already filed RAMP applications or General Rate Cases."[165] Instead, SPD staff recommended that its recommendations be required beginning with PG&E's 2024 RAMP.[166]

On November 3, 2022, the Commission issued a proposed *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*. The Proposed Decision considered comments from parties, including TURN, to the SPD Staff Proposal.[167] The Proposed Decision adopts the Staff Proposal and directs the IOUs "to implement the Cost-Benefit Approach in the RDF by implementing a dollar valuation of Attributes rather than the MAVF approach."[168] IOUs are directed to implement this new approach "in their next respective GRC cycles, beginning with PG&E's 2024 RAMP application."[169] The Proposed Decision notes the limited value of RSEs generated by the MAVF approach:

> We agree with Staff that utility presentation of unitless Risk Scores, as required in the MAVF approach, has complicated interpretation of the IOUs' RAMP filings and thus have not supported transparency. We concur with Staff that the RSE values produced by the MAVF approach have had limited utility.[170]

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164 PG&E Opening Brief, p. 28 (citing PG&E-29).

165 PG&E-29, Attachment A, Staff Proposal on Ph. II R.20-07-013 (SPD Proposal), p. v.

166 PG&E-29, Attachment A, SPD Proposal, p. v.

167 R.20-07-013, *Ph. II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in D.18-12-014 and Directing Environmental and Social Justice Pilots* (Nov. 3, 2022) ("Proposed Decision re RDF Modifications" or "Proposed Decision"), p. 9.

168 Proposed Decision re RDF Modifications, p. 22.

169 Proposed Decision re RDF Modifications, p. 22. *See also id*., pp. 56-57, OP 2.

170 Proposed Decision re RDF Modification, p. 23. *See also id*., p. 49, FOFs 2 and 3.

In the Proposed Decision, the Commission disagreed with party comments regarding the need to "test drive" the Cost-Benefit Approach before adopting it.[171] Instead, the Commission directed PG&E to conduct at least one workshop demonstrating implementation of the Cost-Benefit Approach at least 30 days prior to filing its 2024 RAMP.[172] The Commission noted the need "to further explore the application of Risk Attitude, Risk Tolerance, uncertainty, and tail risks" and authorized the continuation of the Technical Working Group established by D.21-11-009 to address those topics.[173]

Although the SPD Staff Report and the Proposed Decision clearly state that the new Cost-Benefit Approach should not be applied retroactively to ongoing proceedings and should first be utilized in PG&E's 2024 RAMP, TURN still argues that its benefit-cost approach should be adopted not just in this GRC, but also in Sempra's pending GRC and SCE's upcoming GRC.[174] TURN argues that the Commission has consequential decisions to make and should not delay in implementing a benefit-cost approach, which TURN has provided.[175] But, as PG&E has shown, there are aspects of TURN's approach that at worst are wrong and at best require further refinement and vetting by all parties to the S-MAP Settlement Agreement. Adopting TURN's proposal to retroactively apply it in this GRC would fly in the face of Commission guidance in the SPD Report and Proposed Decision and subject PG&E (and Sempra and SDG&E) to an untested analysis that was not contemplated in the S-MAP Settlement Agreement.

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171 Proposed Decision re RDF Modification, p. 25.

172 Proposed Decision re RDF Modification, p. 26. *See also id.*, p. 58, OP 3.

173 Proposed Decision re RDF Modification, p. 26. *See also id.*, p. 58, OP 4.

174 TURN Amended Opening Brief, pp. 82-84, Section 2.3.3.3.

175 TURN Amended Opening Brief, p. 83.

2.3.3 PG&E's MAVF Implementation Is Reasonable

TURN argues two aspects of PG&E's MAVF are flawed and should be corrected.[176] First, TURN claims that PG&E's use of non-linear scaling functions for the Financial and Safety attributes of the MAVF is improper.[177] PG&E's rebuttal testimony and Opening Brief show that PG&E's use of non-linear scaling functions is both permitted by the S-MAP Settlement Agreement and appropriate to model PG&E's aversion to tail risk/catastrophic risk.[178] PG&E will not repeat that material here. PG&E notes that both the SPD Staff Report and Proposed Decision in the RDF OIR discussed above propose substantial changes to the existing S-MAP Settlement Agreement, but both would continue to allow IOUs to use a non-linear scaling function to capture risk aversion, as PG&E has done in this GRC.[179] Second, TURN argues that PG&E's weighting and scaling for its MAVF result in an excessive and unreasonable statistical value of life.[180] PG&E's rebuttal testimony and Opening Brief also fully address this issue.[181]

TURN makes two proposals with respect to calculating MAVF and RSE values:

- For purposes of the Commission's analysis of the cost-effectiveness of PG&E's proposals <u>in this case</u>, 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

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176 TURN Amended Opening Brief, p. 84.

177 TURN Amended Opening Brief, pp. 85-86, Section 2.3.4.1.

178 PG&E-15, p. 1-22, line 5 to p. 1-30, line 30; PG&E Opening Brief, pp. 31-33.

179 PG&E Opening Brief, 32-33 (discussing SPD Staff Report). Appendix B of the RDF OIR Proposed Decision is a redline of the S-MAP Settlement Agreement against a new "Risk-Based Decision-Making Framework" which carries over many aspects of the S-MAP Settlement Agreement. "Cost Benefit Approach Principle 6 – Risk Adjusted Levels" (formerly "MAVF Principle 5 – Scaled Units") states: "The Risk Attitude Function can be linear or non-linear. For example, the Risk Attitude Function is linear to express a risk-neutral attitude if avoiding a given change in the Monetized Attribute Level does not depend on the Attribute Level. <u>Alternatively, the Risk Attitude Function is non-linear to express a risk-averse or risk-seeking attitude if avoiding a given change in the Monetized Attribute Level differs by Attribute Level</u>." RDF OIR Proposed Decision, Appendix B, p. A-8 (emphasis added).

180 TURN Amended Opening Brief, pp. 86-87, Section 3.2.4.3.

181 PG&E-15, p. 1-31, line 1 to p. 1-35, line 2; PG&E Opening Brief, p. 33.

which TURN supports its recommendations with RSE analysis have low RSEs and B/C ratios.[182]

- 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.[183]

The Commission should reject TURN's proposal for this GRC to use MAVFs or RSEs to calculate Benefit-Cost ratios for the reasons discussed above in Section 2.3.2. To the extent the Commission chooses to consider RSEs, it should use the RSE values calculated by PG&E. TURN's modifications to PG&E's MAVF, particularly its refusal to use non-linear scaling functions even though it is allowed by the S-MAP Settlement Agreement, are not proper and misstate risk preferences.

TURN's going-forward proposal should also be rejected, not least because TURN again incorrectly asserts that PG&E must use a linear scaling function for Safety and Financial Attributes. Moreover, the Commission's Proposed Decision in the RDF OIR sets forth both a framework and a timeline for future modifications to the MAVF and the adoption of a fully vetted Cost-Benefit approach. If the Proposed Decision is adopted, PG&E will be required to present its implementation of the approach outlined in the Proposed Decision at a workshop at least 30 days before filing its 2024 RAMP.[184] It would be both unnecessary and inappropriate to require PG&E to make interim adjustments in the meantime and implementing TURN's proposal could potentially create conflicts with directives from the RDF OIR.

2.3.4 The Commission Should Not Order PG&E To Calculate RSEs For All MAT Codes In Its Next GRC

Cal Advocates' Opening Brief recommends that the Commission "require PG&E to provide more granular RSEs at the individual MAT code program for all future GRC

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182 TURN Amended Opening Brief, p. 91 (emphasis added).

183 TURN Amended Opening Brief, p. 91 (emphasis added).

184 Proposed Decision re RDF Modification, p. 26. *See also id.*, p. 58, OP 3.

applications, rather than at a mitigation or control code level."[185] Cal Advocates' discussion of this recommendation in its Opening Brief is virtually identical to its discussion in prepared testimony.[186] PG&E has already fully responded to Cal Advocates' arguments on this topic in its Opening Brief[187] and will not repeat that material here.

2.3.5 TURN's Analysis Of Operational Failure Is Not Correct

TURN raises the issue of Operational Failure in connection with Electric Distribution wildfire risk and PG&E's undergrounding program. This issue is discussed in Section 4.2.3 below.

2.4 Safety Policy And Strategy

Cal Advocates and MGRA were the only parties to address Safety Policy and Strategy apart from RAMP issues.

Cal Advocates recommends that the Commission "should require PG&E to connect its Enterprise Risk Management (ERM) to the Safety Culture policy and explain how ERM is implementing the Commission's safety culture recommendations" pointing specifically to the NorthStar report.[188] With regard to PG&E's GRC filings, Cal Advocates asserts that "the Commission should require PG&E to explain in full and complete detail how it plans to report how much it spends on electric distribution safety, separate from reliability and integrity expenditures."[189] MGRA's comments focus on its proposed safety policy and strategy factors. PG&E addresses MGRA's and Cal Advocates' recommendation below.

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185 Cal Advocates Opening Brief, p. 191.

186 Compare, CALPA-06, p. 27, line 1 to p. 28, line 7 to Cal Advocates Opening Brief, pp. 190-191.

187 PG&E Opening Brief, pp. 44-45.

188 Cal Advocates Opening Brief, p. 33.

189 Cal Advocates Opening Brief, p. 33.

2.4.1 Response To MGRA's Arguments

MGRA outlines six safety policy and strategy factors in its Opening Brief: (1) PG&E's undergrounding program should be scaled back significantly; (2) PG&E's covered conductor program should be expanded to address high risk circuits; (3) advanced technology programs should as REFCL that can be deployed in conjunction with covered conductor should be accelerated; (4) the Commission should revisit its guidance for PSPS and EPSS; (5) the Commission should develop guidelines for incorporating additional consequences related to wildfires and PSPS into utility risk models; and (6) any future application for an undergrounding program should include a full cost/benefit and alternatives analysis.[190]

MGRA's first three recommendations are related to PG&E's system hardening program. Recommendation 1 is addressed in Section 4.3.1.1 of PG&E's Opening Brief and in Sections 4.3.1.2 and 4.3.1.3 of PG&E's Reply Brief. Recommendation 2 is addressed in Section 4.3.2 of PG&E's Opening and Reply Briefs. PG&E's REFCL forecast, recommendation 3, was uncontested and therefore is not addressed by PG&E in its Opening Brief.

With regard to recommendation 4, PG&E will comply with any guidance from the Commission related to PSPS and EPSS. This is not an issue that needs to be resolved in this GRC.

For recommendation 5, the guidelines that MGRA describes are being discussed by parties in the Risk-Based Decision-Making Framework OIR.[191] PG&E discusses the RDF OIR in Section 2.1.1.2 of its Opening Brief.

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190 MGRA Opening Brief, pp. 45-46.

191 R.20-07-013, *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning* (Jan. 27, 2020) (RDF OIR).

Finally, for recommendation 6, PG&E will comply with any guidance from the Commission related to future applications for an underground program, such as under SB 884. This is not an issue that needs to be resolved in this GRC.

2.4.2 Response To Cal Advocates' Arguments

Cal Advocates' recommendation that the Commission should require PG&E to connect ERM to the Safety Culture policy and explain how ERM is implementing the Commission's safety culture recommendations[192] is premature and is more appropriately considered as part of PG&E's Safety Culture Proceeding (*Order Instituting Investigation on the Commission's Own Motion to Determine Whether PG&E and PG&E Corporation's Organizational Culture and Governance Prioritize Safety*, I.15-08-019 (Sept. 2, 2015) (Safety Culture OII). The issues that Cal Advocates raises are already being considered in the Safety Culture OII, in which both Cal Advocates and PG&E are active participants.

As part of the Safety Culture OII, NorthStar Consulting was retained to assess and report on PG&E's safety culture. NorthStar provided an initial report in 2017. Cal Advocates' recommendation in this proceeding relies heavily on NorthStar's final update to its 2017 report. This update was included as part of the *Administrative Law Judge's Ruling Providing the Final NorthStar Report Update and the Safety Policy Division Staff Report* issued on September 16, 2022, after the portion of the GRC hearings related to risk management were concluded. The final NorthStar report is not in the record and Cal Advocates did not mention any iteration of the NorthStar report in its prepared testimony.[193] PG&E filed comments on the NorthStar update strongly contesting Cal Advocates' interpretation of the NorthStar

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192 Cal Advocates Opening Brief, p. 33.

193 Counsel for Cal Advocates asked PG&E witness Sumeet Singh a few cross-examination questions with reference to excepts from an earlier version of the NorthStar Report but did not develop any of the arguments Cal Advocates is making here. Tr. Vol. 4, 649:4 to 653:22, PG&E/Singh.

recommendations and PG&E's safety culture progress.[194] On November 3, 2022, the Administrative Law Judge in the Safety OII issued a decision extending the statutory deadline to November 23, 2023 to provide the Commission sufficient time to review comments and reply comments on the September 16, 2022 ruling, consider the Commissions' Safety Policy Division Staff Report, and determine the appropriate next steps in the proceeding.[195] The appropriate place to address Cal Advocates' concerns related to the NorthStar report is the proceeding in which that report was commissioned, the Safety Culture OII, not this GRC.[196]

2.5 Planning, Work Prioritization And Financial Issues

2.5.1 Operating Rhythm

Parties did not address this issue in their Opening Briefs.

2.5.2 Deferred Work And Spending Accountability Issues

PG&E's Opening Brief summarizes the requirements of Section 5.2 of the 2020 GRC Settlement "Deferred Work Principles" (Deferred Work Settlement or DWS).[197] The DWS defines "deferred work" as any work proposed in the 2020 GRC or 2019 GT&S rate case where: (1) the work was requested and authorized based on representations that it was needed to provide safe and reliable service; (2) PG&E did not perform all of the authorized and funded work, as

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194 I.15-08-019, Reply Comments of PG&E and PG&E Corporation on Northstar Consulting Group's Final Update and Report (Oct. 21, 2022), pp. 1-7.

195 D.22-11-012, p. 4, FOF 2.

196 Cal Advocates incorrectly claims that PG&E has wholly abandoned the Enterprise Safety Management System (ESMS) or its development. (Cal Advocates Opening Brief, pp. 35-36.) PG&E forecast for this program is included in its Shared Services testimony. (See PG&E-07, p. 1-6, lines 30-33 ("[T]he Company is transitioning to the 2025 Workforce Safety Strategy including continued implementation of HSMS, previously known as the Enterprise Safety Management System (ESMS), which provides governance over the Company's workforce and public safety."))

197 PG&E-02, p. 3-7, lines 11-13.

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.[198]

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

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.[199]

The DWS also requires that PG&E provide at a minimum, a demonstration of how the specific funding request is consistent with six listed principles that were reflected in prior GRC decisions.[200]

In its Opening Testimony, PG&E performed the required deferred work analysis, and explained how its deferred work was consistent with the six principles.[201] No party took issue with PG&E's identified deferred work presented in testimony, or recommended any disallowance based on the identified deferred work.[202] However, in response to PG&E's deferred work testimony, TURN recommended that the DWS requirements be continued in the

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198 PG&E-02, p. 3-7, lines 13-20.

199 PG&E-15, p. 3-2, lines 13-23.

200 PG&E-02, p. 3-8, line 6 to p. 3-13, line 11. Section F.3 sets forth the six principles, and describes how PG&E's reprioritization decisions over the last rate case period are consistent with the principles.

201 PG&E-15, p. 3-3 lines 3-6.

202 TURN recommended disallowances for two of PG&E's 2023 gas operations funding requests that were not identified in PG&E-02, Table 3-1. (PG&E-02, p. 3-14 to p. 3-19.) These are the Los Medanos and Tionesta compressor station projects and are addressed in Sections 3.5.5 and 3.5.6 of this Reply Brief.

next rate case[203] and that PG&E be required to demonstrate that any reprioritization of funds from work meeting the deferred work criteria be supported by RSE scores.[204]

PG&E responded to TURN's recommendations in its Opening Brief.[205] PG&E recommends that the DWS be discontinued because (1) existing Commission decisions and requirements already require PG&E to identify deferred work in rate cases;[206] and (2) extensive annual risk spending accountability reporting (RSAR) requirements that were recently modified to include analysis of spending and variances from authorized spending over the whole GRC cycle.[207] If the DWS is continued, the Commission should reject TURN's proposal to require that reprioritization decisions be supported by RSE scores because RSEs have not reached the level of maturity where they could reasonably be used for reprioritization purposes.[208]

In its Opening Brief,[209] TURN makes numerous further arguments. Although it did not submit testimony on deferred work issues, in its Opening Brief Cal Advocates criticizes PG&E's showing on the consistency of deferred work with the six principles under the DWS.[210] PG&E responds to these issues below.

2.5.2.1 The Deferred Work Settlement Should Be Discontinued

First, TURN claims that the DWS "promotes more efficient operations, which benefits both PG&E and its ratepayers" because, according to TURN, "the DWS requires PG&E's management to be ready to demonstrate that the reprioritized use of the authorized funding was

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203 TURN-19, p. 22, lines 18-19.

204 TURN-19, p. 26, lines 13-15.

205 PG&E Opening Brief, pp. 57-59, Section 2.5.2.2.

206 PG&E Opening Brief, pp. 59-60.

207 PG&E Opening Brief, pp. 60-61.

208 PG&E Opening Brief, pp. 62-63.

209 TURN Amended Opening Brief, p. 92-102, Section 2.5.2.

210 Cal Advocates Opening Brief, pp. 43-44, Section 2.5.2.

reasonable and gave ratepayers good value for their money." [211] However, existing Commission precedent already requires PG&E to explain deferred work. In D.11-05-018, the Commission said, "[w]hile we reaffirm that it is utility management's prerogative and responsibility to provide safe and reliable service by reprioritizing and deferring activities as necessary, the Commission must be assured that the process is reasonable."[212] Moreover, TURN's claim is pure speculation. There is no evidence that the DWS has resulted in more efficient operations or benefits to ratepayers. Existing Commission requirements and oversight, including extensive reporting requirements that require variances from GRC authorized funding to be identified and explained, already provide ample incentives for prudent and efficient management of GRC funding without the need for the DWS to be continued.

Second, TURN claims "the DWS has helped to stabilize the extent to which PG&E is deferring work."[213] In support of this claim, TURN states the following: "PG&E reports total expense underspending at 'less than 0.1% of overall imputed adopted expense,'[214] compared with "less than 1 percent" in the 2020 GRC[215]. . . . . With respect to capital, the 2023 GRC dollar amount of underspending ($239.9 million or 0.6% of overall imputed capital)[216] appears relatively stable compared to the 2020 GRC ($223 million or 2% of authorized.)"[217] PG&E disagrees that any trend can be inferred from these numbers, much less that such a trend can be

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211 TURN Amended Opening Brief, p. 95.

212 D.11-05-018, p. 29.

213 TURN Amended Opening Brief, p. 96.

214 PG&E-02, p. 3-10, lines 3-4.

215 TURN Amended Opening Brief, p. 96, citing PG&E 2020 GRC (A.18-12-009) Ex. PG&E-02, p. 2-11.

216 PG&E-02, p. 3-10, lines 8-9.

217 TURN Amended Opening Brief, p. 96, citing PG&E 2020 GRC (A.18-12-009) Ex. PG&E-02, p. 2-12.

attributed to the DWS. Instead, what these numbers show is that PG&E consistently spends its authorized funding on its safety programs.

Third, TURN continues to recommend deferred work disallowances for two of PG&E's 2023 gas operations funding requests that were not identified by PG&E in its deferred work analysis.[218] These are the Los Medanos and Tionesta gas compressor station projects that are addressed in Sections 3.5.5 and 3.5.6 of PG&E's Opening Brief, and Sections 3.5.5 and 3.5.6 of this Reply Brief. TURN's arguments for these two projects undermine both the intent and the specific wording of the DWS requirements contrary to TURN's claim that "DWS has averted disputes about the principles applicable to deferred and reprioritized work."[219] As explained in Section 3.5.5 below, the claim that the Los Medanos compressor station replacement represents deferred work based on authorized funding <u>two rate cases ago</u> (the 2015 GT&S case) represents a misapplication of DWS requirements; would be inconsistent with how deferred work analysis under the DWS has been performed in all rate cases to date where work expected to be performed in the current rate case cycle is compared to the work authorized <u>for that same rate case cycle</u>;[220] would destabilize the GRC and create uncertainty; and would violate the rate case principle of reasonable (and expected) reprioritization of funding adopted by the Commission. The Los Medanos compressor replacement authorized in the 2015 GT&S case was not performed for valid reasons and the unused funding was reprioritized to other work as shown in the 2019 GT&S case. No party disputed these facts in the 2019 GT&S case. As a result, the Commission did not identify the project as deferred work nor was any funding disallowance adopted in the 2019 GT&S rate case decision. Thus, no basis exists to relitigate this issue or

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218 PG&E-02, p. 3-14 to p. 3-19, Table 3-1.

219 TURN Amended Opening Brief, p. 96.

220 As discussed further in Section 3.5.5 of this Reply Brief, the RSAR requires PG&E to identify and explain variances between imputed units authorized for the current time period (not some prior time period), compared to actual units and funding for the same time period. This approach is consistent with the way in which deferred work is evaluated in the GRC.

change the Commission's conclusion in the 2019 GT&S case and doing so would violate *res judicata* principles.[221] With respect to the Tionesta Compressor station, TURN also misapplies explicit DWS requirements. Deferred work only exists if PG&E does not perform authorized work and seeks funding again for that work in the current rate case. The funded work from the 2019 GT&S case was replacement of the Tionesta compressor station. However, PG&E will no longer replace the compressor but will retire the facility instead. PG&E is therefore not requesting funding for the replacement project in the 2023 GRC and does not continue "to represent that the curtailed work is necessary to provide safe and reliable service," which is the requirement under the DWS for finding deferred work.

Fourth, TURN alleges that PG&E has a "long history of deferred work for the Gas Distribution SCADA program (MAT 4AM), for which PG&E has repeatedly performed less work than authorized on the basis that higher priority work was warranted."[222] This assertion is not accurate and as explained in Section 3.10.5.3 of this Reply Brief, PG&E's past performance is consistent with the goal of completing the GD SCADA Program by 2025.

Fifth, TURN claims that "spending accountability reports, such as the RSAR, . . . are helpful for promoting more accountability in how utilities spend risk reduction funding, but they have no direct correlation to PG&E's requests in the GRC."[223] PG&E disagrees. In D.22-10-002, the Commission adopted additional RSAR reporting requirements that effectively supersede the DWS requirements.[224] As a result, in future RSARs, PG&E will identify variances for GRC-authorized safety and reliability programs and address the "completion status" for the

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221 As discussed further in Section 3.5.5 of this Reply Brief, the Commission has recognized that "[r]es judicata principles are among the most fundamental in our legal system, protecting parties from endless relitigation of the same issues." (D.92058, p. 14.) While Pub. Util. Code, § 1708 gives the Commission the discretion to "rescind, alter or amend any order or decision made by it," this is an "extraordinary remedy." (D.92058, p. 14.)

222 TURN Amended Opening Brief, p. 97.

223 TURN Amended Opening Brief, p. 101.

224 PG&E Opening Brief, pp. 60-61.

reporting year and GRC cycle. These reports will provide the Commission and parties with more than sufficient information to identify and address deferred work from the prior GRC period without PG&E being required to provide a duplicate analysis in the GRC.[225]

2.5.2.2 The Deferred Work Settlement Should Not Be Revised To Require Reprioritization Decisions Be Justified Based On RSE Scores

In its Opening Brief, TURN continues to argue that the DWS language should be modified to require that reprioritization decisions be justified based on RSE scores.[226] If the Commission continues the DWS, PG&E objects to this proposal because RSEs have not reached the level of maturity where they could reasonably be used for reprioritization purposes.[227]

In further support of its proposed modification to the DWS, TURN asserts "RSE analysis, . . . is well suited to supporting PG&E's decisions about whether reprioritization of work is appropriate and how reprioritized funding should be used."[228] As PG&E explains in its Opening Brief, TURN's RSE score and benefit-cost ratio analysis is seriously flawed, inconsistent with Commission precedent, and uses RSE scores for a purpose that was never intended.[229] The Commission's staff has also recognized that RSE "values, intended to assist with Commission decision-making on utility proposed safety mitigations, are poorly understood and offer little guidance in determining the cost-efficiency of proposed investments for the Commission."[230] Until these issues around risk modelling are resolved, and further guidance is

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225 Additionally, PG&E currently files a semi-annual Gas Transmission and Storage Compliance Report that provides information about our transmission pipeline work including all costs recorded to these programs. (D.19-09-025, pp. 11-12, and p. 334, OP 83.) However, reporting on these programs will be merged with RSAR starting in 2023. (D.22-10-002, p. 56, OP 3.)

226 TURN Amended Opening Brief, p. 99.

227 PG&E Opening Brief, p. 62-63.

228 TURN Amended Opening Brief, p. 99.

229 PG&E Opening Brief, pp. 37-39.

230 PG&E Opening Brief, p. 40, citing PG&E-29, Attachment A, SPD Proposal.

provided on how RSE scores should affect reprioritization and funding decisions, it is not appropriate to revise the DWS as TURN suggests.

If the Commission nevertheless determines that the DWS should be modified to require RSEs to be addressed, PG&E recommends alternative language as shown italics below. In its Opening Brief, TURN accepts PG&E's alternative proposed language.[231]

> To the extent that authorized funding for safety related work was used for other purposes, PG&E's showing in support of its forecast for additional funding for the curtailed work shall include a demonstration of the reasonableness of the alternative work, *including a discussion of RSE scores calculated in accordance with Commission requirements*, for the purpose of evaluating the appropriateness of the new funding request.

2.5.2.3 PG&E Addressed The Six Principles Consistent With The Deferred Work Settlement

Cal Advocates claims that PG&E's testimony explaining that its deferred work is consistent with the six principles "are mere conclusions that constitute opinions outside the area of expertise of the PG&E witness who presented them."[232] However, in presenting its deferred work PG&E fully complied with the requirements of the DWS. The DWS states (emphasis added):

> The Settling Parties agree to the following six principles (Principles), which will be applicable to PG&E's next GRC. **The Settling Parties agree that the Principles should be viewed in totality.**
>
> (1) Where funds are originally collected from ratepayers based on representations that the work is necessary to provide safe and 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 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.

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231 TURN Amended Opening Brief, p. 99.

232 Cal Advocates Opening Brief, p. 43.

> (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 a 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.
>
> [¶]
>
> Specifically, for any work that meets these [deferred work] conditions, PG&E's direct showing in support of the reasonableness of its forecast in the rate case shall provide at a minimum a demonstration of how the specific funding request is consistent with the principles above. **This demonstration may be made by a single witness who addresses all work that meets these conditions**. [233]

PG&E's testimony is consistent with and goes beyond these requirements. No party's testimony, including Cal Advocates' testimony, took issue with PG&E's showing on the six principles.

First, the testimony of PG&E witness Stephanie Williams explains how PG&E's identified deferred work is consistent with the six principles from an enterprise-wide perspective.[234] As explained by Ms. Williams:[235]

> PG&E recognizes that the six principles also have a broader relationship to the enterprise planning and budgeting processes discussed in this chapter. Accordingly, in addition to being addressed in each LOB's testimony where specific deferred work is identified, the six principles also are discussed below in the context of PG&E's overall, enterprise-level processes.
>
> The six principles should be viewed in totality and not in isolation, at both the enterprise level and the LOB level. They balance factors that should be considered when determining whether PG&E's decisions are reasonable for the operation of its systems.

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233 2020 GRC Settlement Agreement adopted in the final GRC decision, D.20-12-005, Section 5.2, "Deferred Work Principles."

234 PG&E-02, p. 3-8, line 18 to p. 3-13, line 11.

235 PG&E-02, p. 3-8, lines 18-30.

> Because of some overlap among the various principles, I describe immediately below each principle the key element(s) of that principle in order to provide additional structure for this discussion.

Ms. Williams then proceeds to discuss how PG&E's deferred work and reprioritization decisions comply each of the six principles. As the expert on enterprise-wide reprioritization processes and the Operating Rhythm, Ms. Williams is qualified to address these issues. As an officer in PG&E's Finance organization, she is also uniquely qualified to address the specific DWS principles that deal with the balance between overall spending and PG&E's financial health, such as Principles 4 and 6. Thus Cal Advocates' claim that this testimony constitutes "opinions outside the area of expertise of the PG&E witness who presented them" is simply wrong.

Second, the functional areas with identified deferred work, Electric Operations and Gas Operations, each presented testimony by a single expert witness who explained how the deferred work identified in those functional areas complied with the six principles.[236] This is appropriate and consistent with the DWS that states "This demonstration may be made by a single witness who addresses all work that meets these conditions." These expert functional area witnesses each discuss the specific identified deferred work in that functional area in the context of the six principles. Again, Cal Advocates' claim that this discussion is "outside the expertise" of the witnesses is wholly without merit.

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236 PG&E-03, p. 2-46, line 14 to p. 2-52, line 14, Section G.4 (Gas Operations); PG&E-04, p. 2-33, line 1 to p. 2-40, line 17, Sections F.4 and F.5 (Electric Operations). The Gas Operations witness, Bryon Winget, Director of Gas Investment Planning, is responsible for developing a risk based, executable investment plan for the gas distribution, transmission and storage systems of PG&E. He was formerly Director of the Transmission Integrity Management Program, as well as the Transmission Asset Family Owner. (PG&E-26, p. BW-1, lines 9-19.) The Electric Operations witness, Tatjana Rmus, is the Senor Director of the Electric Business Operations function and is responsible for developing Electric's investment plans, work, and resource plans, and leads the Integrated Planning Process for the Electric line of business. She was previously responsible for the Power Generation long term planning function. Other roles within or supporting Generation have included leading the Asset Management function, Risk & Compliance, and Business Finance. Prior to PG&E she held leadership positions at a large natural gas utility in operations, engineering, and customer attachment functions. (PG&E-13, p. TR-1, lines 8-24.)

In summary, PG&E has more than complied with the DWS requirement to explain how PG&E's identified deferred work meets the six principles by presenting detailed expert witness testimony at both the enterprise level and the LOB level. Accordingly, the Commission should disregard Cal Advocates' vague and unfounded criticisms.

2.5.3 PG&E's Financial Health

2.5.3.1 The Commission Should Not Delay Cost Recovery For Appropriate Business Expenses That PG&E Has Forecast In This Proceeding.

PG&E's Chief Financial Officer David Thomason explained in his rebuttal testimony that PG&E's credit rating will be reduced if it is required to continue to carry excessive debt in memorandum accounts.[237] Cal Advocates disputes this testimony:

> Specifically, PG&E argues that Cal Advocates and TURN' s proposals to remove capital expenditure forecasts and operations and maintenance costs from TY 2023 forecasts and instead track them in memorandum accounts on a recorded basis would significantly delay cost recovery. This argument is without merit because whether these costs are approved in this TY 2023 GRC or recorded and tracked in a memorandum account, PG&E's investors will be compensated for the time-value of their investment based on when the cost (expenditure?) was made or recorded, rather than only when it is approved. This is largely the same occurrence that the results of operations model would provide in multiplying the investment by the rate of return if these capital projects that Cal Advocates recommended are tracked and recorded until a future date, and are included in this GRC as TY 2023 forecasts.[238]

Cal Advocates misses the point of Mr. Thomason's testimony. As explained in PG&E's rebuttal testimony, excessive use of memorandum accounts to defer cost recovery is detrimental to PG&E's financial health because it delays the cash recovery of those costs.[239] Such delays,

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237 PG&E-14, p. 3-21, line 22 to p. 3-22, line 2; see PG&E Opening Brief, pp. 64-66, Section 2.5.3.1.

238 Cal Advocates Opening Brief, p. 22.

239 PG&E-14, p. 3-17, line 8 to p. 3-22, line 2.

which are typically no less than 18 months and often much longer,[240] mean that PG&E must finance those costs, including the payment of interest, with more debt. PG&E also explained that as these balancing and memorandum accounts now contain large, multi-year unrecovered costs they have essentially become equivalent to long-lived assets financed with long-term debt and equity capital – not the much less costly commercial paper that is typically assumed to be the carrying cost of these balances. Further, the commercial paper rate that is typically applied to memorandum accounts recorded balances itself is not recovered in real time, rather, it is recovered as part of the revenue requirement request in the final decision on recovery of the given memorandum account. As a result, PG&E is not recovering the cash needed to finance the costs recorded to the memorandum accounts timely, it is not recovering the full carrying cost of such large balances, and therefore it must use more debt financing for costs that should otherwise be recovered in rates concurrently with the expenditure. Because the amounts at issue here are so significant, the lack of revenue and additional debt may be enough to adversely impact PG&E's current investment grade ratings. PG&E demonstrated this potential impact on PG&E's credit metrics in PG&E-14, Table 3-3.[241] Although the figures in this table reflect all of Cal Advocates' and TURN's proposals that impact PG&E's credit quality, the proposals to defer GRC costs into memorandum accounts for future recovery are a significant factor in driving these credit metrics to a level that could result in downgrades of PG&E's credit ratings.

Cal Advocates also argues that PG&E somehow does not distinguish between the memorandum account treatments proposed by intervenors and other existing or PG&E-proposed memorandum and balancing accounts.[242] To the contrary, the distinction is plainly evident as

240 See for example PG&E's 2016 Catastrophic Events Memorandum Account cost recovery application, A.16-10-019, which received a final decision. The final decision (D.18-06-011, p. 1) was issued nearly 18 months after the initial filing and the request included recovery of costs recorded to the account all the way back to 2012, or 6 years before cost recovery was approved.

241 PG&E-14, p. 3-21, Table 3-3.

242 Cal Advocates Opening Brief, p. 23.

explained in PG&E's testimony.[243] PG&E has proposed memorandum accounts where costs that cannot be reasonably forecasted in a GRC due to timing or significant uncertainties that renders a forecast unreliable.[244] However, the costs Cal Advocates and TURN propose to record in memorandum accounts and defer cost recovery are either known or are reasonably forecasted without significant uncertainties, and are appropriate for review in this GRC. There is no need to defer review as parties, such as Cal Advocates and TURN, have had ample opportunity to conduct a review in this GRC. Neither Cal Advocates nor TURN has provided any explanation for why they cannot perform their review.

Cal Advocates also states that its proposed use of memorandum accounts is not excessive because it is proposing to "record ***only*** five cost items in memorandum accounts."[245] As explained in PG&E's Opening Brief, the five items Cal Advocates proposes to take out of the forecast and delay cost recovery through memorandum accounts exceed $2 billion in capital expenditures as indicated in Table 2-X below:

TABLE 2-1
CAL ADVOCATES' DEFERRED COST RECOVERY PROPOSALS
(MILLIONS OF DOLLARS)

Line No.	Party	Description of Item Deferred	Total Capital 2021 to 2023	2023 Expense
1	Cal Advocates	Purchase of Lakeside Office	$892	$1.2
2	Cal Advocates	Purchase of Emergency Generators	$62	$0
3	Cal Advocates	Community Rebuild	$617	$16.7
4	Cal Advocates, TURN	Catastrophic Events Straight-Time Labor Forecast	$19	$23
5	Cal Advocates	2021 and 2022 Pole Replacements Forecasts	$421	$0
6	Total		$2,011	$40.9

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243 PG&E-14, p. 3-5, line 1 to p. 3-7, line 6.

244 D.18-06-029, p. 7.

245 Cal Advocates Opening Brief, p. 23 (emphasis added).

2.5.3.2 The Commission Should Not Limit PG&E To A Return On Debt For Capital Projects

TURN's testimony proposed that PG&E's undergrounding project "should be financed entirely by debt, without a return on equity component."[246] PG&E responded to TURN's proposal in its Opening Brief in Section 2.5.3.3. TURN modified its proposal in its Opening Brief at pages 67-72. In its Opening Brief, TURN modifies its proposal as follows: "TURN emphasizes that we are not recommending that PG&E only use debt to finance the undergrounding work. PG&E should use any and all available sources of financing, but should earn a lower rate of return, comprising only the debt return, on these capital expenditures."[247]

TURN's modified proposal should be denied. It gives PG&E the choice to either use all debt financing, thus taking on excessive debt at a time when the Commission expects PG&E to reduce its total debt, or to take shareholder losses. PG&E's testimony explains why taking on excessive debt would adversely impact the Company's financial health, and potentially raises customer costs through a higher cost of capital.[248] The Commission establishes PG&E's return on capital investments in the Cost of Capital proceedings, in which TURN is an active participant.[249] TURN could have made its proposal in the CPUC's 2023 cost of capital proceeding, in which TURN is a party and served its testimony on August 8, 2022. The return on cost of capital for the undergrounding program should not be adjusted in this proceeding, as TURN belatedly proposes.

2.6 Climate Resilience

Parties did not raise any issues in their Opening Briefs which require a reply on this issue.

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246 TURN-11, p. 48, lines 10-12.

247 TURN Amended Opening Brief, p. 409.

248 PG&E-14, p. 3-12, line 20 to p. 3-16, line 24.

249 TURN is an active party to the pending 2023 Cost of Capital Proceeding, A.22-04-008.

3. GAS OPERATIONS (EXHIBIT PG&E-03)

Exhibit PG&E-03 presents Gas Operations' expense and capital expenditures forecast to operate and maintain PG&E's natural gas transmission, storage, and distribution system safely and reliably from 2023 to 2026. PG&E's Gas Transmission and Storage (GT&S) 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 also owns and operates three gas storage facilities[250] and has 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 wells, and 3,404 acres of reservoirs with over 52 billion cubic feet of working gas capacity. PG&E's gas distribution system is composed of approximately 43,000 miles of distribution mains, approximately 3.6 million gas services, and approximately 4.6 million gas meters which together provide gas to PG&E's 4.3 million residential, commercial, and industrial customers.[251]

PG&E submitted hundreds of pages of testimony and extensive and detailed workpapers in Exhibits PG&E-03 and PG&E-16 to support Gas Operations' programs and forecasts. This extensive record demonstrates that PG&E's expense and capital forecasts are just, reasonable and prudent and that its Gas Operations programs are necessary for the safe, reliable, and cost-effective operation of PG&E's natural gas transmission, distribution, and storage facilities. In this Section 3 of our Reply Brief, we respond to the disputed gas transmission, storage, and distribution forecast and non-forecast issues set forth by parties in their Opening Briefs.

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250 PG&E is currently in the process of seeking to sell or decommission the Pleasant Creek facility. See PG&E-03, p. 7-59, lines 15-24 for additional information.

251 PG&E-03, p. 1-1, lines 11-21.

3.1 Expense And Capital Forecast[252]

In Section 3.1 of its Opening Brief, PG&E provided an overview of the Gas Operations Corrected Forecasts for expense and capital expenditures for Gas Operations as a whole and separately for Gas Distribution (GD) and Gas Transmission and Storage (GT&S).[253]

In Sections 3.3 through 3.13 below, PG&E addresses specific GD and GT&S program-level forecast issues raised by parties in their Opening Briefs.

3.2 Gas Operations Risk Management

In its Gas Operations Risk Management testimony,[254] PG&E describes the risks associated with its gas transmission (GT), distribution, and storage facilities, and the processes and tools it has developed to manage these risks. PG&E also describes each of the Gas Operations or "GO" risks on PG&E's Corporate Risk Register (CRR) and provides an update to the risk management strategy and risk modeling for those Gas Operations risks that were included in PG&E's 2020 RAMP Report. No party challenged PG&E's Gas Operations' risk analysis other than TURN. In this section of our Reply Brief, we address the Gas Operations Risk Management arguments made by TURN in its Opening Brief.

3.2.1 PG&E's Testimony Was Consistent With The S-MAP Settlement

Although TURN spends considerable time in its Opening Brief discussing the S-MAP Settlement, it minimizes certain key settlement provisions. Of particular importance for Gas Operations is Row 26 in the S-MAP Settlement which provides:

> In the RAMP and GRC, the utility will clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations. The utility is not bound to select its mitigation strategy based solely on RSE ranking.

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252 PG&E's forecast overview is provided in Chapter 2 of PG&E's Prepared Testimony ("Summary of Request and Investment Planning"), PG&E-03, and further addressed in Chapter 2 of PG&E's Rebuttal Testimony, PG&E-16-E.

253 PG&E Opening Brief, p. 81, Table 3-1.

254 Gas Operations Risk Management is addressed in Chapter 3 of PG&E's Prepared Testimony, PG&E-03, and further addressed in Chapter 3 of PG&E's Rebuttal Testimony, PG&E-16-E.

> Mitigation selection can be influenced by other factors including funding, labor resources, technology, planning and construction lead time, compliance requirements, and operational and execution considerations. In the GRC, the utility will explain whether and how any such factors affected the utility's mitigation selections.[255]

This is exactly what PG&E did in its Opening Testimony for Gas Operations. We provided clear and transparent information regarding the calculation of RSE scores for specific mitigations[256], explained how RSE scores were used in developing the Gas Operations forecast[257], and then, for the asset families, described each program and why the mitigation strategy was selected. The asset family chapters (*i.e.*, Exhibit PG&E-03, Chapters 4-7) provide a detailed discussion of each program, the factors leading to program selection including regulatory requirements, industry benchmarks, and safety considerations. These chapters also describe the amount of work PG&E is proposing to perform during the rate case period. In short, our Opening Testimony "clearly and transparently explain[s]" our rationale for selecting <u>each</u> specific program and mitigation and for our overall portfolio of mitigations. This satisfies the requirements of Row 26 in the S-MAP Settlement. TURN seeks to minimize the importance of Row 26 to justify its narrow focus on RSE scores.[258] The problem with TURN's approach and its treatment of Row 26 is addressed in Section 2.3.1 above.

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255 TURN-116, p. A-14, Row 26.

256 PG&E-03, p. 3-13, line 13 to p. 3-15, line 26 (describing updated RSE scores and risk mitigation assessment for gas transmission); p. 3-18, line 3 to p. 3-29, line 30 (describing updated RSE scores and risk mitigation assessment for gas distribution).

257 PG&E-03, p. 2-22, lines 14-24.

258 TURN Amended Opening Brief, pp. 70-71.

3.2.2 The Commission Should Not Defund Gas Safety Programs Based On Low RSE Scores

TURN recommends that the Commission reject funding for seven gas safety programs simply because they have low RSE scores.[259] TURN also recommends drastically reducing other gas safety programs based again solely on low RSEs. For example, TURN relies on RSE scores to recommend: reducing by 78% PG&E's ILI Upgrade program that facilitates inspections of gas transmission pipelines;[260] reducing by two thirds the number of "cross bore" inspections that detect hazardous service installations through sewer lines;[261] and reducing by more than 60 percent funding for the Gas Pipeline Replacement Program (MAT 14A),[262] and the Plastic Pipe Replacement Program (MAT 14D)[263] which are focussed on replacing vintage gas distribution lines with a high risk of failure.

As explained in PG&E's Opening Brief, the Commission should not adopt TURN's recommendations to defund or reduce funding for safety programs solely based on RSE scores.[264] TURN's RSE score and benefit-cost ratio analysis is seriously flawed, inconsistent with Commission precedent, and uses RSE scores for a purpose that was never intended.[265] Furthermore, as discussed above, the S-MAP Settlement Agreement states that RSEs are not

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259 The gas risk mitigation programs that TURN proposes to eliminate on the basis of a low RSE score include: Gas Transmission Vintage Pipe Replacement (TURN-04, p. 52, lines 17-18); Gas Transmission Shallow and Exposed Pipe mitigation program (TURN-02, p. 108, lines 5-7); Gas Distribution Over Pressure Protection program (TURN-02, p. 113, lines 13-17); Gas Transmission Over Pressure Protection program (TURN-02, p. 116, lines 7-9); Gas Distribution High Pressure Regulator (HPR) replacement program (TURN-02, p. 119, lines 1-3); Gas Distribution Regulator Station Monitoring (SCADA) program (TURN-02, p. 124, lines 5-7); and Gas Transmission SCADA Visibility program (TURN-02, p. 127, lines 1-3).

260 TURN-04, p. 11, lines 5-21.

261 TURN-06, p. 38, Table 22.

262 TURN-06, p. 25, Table 14.

263 TURN-06, p. 21, Table 12.

264 PG&E Opening Brief, pp. 43-44, Section, 2.3.2.

265 PG&E Opening Brief, pp. 37-42, Section 2.3.1; PG&E Reply Brief, Section 2.3.

meant to be the sole determining factor regarding whether risk control or risk mitigation programs are selected for funding.[266]

The gas safety programs proposed for funding in this GRC are based on a series of prioritization investment decision meetings where proposed programs were evaluated based on contribution to risk reduction, code compliance and other safety, reliability and operational factors.[267] Contrary to TURN's claim that PG&E ignored RSE scores, PG&E considered RSE scores as part the prioritization process.[268] The basis for the selection of each program was fully described in our testimony.

In its Opening Brief, TURN continues to defend the use of RSE scores as the sole basis for its recommendations.[269] However, as discussed below, by focusing on this one factor TURN largely ignored PG&E's operational justifications for these programs or failed to address them at all. Furthermore, TURN's proposed narrow reliance on RSE scores and benefit-cost ratios will potentially do away with a large portion of Gas Operations safety programs that are prudent, reasonable and in alignment with accepted industry practices.

3.2.3 TURN's Did Not Address PG&E's Operational Justifications For Gas Safety Programs

In its Opening Brief, TURN argues that "PG&E ignored its RSE analysis in its justifications for discretionary gas programs."[270] Not only is this untrue since RSE scores were considered in PG&E's prioritization process, but it ignores the fact that contrary to the requirements of the S-MAP Settlement, TURN failed to consider anything <u>but</u> RSE scores for its recommendations.

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266 D.18-12-014, Attachment A, Appendix A, p. A-14, No. 26.

267 PG&E-03, p. 2-20, line 22 to p. 2-22, line 24.

268 PG&E-03, p. 2-22, lines 5-8. See also Tr. Vol. 5, 881:18-20, PG&E/Kerans ("The RSEs that were within my chapter and within gas were reviewed in the calibration session.")

269 TURN Amended Opening Brief, pp. 106-111, Section 3.2.2.

270 TURN Amended Opening Brief, p. 104.

For all the gas safety programs, PG&E provided extensive testimony stating the reasons for the programs. These reasons vary and are specific to each program, but include studies by regulatory bodies warning of hazardous conditions and recommending action;[271] best practices identified by industry groups;[272] PG&E's own causal evaluation studies;[273] consistency with the intent of statutes and regulations;[274] and operational objectives such as the need to have 100% visibility into system conditions to anticipate and manage incidents.[275] These reasons are discussed in Sections 3.3 through 3.13 below for the programs TURN proposes to fully or partially defund as a result of RSE scores.[276]

Furthermore, many of TURN's recommendations defy common sense. For example, in its zeal to follow RSE scores to the exclusion of all else, TURN's recommendations would: (1) eliminate installation of sulfur and debris filters necessary to ensure the proper operation of over-protection devices already installed on PG&E's system;[277] (2) deny funding for the proposal to install "slam shut" valves downstream of regulator stations to prevent pressure spikes from

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271 See e.g., PHMSA bulletins and CPUC studies of the hazard of certain vintages of plastic distribution pipe, discussed in PG&E Opening Brief, pp. 111-114, Section 3.3.4.1.

272 See e.g., American Gas Association recognition that installing secondary Over Pressure Protection devices is a leading practice discussed in PG&E Opening Brief, pp. 193-195, Section 3.5.3.1.

273 See e.g., PG&E's evaluation of causes of Over Pressure events, discussed in PG&E Opening Brief, pp. 193-195, Section 3.5.3.1.

274 See e.g., regulations under the federal PIPES Act that will require secondary Over Pressure Protection discussed in PG&E Opening Brief, p. 194 and this Reply Brief at Section 3.5.3; and state and federal regulations requiring the installation of monitoring systems of gas systems discussed in PG&E Opening Brief, p. 316.

275 PG&E Opening Brief, pp. 315-317, Section 3.10.5.1 and pp. 320-321, Section 3.10.6.1.

276 Cross Bore Inspection Program, Section 3.3.2; Gas Pipeline Replacement Program, Section 3.3.3; Plastic Pipeline Replacement Program, Section 3.3.4; Traditional ILI Upgrades, Section 3.4.1; Vintage Pipeline Replacement, Section 3.4.6; Shallow and Exposed Pipe Program, Section 3.4.8; GT and GD M&C Over Pressure Protection Program, Section 3.5.3; HPR Program, Section 3.5.4; GD SCADA Visibility Program, Section 3.10.5; and GT SCADA Visibility Program, Section 3.10.6.

277 PG&E-03, p. 6-66, lines 15-16 (OPP program MAT FHQ).

migrating to customer homes and businesses;[278] (3) deny funding to allow PG&E to install sensors on its gas system that will allow full visibility for operators to detect and manage anomalous conditions and incidents on the system;[279] and (4) deny funding for replacement of aging and obsolete regulator stations.[280] In addition to the operational reasons provided by PG&E for each of these proposals, they are all reasonable and straightforward safety measures that simply make sense. TURN's approach seems oblivious to this fact.

For the seven gas safety programs that TURN proposes to defund completely, TURN did not provide any testimony addressing the operational reasons for the programs. Instead, TURN relied solely on the RAMP-related testimony of witness Jonathan Lesser who admitted to having no gas operational experience.[281]

For example, the gas distribution and transmission Over Pressure Protection (OPP) Enhancement Program is driven by the following:[282] (1) causal evaluations of large OP events; (2) industry events such as the 2018 incident in Merrimack Valley, Massachusetts that caused a series of structure fires and explosions after high-pressure natural gas was released into a low-pressure natural gas distribution;[283] (3) identification by the American Gas Association of secondary OPP protection as a leading practice; and (4) rulemaking initiatives by PHMSA that

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278 PG&E Opening Brief, pp. 190-192, Section 3.5.3 (OPP Enhancements program).

279 PG&E Opening Brief, pp. 314-315, Section 3.10.5 and pp. 319-320, Section 3.10.6 (SCADA programs).

280 PG&E Opening Brief, pp. 196-199, Section 3.5.4 (HPR program).

281 PG&E Opening Brief, p. 195 ("As TURN acknowledged in discovery, Dr. Lesser was not testifying as an expert in gas transmission or distribution operations; has not worked as an employee of a natural gas transmission or distribution utility; is not an expert on federal integrity management regulations; and had no experience working on any committee of the AGA.")

282 PG&E Opening Brief p. 193-195, Section 3.5.3.1.

283 NTSB, Overpressurization of Natural Gas Distribution System, Explosions and Fires, Merrimak Valley, Massachusetts (Sept. 13, 2018), Report No. PAR-19-02, <https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1902.pdf > (as of Dec. 4, 2022).

would require operators to install secondary OPP devices (e.g., slam-shuts, relief valves, etc.) to prevent and mitigate OP events. TURN recommended no funding for this program based on the low RSE score.[284] However, TURN presented no testimony addressing the reasons provided by PG&E justifying the program. The same is true for all the 7 programs for which TURN recommends no funding.

In its Opening Brief, TURN downplays the fact that it ignored the operational justification for these programs. TURN's position appears to be that RSE scores nullify all other justifications and reasons given by PG&E for these programs and override the opinions of PG&E's experts. For example, regarding the OPP program, TURN calls PG&E's program drivers "qualitative arguments… contrary to the Commission's multi-year efforts to inform the record with quantitative RSE analysis that allows prioritization of risk reduction proposals."[285] The mere existence of RSE scores, however, does not mean drivers such as causal evaluations of OP events, recent industry OP events, leading or best practices recommended by the AGA, and trends in regulation being considered by PHMSA carry no weight. TURN failed to address these factors in testimony or only does so in passing in its Opening Brief. As required by the S-MAP Settlement Agreement, RSE scores are not the sole factor to be considered in evaluating programs.

3.2.4 TURN's Use Of RSE Scores Would Lead To Cancellation Of Many Reasonable And Prudent Risk Management Programs

In its Opening Brief TURN goes to great lengths to describe the results of the RAMP analysis, including RSE scores, for a number of gas operations safety programs.[286] The program list includes:

- The vintage Plastic Pipe Replacement Program that replaces pre-1985 pipe that is susceptible to crack growth and failure if subject to stress (MAT 14D)

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284 TURN-02, p. 112, lines 5-7 (GT OPP) and p. 115, lines 7-9 (GD OPP).

285 TURN Amended Opening Brief, p. 257 (emphasis omitted).

286 TURN Amended Opening Brief, p. 107, Table 6.

- The vintage Steel Pipe Replacement program that focuses on replacing pre-1941 steel pipe that is approaching 100 years of service (MAT 14A)
- The Cross-bore inspection program that focuses on inspecting 800,000 remaining locations where a gas service line could have been installed through a sewer pipe (MAT JQK)
- The Fitting Mitigation Program that focuses on replacing plastic fusion fittings that have a potential manufacturing defect (MAT JQG)
- The non-TIMP Strength Testing program that conducts tests on gas transmission pipelines to assess integrity and for purposes of determining or verifying the appropriate maximum allowable operating pressure (MAOP) (MAT 75U)
- The Traditional ILI Upgrade program that focuses on increasing the amount of transmission pipe that can be inspected by in-line inspection tools (MAT 98C)
- The Shallow/Exposed Pipe program that focusses on replacing transmission pipe that is vulnerable to damage due to its exposed location (MAT 75M, 75T and 75K)
- The Vintage Pipe Replacement program that focuses on replacing aging steel transmission pipe with acknowledged construction defects (MAT 75E).

TURN claims that these programs "rank in the bottom one-third of the risk reduction proposals for which PG&E calculated RSEs, showing that they warrant lower priority than other risk reduction activities"[287] and that "none of the proposed programs are even close to cost-effective."[288] Taking the ILI Upgrade program as an example, TURN states "this program would provide only 1.6 cents of risk reduction benefits for every dollar spent."[289]

Under TURN's flawed benefit-cost analysis and RSE scores analysis, none of these programs would be funded. This outcome defies common sense and underscores the importance going forward of addressing the issue of what role RSE scores should play, and what weight they should be accorded in GRC proceedings.

TURN's use of RSE scores and benefit-cost ratios could result in cancellation of much of Gas Operations' safety program. The list in TURN's Table 6 is partial.[290] For example, it does

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287 TURN Amended Opening Brief, p. 108.

288 TURN Amended Opening Brief, p. 108.

289 TURN Amended Opening Brief, p. 109.

290 TURN Amended Opening Brief, p. 107.

not include programs TURN proposed to cancel outright due to low RSE scores such as the OPP program;[291] SCADA visibility program;[292] and the High Pressure Regulator program.[293]

Seeking to avoid this extreme result, TURN chooses to ignore its own conclusion that none of the programs are "remotely cost effective" and recommends partial funding for some of these programs. This results in a completely arbitrary approach to its proposed forecasts. For example, TURN states "[i]n certain cases, such as the Plastic and Steel Pipeline Replacement Programs, TURN recommends significant funding reductions, but does not recommend eliminating the entire program, despite the low RSEs."[294] Similarly, TURN recommends reducing ILI Upgrades from PG&E's proposed 12 per year to 4 per year, even though TURN asserts that ILI Upgrades are not cost-effective.[295]

TURN's analysis of the overall portfolio of mitigations appears to be equally arbitrary. For example, the Shallow/Exposed Pipe program listed on TURN's Table 6 has the second highest RSE score and the second highest benefit-cost ratio of the listed programs.[296] Yet TURN recommends cancelling this program while continuing to fund other programs with much lower scores.

All this illustrates that unreasonable outcomes result from TURN's recommended approach of applying RSE scores as the main driver for funding decisions. TURN's arbitrary

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291 Gas Distribution Over Pressure Protection program (TURN-02, p. 113, lines 13-15); Gas Transmission Over Pressure Protection program (TURN-02, p. 116, lines 7-9).

292 Gas Distribution Regulator Station Monitoring (SCADA) program (TURN-02, p. 124, lines 5-7); and Gas Transmission SCADA Visibility program (TURN-02, p. 127, lines 1-3).

293 Gas Distribution High Pressure Regulator (HPR) replacement program (TURN-02, p. 119, lines 1-3).

294 For these two programs TURN claims to have uncovered higher risk tranches that it deems worthy of funding. TURN Amended Opening Brief, p. 110. PG&E has addressed the merits these claims for the plastic and steel programs PG&E Opening Brief, pp. 102-104, Section 3.3.3 and pp. 108-111, Section 3.3.4.

295 TURN Amended Opening Brief, p. 179.

296 TURN Amended Opening Brief, p. 107.

application of this principle underscores the need for the Commission to address the role of RSE scores in future GRC's to avoid the type of arbitrary results that are evident in TURN's analysis.

3.2.5 TURN's Criticisms Of PG&E's RAMP Implementation Are Unfounded

In its Opening Brief, TURN reiterates several claims regarding PG&E's implementation of the RAMP proceeding. First, TURN continues to argue that PG&E failed "to use available data to properly disaggregate programs into more appropriate tranches."[297] However, as PG&E discussed in its Opening Brief, the gas operations risk model tranches are reasonable and consistent with the limits of current data and risk modelling.[298]

Second, TURN continues to claim that PG&E has "disavowed" the RSE scores for its programs.[299] This is simply not the case. PG&E's position is that model development and RSEs have not reached the level of maturity where they can reasonably be used in the manner that TURN proposes.[300] The Commission's staff has also recognized that "risk spend efficiency (RSE) values, intended to assist with Commission decision-making on utility proposed safety mitigations, are poorly understood and offer little guidance in determining the cost-efficiency of proposed investments for the Commission."[301]

Third, TURN claims that "in response to a series of TURN data requests, PG&E's gas witnesses consistently point to the results of PG&E's RSE analysis as providing the company's 'best assessment' of the risk reduction benefits from its proposed programs."[302] This claim overstates PG&E's position. In each referenced discovery request, TURN asked the following question:

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297 TURN Amended Opening Brief, p. 110.

298 PG&E Opening Brief, pp. 87-90, Section 3.2.2.1.

299 TURN Amended Opening Brief, p. 105.

300 PG&E Opening Brief, p. 38.

301 PG&E Opening Brief, p. 40, citing PG&E-29, Attachment A (SPD Proposal).

302 TURN Amended Opening Brief, p. 104-105.

> What is PG&E's best assessment of the risk reduction that would result from PG&E's proposal? Provide a page and line and/or Excel cell citation to any testimony or workpapers on which this response is based. If this response differs from the analysis PG&E provided in its workpapers to calculate the RSE for this proposal, please explain how and why it is different. [303]

Since the question was clearly seeking a quantitative analysis of risk reduction, PG&E's responses all cited to the most up-to-date RSE scores for the program. TURN did not ask for other factors, expressly allowed by the S-MAP Settlement, that supported the mitigation programs proposed by PG&E. These responses should be read within the context of PG&E's overall position on the maturity of risk modelling, and what the appropriate use should be of these scores.[304] As explained in PG&E's testimony, for each program PG&E provides the operational drivers for these programs that are based on a variety of factors other than RSE scores.

3.2.6 TURN's Arguments Regarding The ILI Upgrade Showing

In addition to its general arguments regarding the use of RSEs and the low RSE scores for specific programs, TURN makes additional arguments specific to the In-Line Inspection or "ILI" Upgrade program. First, TURN incorrectly asserts that we are trying to "discredit" our RSE analysis for ILI Upgrades.[305] Before addressing TURN's arguments, some context is important. In Opening Testimony, PG&E clearly explained how RSE scores were used in the development of the Gas Operations' forecast. We indicated that RSE scores were one of a number of inputs considered:

> After work type categorizations, subcategorization flags, and RSE score calculations were complete, Business Process Governance and Business Finance held calibration sessions with the AFOs and witness teams. The calibration sessions facilitated consistent application of the portfolio prioritization process, SME input and judgement, and data. Work was compared within each work type within each Asset Family to identify areas of potential prioritization. Potential areas for prioritization across Asset Families were aggregated and discussed.

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303 See, e.g., TURN-124, DR_TURN_225-Q001, subpart c.ii.

304 PG&E's position on the role of RSE analysis in decision making is discussed above in Section 2.3.1 of this Reply Brief.

305 TURN Amended Opening Brief, pp. 111-117.

> Cross reference to Risk Informed Budget Allocation (RIBA) was utilized to ensure consistent application with prior decisions. Final decisions were made by GO senior leaders at WFR Governance Committee meetings.[306]

We also clearly explained that our primary risk management tools for Gas Operations are the Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP) risk models and described how these risk models interact with the EORM risk assessment process.[307]

In addition, our Opening Testimony described the factors that we considered when we developed our forecast for each program included in this rate case. For example, our Opening Testimony and workpapers regarding the ILI Upgrade program included a detailed discussion of the safety and reliability benefits of ILI, regulations and Commission directives supporting ILI, and industry standards and progress.[308] TURN simply ignored this information. TURN also ignored PG&E's testimony which clearly explains how RSEs were incorporated into the development of our Gas Operations forecasts.

Second, TURN asserts that PG&E waited until Rebuttal Testimony to indicate that the RSEs for ILI Upgrades did not capture the program's full benefits and that the ILI Upgrade RSE scores were lower than they should have been.[309] However, because RSEs were not the only factor used to develop our forecasts, it is entirely reasonable that while our Opening Testimony included the RSEs for ILI Upgrades[310], it did not go into extensive detail regarding areas for improvement in the current RSE approach. Moreover, our Opening Testimony made clear that RSE scores evolve and are updated as we refine our methodology or obtain new information.

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306 PG&E-03, p. 2-22, lines 14-24.

307 PG&E-03, p. 3-6, lines 9-11; p. 3-7, lines 5-17.

308 PG&E-03, p. 5-21, line 1 to p. 5-28, line 10; PG&E-03, WP 5-55 to WP 5-56.

309 TURN Amended Opening Brief, p. 112.

310 PG&E-03, p. 3-14, Table 3-2, Line 6 (providing ILI Upgrade RSE).

For example, in Opening Testimony, we updated the 2020 RAMP Report RSEs with additional and new information and methodology refinements.[311]

Third, TURN points to inadvertent errors in the calculation of the RSEs for ILI Upgrades, which are a mitigation, and ILI assessments, which are a control.[312] PG&E does not dispute that there were errors in our RSE calculations for ILI Upgrades and ILI assessments, which included: (1) failing to account for all of the benefits of ILI Upgrades; and (2) double-counting certain benefits for both programs. When we identified these errors right before hearings,[313] we immediately corrected our discovery responses and provided the revised discovery responses to TURN before the hearing.[314] During the hearing, PG&E's witness Vincent Tanguay fully and transparently described the errors and explained their implications.[315] Indeed at the end of Mr. Tanguay's testimony, TURN's counsel expressed his appreciation for Mr. Tanguay's "forthright answers."[316] TURN was also given permission by the ALJs to call PG&E witnesses back to testify regarding the errors and corresponding data request corrections[317], but TURN ultimately elected not to do so. And as TURN's lead counsel indicated at the hearing, there is nothing "untoward or problematic" about a party discovering errors in their testimony or discovery responses and correcting those errors when discovered.[318] In short, there is no dispute that: (1) PG&E's error in RSE calculations for ILI Upgrades and ILI inspections was inadvertent; (2) PG&E notified TURN of the error as soon as it was discovered and corrected data responses; and

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311 PG&E-03, p. 3-14, Table 3-2.

312 TURN Amended Opening Brief, pp. 113-116.

313 Tr. Vol. 5, p. 808:15 to 810:7, PG&E/Tanguay.

314 TURN-121 (corrected discovery responses); Tr. Vol. 5, p. 797:19 to 798:18, PG&E/Tanguay.

315 Tr. Vol. 5, 783:9 to 807:1, PG&E/Tanguay.

316 Tr. Vol. 5, p. 806:19, TURN/Long.

317 Tr. Vol. 5, 769:26 to 770:22, TURN/Long.

318 Tr. Vol. 13, p. 2494:9-17, TURN/Goodson.

(3) at the hearing PG&E's witness fully and transparently described the errors and their impact on RSE calculations. As Mr. Tanguay explained, given the shortcomings identified, PG&E will be re-thinking its RSE approach for the ILI program in the next RAMP proceeding.[319]

Fourth, TURN argues that as a result of the inadvertent RSE calculation error, the ILI Upgrade RSE was higher than it should have been.[320] As Mr. Tanguay explained at the hearing, correcting the RSE calculation error would likely result in a reduction to the ILI Upgrade risk reduction score because the benefits of first-time ILI inspections were counted for both ILI Upgrades and ILI assessments.[321] However, Mr. Tanguay also explained that certain ILI Upgrade benefits were not included in the ILI Upgrade RSE score.[322] These benefits would likely increase the RSE score. The exact impact of these corrections, both up and down, was not calculated and will likely be addressed in the next RAMP proceeding. More importantly, TURN misses one of the fundamental flaws in its own argument. As PG&E witness Barnes explained in Rebuttal Testimony, the RSE scores and risk reduction benefits of ILI Upgrades cannot be considered in isolation.[323] TURN does not dispute that there are significant risk reduction benefits associated with ILI assessments and repairs. However, ILI inspections and repairs cannot occur until a pipeline has been upgraded to allow ILI inspections and repairs. Thus, while the RSE score of ILI Upgrades in isolation may be low, when considered with the corresponding benefits of ILI assessments and repairs, the risk reduction value of the overall ILI program is substantial.

Finally, TURN recommends the Commission consider a potential Rule 1.1 violation based on the inadvertent errors in PG&E's discovery responses that cascaded into PG&E's

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319 Tr. Vol. 5, 800:8-23, PG&E/Tanguay.

320 TURN Amended Opening Brief, pp. 114-115.

321 Tr. Vol. 5, 810:11 to 811:27, PG&E/Tanguay.

322 Tr. Vol. 5, p. 795:3-9; 801:11 to 802:2, PG&E/Tanguay.

323 PG&E-16-E, p. 5-14, lines 5-18.

Rebuttal Testimony regarding the RSE scores for ILI Upgrade and ILI assessments. TURN asserts that at the hearing, PG&E witness Bennie Barnes failed to correct a single paragraph in 88 pages of his Rebuttal Testimony and thus he should not have testified at the hearing that his testimony was correct.[324] It is important to put TURN's argument into context. Mr. Barnes' Rebuttal Testimony cited and repeated a discovery response regarding the RSE calculations for ILI Upgrades.[325] The discovery response referred to in the Rebuttal Testimony was corrected just prior to hearing. However, given the volume of discovery and testimony in this proceeding, PG&E did not recall when Mr. Barnes testified at the hearing that the erroneous discovery response had been used in testimony and thus needed to be corrected as well. The problem with Mr. Barnes' testimony was pointed out at the hearing and Mr. Barnes promptly indicated that his testimony should have been corrected as well.[326] This is the only error in PG&E's testimony that TURN points to for its Rule 1.1 recommendation.[327]

As described above, there is no dispute that PG&E's RSE calculation error for ILI Upgrades was inadvertent, that it was discovered just before hearings started and that, once discovered, PG&E immediately notified TURN, corrected its discovery responses, and explained the error at the hearing during cross-examination. There is no evidence that Mr. Barnes deliberately did not correct his testimony or that Mr. Barnes and PG&E counsel recognized this error before cross-examination. When the error in his testimony was pointed out during cross-examination, Mr. Barnes promptly and transparently indicated the testimony was incorrect.

TURN's recommendation for a Rule 1.1 violation is undercut by the testimony of its own witness. During cross-examination regarding errors that arise in discovery and testimony, TURN

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324 TURN Amended Opening Brief, pp. 116-117.

325 PG&E-16-E, p. 5-14, lines 5-13 and fn. 28.

326 Tr. Vol 5, 890:19 to 893:2, PG&E/Barnes.

327 TURN Amended Opening Brief, pp. 113-114 (pointing to Mr. Barnes testimony as erroneous based on the revised discovery responses), pp. 116-117.

witness Catherine Yap testified, "[i]t is definitely possible for an error to cascade and for the error to go unnoticed in a portion. Particularly, if it's numerical, sometimes downstream it will look unnoticed for some time; that is a possibility."[328] Here, this is exactly what happened. PG&E identified errors in discovery and promptly corrected those errors but did not immediately identify the cascading impact on testimony of correcting the discovery response. This resulted in one paragraph in a single Q&A of Rebuttal Testimony being incorrect. And when it was pointed out, it was promptly corrected. Given the circumstances of this case, TURN's proposal for a Rule 1.1 violation is unwarranted.

3.3 Asset Family – Distribution Mains And Services[329]

This Distribution Mains and Services asset family includes 43,000 miles of gas distribution mains and provides natural gas service to approximately 4.6 million residential, commercial, and industrial customers. Distribution Mains and Services includes assets such as distribution pipelines, risers, pits and vaults, valves and ancillary services (*e.g.*, cathodic protection). The programs in this asset family include PG&E's Distribution Integrity Management Program (DIMP), distribution pipeline replacement programs, distribution service replacement programs, and other gas distribution reliability work. In this section of our Reply Brief, we address issues regarding our Distribution Mains and Services program forecasts raised by parties in their Opening Briefs:

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328 Tr. Vol. 13, 2421:4-9, TURN/Yap.

329 Asset Family – Distribution Mains and Services is addressed in Chapter 4 of PG&E's Prepared Testimony, PG&E-03, and further addressed in Chapter 4 of PG&E's Rebuttal Testimony, PG&E-16-E.

TABLE 3-1
DISTRIBUTION MAINS AND SERVICES DISPUTED PROGRAMS

Section	Disputed Program	Parties
3.3.1	Fitting Mitigation Program	TURN, Cal Advocates
3.3.2	Cross Bore Program	TURN
3.3.3	Gas Pipeline Replacement Program (GPRP)	TURN, Cal Advocates
3.3.4	Plastic Pipe Replacement Program	TURN, Cal Advocates, AARP
3.3.5	Reliability Service Replacement Program	TURN, Cal Advocates

3.3.1 Fitting Mitigation Program – Expense (MAT JQG)

Over a 10-year period, PG&E proposes mitigating 22,000 potentially defective plastic fillings installed on PG&E's gas distribution system through the Fitting Mitigation Program.[330] The fittings, that connect service lines to main gas distribution lines, are subject to potential failure on the service-side piping caused by an incomplete fusion between fitting components during manufacturing.

PG&E forecast $15.9 million of expense in 2023 for this program.[331] TURN does not disagree with the goal of replacing these fittings but proposes a 50 percent reduction ($8.0 million)[332] by extending the program's mitigation pace from 10 to 20 years. Cal Advocates proposes no funding for the program.[333] Below, we respond to the arguments made by TURN and Cal Advocates in their Opening Briefs.

3.3.1.1 TURN's Slower Mitigation Pace Should Be Rejected

In its Opening Brief, PG&E addressed TURN's proposal to slow down the program.[334] PG&E's 10-year proactive risk-informed approach to mitigate the defective fittings by the time they reach half of their estimated 29-year life is more reasonable than TURN's 20 year pace and

330 PG&E-03, p. 4-19, line 1 to p. 4-21, line 10.

331 PG&E Opening Brief, p. 95, Table 3-4.

332 TURN-06, p. 30, lines 1-6.

333 CALPA-02, p. 4, lines 12-13.

334 PG&E Opening Brief, pp. 95-96, Section 3.3.1.1.

should be approved. Slowing the pace to 20 years would likely increase both the failure rate and the potential for injury and property damage caused by gas migration and ignition from a loss of containment event.[335]

In its Opening Brief, TURN disputes the validity of PG&E's calculated mean time to failure (MTTF) of 29 years for the defective fittings. TURN claims "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, and the study included absolutely none of the defective fittings at issue in this program, since to date none of those fittings have failed."[336] Without any basis, TURN then speculates that "the behavior of the fittings with manufacturing defects is different from the behavior of poorly constructed plastic fusion fittings."[337]

PG&E's estimate of a 29-year expected life for the defective fittings is reasonable despite these claims. Given how recently the defective fittings that PG&E proposes to replace were installed, there have not yet been any observed field failures. PG&E therefore analyzed 496 plastic fusion service leaks, where failure was due to poorly-made fusions, to determine a 29 year MTTF.[338] It is entirely reasonable to assume that poorly-constructed fusion fittings will have a similar expected life regardless of whether the defect resulted from the manufacturing process, or during installation and construction. TURN points to no evidence that these situations are not analogous. The Commission should therefore find that PG&E's estimate of a 29-year expected life for the defective fittings it proposes to replace is reasonable and justifies proactively mitigating the fittings as proposed by PG&E.

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335 PG&E-16-E, p. 4-10, line 29 to p. 4-11 line 2.

336 TURN Amended Opening Brief, p. 168.

337 TURN Amended Opening Brief, p. 169.

338 PG&E-16-E, p. 4-11, lines 11-16.

3.3.1.2 Cal Advocates' Proposal To Deny Funding Should Be Rejected

In its Opening Brief, PG&E addressed Cal Advocates' proposal to provide no funding for this program.[339] In response to Cal Advocates' arguments, PG&E explained that (1) although its pilot program was still in progress, PG&E based its unit costs on the most comprehensive information available at the time it prepared its forecast, including vendor bids and engineering analysis to complete the pilot program scope of work;[340] (2) the proposed work was not previously funded under the Mechanical Fitting Program addressed in the 2020 GRC which targeted a separate and distinct fitting;[341] and (3) it is appropriate for customers to fund the fitting mitigation program because PG&E took reasonable steps to minimize the risks associated with the defect, and such funding is consistent with past Commission practice to fund remediation of manufacturing defects discovered in products.[342]

In its Opening Brief,[343] Cal Advocates argues additionally that: (1) PG&E failed to incorporate the lessons from the pilot program into its forecast; (2) PG&E failed to utilize the pilot program results in its cost and unit forecast; and (3) PG&E failed to aggressively pursue its civil remedies against the manufacturer. PG&E addresses these new arguments below.

Cal Advocates states that the purpose of the pilot program was to gather information on "the process of field locating, excavating, and repairing or replacing fittings" and that PG&E failed to incorporate this information into its proposal.[344] However, this information was not available when PG&E prepared its forecast, and other available information such as vendor bids was utilized instead.[345] The fact that the pilot program was not complete when PG&E prepared

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339 PG&E Opening Brief, p. 95.

340 PG&E Opening Brief, pp. 96-97, Section 3.3.1.2.

341 PG&E Opening Brief, p. 97, Section 3.3.1.3.

342 PG&E Opening Brief, p. 97.

343 Cal Advocates Opening Brief, pp. 51-54, Section 3.3.1.

344 Cal Advocates Opening Brief, p. 52.

345 PG&E Opening Brief, p. 96.

its forecast does not mean that the forecast lacks a reasonable basis, or that PG&E will not incorporate the practical lessons learned from the pilot as it implements the program going forward.

Cal Advocates also criticizes PG&E's unit and unit-cost forecast for not incorporating the results of the pilot.[346] The 2023 unit forecast was calculated by subtracting an estimate of fittings to be mitigated through the pilot program from 2020 to 2022 (480 units) from the starting population of approximately 22,300 fittings and dividing the remainder over a 10 year period.[347] Cal Advocates claims that the unit forecast is flawed because in fact the pilot only completed 279 mitigations, not 480. This statement is incorrect. The plastic fusion pilot program work began in 2020 and completed 279 mitigations <u>in 2020</u>, with a cost of approximately $1.4 million.[348] At the time of the 2023 GRC filing, June 30, 2021, the pilot program was not complete; however, after the filing, PG&E completed the pilot projects.[349] PG&E's unit forecast was therefore based on an accurate estimate of units to be completed under the pilot. As explained by PG&E in its Opening Brief, the unit cost forecast was based on best available information and could not, and does not, include the recorded results of the pilot program which was not complete at that time. This observation by Cal Advocates does not demonstrate that the available data and information used by PG&E resulted in an unreasonable forecast.

Finally, contrary to Cal Advocates' assertion,[350] there is no evidence that PG&E did not aggressively pursue its legal remedies against the supplier of the plastic fusion fittings. The

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346 Cal Advocates Opening Brief, p. 52.

347 PG&E-16-E, p. 4-13, lines 22-25.

348 PG&E's response to Data Request Cal Advocates_056-Q07 dated 9/22/21, p. AppA-15.

349 PG&E-16-E, p. 4-12 line 27 to p. 4-13 line 3.

350 Cal Advocates Opening Brief, p. 53.

recovery of damages from the supplier was resolved in PG&E's bankruptcy.[351] The size of the recovery was based on the legal arguments made as part of that claim, including the terms of applicable warranties and contracts.

3.3.2 Cross Bore Program – Expense (MAT JQK)

A cross bore is an inadvertent placement of an underground utility through a wastewater or storm drain system during trenchless construction. Cross bores pose a risk as they can result in a gas leak into the sewer system if damaged during mechanical sewer cleaning operations presenting a high risk to public and employee safety. This program utilizes video equipment to inspect wastewater lines and laterals for potential cross bore situations and any cross bores identified from the inspections are repaired.[352]

PG&E's 2023 forecast for the Cross Bore Program is to execute 45,000 inspections at a cost of $753 per unit (inspection) with a 2023 forecast of $33.9 million.[353] TURN, the only party to object to this program forecast, proposes a forecast of $13.1 million (a 62% reduction) based on a reduced inspection pace (19,313 inspections per year instead of 45,000 per year) and a reduced unit cost ($680 per unit instead of $753).[354] Below, we respond to the arguments made by TURN in its Opening Brief to support its position.[355]

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351 PG&E Opening Brief, pp. 97-98, Section 3.3.1.4. The recovery amount represented by the bankruptcy resolution of the warranty claim was $225,000 for defective products, including the defective plastic fusion fittings. (Tr. Vol. 5, 887:13-17, PG&E/ Kerans.) This amount of recovery was not of sufficiently significant value or volume to change PG&E's forecast. See Tr. Vol. 5, 884:3-5, PG&E/ Kerans.

352 PG&E Opening Brief, p. 99. PG&E-16-E, p. 4-16, lines 18-25. See also PG&E-03, p. 4-13, line 13 to p. 4-18.

353 PG&E-03, WP 4-9, lines 1-3.

354 Tr. Vol. 13, 2433:4-7, TURN/Sugar.

355 TURN Amended Opening Brief, pp. 169-175, Section 3.3.5.

3.3.2.1 Cross Bores Represent A Significant Risk That Should Be Mitigated At PG&E's Proposed Pace

In its Opening Brief, PG&E responded to TURN's assertion that the risk of cross bores outside of San Francisco is not significant enough to justify the Cross Bore Program. Specifically: (1) even though the cross bore find rate has declined, PG&E can expect to find and mitigate 36 cross bores per year over the 4-year GRC forecast, each of which could have catastrophic consequences if not addressed;[356] (2) of the seven loss of containment events as a result of cross bores from 2016 to present, all have been outside San Francisco;[357] (3) at TURN's recommended pace of 19,313 inspections per year, the remaining 800,000 inspections would take 41 years to complete, compared to approximately 18 years under PG&E's proposal, creating significant risk exposure over a much longer period;[358] (4) reliance on the RSE score for this program as the sole reason to delay these safety inspections is also not warranted in light of the evolving nature of the RAMP process;[359] and (5) given the significant number of potential cross bores remaining on PG&E's system, TURN's proposal to eliminate or shrink the program is unwarranted.[360]

TURN raises three new arguments in its brief to support its proposal to cut back this program: (1) PG&E's assumption that the probability of a major event resulting from a cross bore loss of containment is 1 out of 34 is flawed;[361] (2) PG&E is proposing to double its cross bore program outside San Francisco without justification;[362] and (3) there is no reason to expect

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356 PG&E Opening Brief, p. 101, Section 3.3.2.2.

357 PG&E Opening Brief, p. 101, Section 3.3.2.2.

358 PG&E Opening Brief, p. 100.

359 PG&E Opening Brief, p. 101.

360 PG&E Opening Brief, pp. 100-101, Section 3.3.2.1.

361 TURN Amended Opening Brief, pp. 171-172.

362 TURN Amended Opening Brief, pp. 172 and 173.

a major cross bore event because "sewers are designed to mitigate gas backflow into structures."[363] PG&E responds to these arguments below.

First, TURN takes issue with PG&E's risk calculation that assumes the risk of a major loss of containment event from cross bore is 1 in 34.[364] However, as PG&E explained: "[t]he method PG&E uses to estimate the probability of a major event was recommended by the SED in its review of PG&E's 2017 RAMP Report."[365] PG&E believes this assumption is reasonable and consistent with staff input. The Commission should therefore disregard TURN's criticism.

Second, TURN's assertion that PG&E is proposing "to more than double its cross bore work"[366] is inaccurate. The focus on completing San Francisco inspections reduced the number of inspections that PG&E was able to complete outside San Francisco from 2020-2022. However, in 2018 PG&E performed relatively few inspections in San Francisco, but completed 45,477 inspections outside San Francisco.[367] Given that the program will move outside San Francisco in 2023, there is no justification to limit the program going forward to the 19,313 average of non-San Francisco inspections performed outside San Francisco in 2019-2021. TURN also states: "[t]here is no safety rationale for expanding the number of inspections conducted outside of the high population density area above the historical recorded average."[368] PG&E disagrees. As explained above, and in PG&E's Opening Brief, significant risk of loss of containment remains in the 800,000 inspections to be performed outside San Francisco.[369]

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363 TURN Amended Opening Brief, p. 172.

364 TURN Amended Opening Brief, p. 172.

365 TURN-200, p. 024, PG&E's Response to TURN_219-Q006, fn.1. See also, Tr. Vol. 5, 829:lines 2-19, PG&E/Kerans.

366 TURN Amended Opening Brief, p. 172.

367 PG&E-16-E, PG&E's Response to TURN_194-Q001, dated 6/9/22, AppA-18 to AppA-19.

368 TURN Amended Opening Brief, pp. 173-174.

369 PG&E Opening Brief, pp. 100-101, Section 3.3.2.1.

Third, referring to PG&E's RAMP analysis TURN states "cross bores constitute less than 2 percent of the loss of containment risk for mains and services."[370] What TURN fails to point out, however, is the significant disproportionate risk compared to frequency (1.6% of risk for 0.003% of frequency)[371] which indicates that while cross bore incidents are infrequent, they are high consequence events. Each cross bore located and mitigated reduces the likelihood of a catastrophic event, where gas could migrate into customer homes via the sewer resulting in an explosion of a single or multiple homes in the affected area(s).[372] The catastrophic financial consequence of a cross bore event is difficult to estimate based on the range of scenarios (one or several natural gas ignitions that could occur), but reasonably could be tens of millions of dollars based on the unique circumstances of the event; not to mention the potential for personal injury or loss of life.[373] It is therefore not prudent to reduce the forecast, the unit cost, or pace of the Cross Bore Program as it is needed to mitigate low frequency events with the potential for catastrophic impacts that not only may have significant financial consequences, but safety related consequences for those who are involved.[374]

Finally, the Commission should accord no weight to TURN's implication that the risk of migration of gas into a home as a result of a cross bore is of no concern due to plumbing regulations that require a liquid seal that will prevent the back passage of air.[375] Aside from referring to the San Francisco plumbing code, TURN offers no evidence that these codes have any mitigating effect on cross bore loss of containment events. These codes address sewer gas, not natural gas that is delivered at pressures greater than atmospheric pressure. PG&E's expert,

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370 TURN Amended Opening Brief, p. 172.

371 PG&E-03, p. 3-18, Fig. 3-3, Risk Bowtie for LOC on Gas Distribution Main or Service.

372 PG&E-16-E, p. 4-19, lines 5-8.

373 PG&E-16-E, p. 4-19, lines 12-17.

374 PG&E-16-E, p. 4-19, lines 22-26.

375 TURN Amended Opening Brief, p. 172, fn. 478.

Mike Kerans testified on cross examination that he was "not aware of any studies related to the severity of cross bores, based on construction methodology of sewer systems or storm drain systems."[376] Furthermore, PHMSA's public database describes an incident on May 14, 2004, where an auger was used to clear a sewer blockage. This punctured the gas service, which was inadvertently bored through the sewer lateral during service installation, resulted in gas migration through the sewer lateral into the basement that ignited and exploded. There were five injuries and one fatality as a result of this incident.[377] While it is not clear how the gas leaked into the basement, these facts suggest that serious leakage can occur before the gas reaches any plumbing seal within the dwelling.

For all these reasons, the Commission should adopt PG&E's unit forecast of 45,000 inspections in 2023 as a reasonable pace of identifying and mitigation the remaining cross bores on PG&E's gas system.

3.3.2.2 The Unit Cost For The Program Is Reasonable

PG&E's forecast of a unit cost of $753 is reasonable and reflects PG&E's expectation that inspections outside San Francisco will include a certain proportion of more complex, and therefore costly installations.[378] TURN's proposed unit cost of $680[379] does not take into account that going forward installations outside San Francisco will need to address a certain amount of more costly installations. TURN claims that "the actual unit cost of inspections conducted outside of San Francisco inherently includes the costs of any complex inspections

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376 Tr. Vol. 5, 863:6-9, PG&E/Kerans.

377 The data base of incidents is found at <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/data_statistics/pipeline/PHMSA_Pipeline_Safety_Flagged_Incidents.zip> (as of Dec. 5, 2022). The file name is "gdmar2004to2009.xlsx" and the incident can be found by filtering on column E (RPTID) for "20040140".

378 PG&E Opening Brief, pp. 101-102, Section 3.3.2.3.

379 TURN Amended Opening Brief, p. 175.

outside of San Francisco."[380] However, although PG&E was able to identify approximately 5,022 units outside of San Francisco where the condition or configuration of the sewer or storm system prevented an inline camera inspection, thus requiring an alternative solution, the 5,022 locations have not yet been completed. Thus, historic cost data for inspections outside San Francisco likely does not include the higher costs of completing these difficult inspections.[381] Accordingly, PG&E used a three-year average (2017-2019) of recorded spend and recorded units for the development of the Cross Bore Program 2023 unit cost forecast. This approach takes into account the costs of a small population of difficult inspection units outside of San Francisco each year, similar to those encountered in San Francisco.[382] The Commission should therefore adopt PG&E's unit cost forecast of $753 per inspection in 2023.

3.3.3 Gas Pipeline Replacement Program

The Gas Pipeline Replacement Program (GPRP) is focused on deactivating higher risk steel distribution pipe, including pre-1941 steel pipe, and bare or non-cathodically protected steel pipe.[383] The forecast for GPRP is to replace approximately 40 miles of pipe per year for a total of approximately 161 miles during the GRC period.[384] The 2023 forecast is $151.7 million of capital spend, and $683.3 million over 4 years.[385]

TURN recommends 15 miles per year, or a total of 60 miles over the four-year 2023 GRC cycle (2023-2026) instead of the 161 miles PG&E proposes over the same timeframe, a reduction of 101 miles. TURN proposes a reduction of approximately $429.5 million to

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380 TURN Amended Opening Brief, p. 174.

381 TURN-200, p. 022, PG&E's Response to TURN_219-Q004.

382 PG&E-16-E, p. 4-22, lines 3-21.

383 PG&E-03, p. 4-29, line 9 to p. 4-30, line 22.

384 PG&E-16-E, p. 4-31, lines 12-15.

385 PG&E Opening Brief, pp. 102-103 and Table 3-6.

PG&E's 2023-2026 forecast of $683.3 million.[386] Cal Advocates proposes reducing PG&E's 2023 steel pipe replacement mileage from 37.1 miles to 27.9 miles.[387] Below, we respond to the arguments made by TURN[388] and Cal Advocates[389] in their Opening Briefs to support their respective positions.

3.3.3.1 PG&E's Proposed Replacement Of Pre-1941 Steel Pipe Addresses End-Of Life Risks And Is Consistent With Prudent Asset Management

PG&E's pace of 161 miles of pre-1941 steel pipe over 4 years is necessary to replace distribution pipelines before they reach end-of-life and fail at an unmanageable rate that makes it infeasible from a resource perspective to repair or replace failing assets.[390] PG&E has 1,730 miles of pre-1941 vintage steel distribution pipe.[391] All this steel pipe has already been in the ground for longer than 80 years. PG&E's determination to proactively replace this aging pipe before it reaches its expected 100-year asset life is therefore entirely reasonable and prudent and not "arbitrary" as TURN claims.[392] TURN's proposed replacement rate of 15 miles per year, compared to PG&E's proposal of 40 miles per year, virtually guarantees that aging, deteriorating vintage steel pipe will remain in the ground until it fails in service.[393]

PG&E's proposal ensures that by 2030, PG&E's will be replacing pre-1941 steel pipe before it reaches its 100-year life. This is known as the steady-state replacement rate. This pace of replacement is consistent with PG&E's Asset Management Plan and with the Commission's

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386 TURN-06, p. 25, Table 14.

387 CALPA-02, p. 12, Table 2-10 shows Cal Advocates' corresponding funding proposals.

388 TURN Amended Opening Brief, pp. 156-165, Section 3.3.2.

389 Cal Advocates Opening Brief, pp. 56-57, Section 3.3.3.

390 PG&E Opening Brief, pp. 105-107, Section 3.3.3.2.

391 PG&E-16-E, PG&E's response to Data Request TURN_048_Q001Atch01, dated 11/16/21, p. AppA-27.

392 TURN Amended Opening Brief, pp. 164-165.

393 PG&E Opening Brief, p. 106.

directive that PG&E strive for "for reasonable rates of steady state replacement" and "to reduce post-failure replacement for assets where failure can result in unreasonable safety or cost impacts."[394]

TURN's claim that the parameters of the GPRP are based "*solely* on the pipe vintage"[395] is not correct. In 2002, the GPRP was expanded to include pre-1941 steel following a reevaluation of the scope of the program that had previously included pre-1931 pipe.[396] Moving the cut-off date from pre-1931 pipe to pre-1941 pipe was the result of further study and evaluation of risks and changing circumstances, and not an arbitrary decision as TURN implies.

In its Opening Brief, TURN argues that steel pipe between 1923 and 1941 does not pose sufficient risk to be subject to a proactive risk replacement program.[397] TURN's basis for this recommendation is that pre-1924 pipe is "the most leak prone pipe," because the data shows that that steel pipe installed between 1900 through 1923 has a leak rate of 0.43 leaks per mile, while pipe installed from 1924 through 1941 has a leak rate of only 0.21 leaks per mile.[398] However, leak rate is not the only factor that determines risk of a pipe segment. PG&E's risk ranking of pipe segments is based on a methodology that considers pipe age, leak history, cathodic protection, coating, seismic activities, and population proximity. In other words, a single leak on pre-1924 pipe may not carry as much risk as one or more leaks on a post-1924 pipe once all these other factors are considered.[399]

In addition, TURN's focus on leak rate fails to address the significant total volume of leaks on 1924-1940 pipe. From 2016-2020, 1924-1940 steel pipe had 1,625 leaks, while 1900-

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394 PG&E Opening Brief, p. 106, citing 2020 General Rate Case Settlement Agreement, Section 5.1, approved in D.20-12-005, pp. 35-36.

395 TURN Amended Opening Brief, p. 161.

396 PG&E-03, Gas Pipeline Replacement Program 2020 Annual Report, WP 4-169.

397 TURN Amended Opening Brief, p. 162.

398 TURN-06, p. 23, lines 4-13; p. 25, lines 6-11 and PG&E-16-E, p. 4-25, lines 14-20.

399 PG&E-16-E, p. 4-27, lines 1-33.

1923 pipe had only 62 leaks.[400] Clearly, while the leak rate for post-1923 pipe may be lower than pre-1924 pipe, the high volume of leaks in the 1924-1940 tranche is a sign of an aging asset and poses a significant risk of loss of containment.

Finally, TURN's reliance on RSE scores to defund this program is addressed in PG&E's Opening Brief.[401] TURN's proposal to focus on pre-1924 pipe, and not proactively replace 1924-1940 steel pipe would not mitigate the risk of significant incidents that could result from increasing volumes of aging pre-1940 pipe that will approach 100 years in-service or older.[402] It is to address these end-of-life risks that accompany aging assets, evidenced in part by the large volume of leaks being experienced, that PG&E has appropriately identified pre-1941 steel pipe for replacement. If TURN's proposal is adopted, PG&E will be required to depart from prudent steady-state asset management principles, and simply wait for failure of these assets as they age past their expected life span.

3.3.3.2 PG&E's Use of Its DIMP Model Is Appropriate

In compliance with federal regulations, PG&E evaluates pipe segments utilizing its Distribution Integrity Management Program or DIMP operational risk model. The model takes into consideration eight federal code required threats along with other factors affecting the pipe segment.[403] PG&E regularly reviews and updates the leak information for all pipe segments in its database and runs the model each year to determine the risk ranking of all pipeline segments.[404] The results of the 2020 DIMP risk evaluation are shown in the "2020 Distribution

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400 PG&E-16-E, p. 4-26, Table 4-4.

401 PG&E Opening Brief, p. 107.

402 PG&E Opening Brief, p. 106.

403 PG&E-16-E, p. 4-27, line 1-4.

404 PG&E-03, Gas Pipeline Replacement Program 2020 Annual Report, WP 4-169. PG&E has integrated the scope of the earlier GPRP risk evaluation program into the DIMP risk assessment tool to leverage the improved analytics and data capabilities which are being used to identify replacement scope for 2022. *Id*.

Risk Assessment and Recommendations for Mitigation Analyses" report (2020 Risk Assessment).[405] The 2020 Risk Assessment identified 2,300 miles of main distribution pipe as high risk.[406] This included 208 miles of pre-1941 steel pipe[407] and 494 miles of pre-1985 plastic pipe.[408] The remaining approximately 1,600 miles of high risk pipe is in later vintages of pipe.

TURN claims that "PG&E does not use its DIMP model to select the pipe for replacement under the GPRP" and that "the Commission should not be misled by PG&E's erroneous claims concerning the operational risk model"[409] are incorrect. As explained below PG&E's use of the DIMP model is appropriate.

3.3.3.2.1 The DIMP Model Should Be Used To Prioritize Pre-1941 Steel Pipe For Replacement

As explained above, the GPRP asset management scope includes replacement over time of all pre-1941 steel pipe before the pipe reaches its 100-year life. The GPRP focuses on reducing system risk by identifying and replacing those pipeline segments at greatest risk as identified by the risk model so as to provide the greatest impact on improving public safety. PG&E strives to replace the highest priority pipe first; however, operating conditions, construction economies of scale, city paving schedules, and third-party work occasionally favor pipe segments with lower priority values to be replaced prior to higher priority segments.[410] TURN states that it "has absolutely no objection to PG&E using the DIMP model to prioritize among the segments chosen for replacement" under the GPRP.[411]

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405 TURN-200, pp. 002-015.

406 TURN-200, p. 004, "2020 Distribution Assessment Recommendations for Mitigation Analysis".

407 TURN-201, PG&E Response to TURN 255-Q001.b.

408 TURN-200, p. 017, PG&E Response to TURN-081-Q02.h.

409 TURN Amended Opening Brief, pp. 161-162.

410 PG&E-03, Gas Pipeline Replacement Program 2020 Annual Report, WP 4-170.

411 TURN Amended Opening Brief, p. 162.

3.3.3.2.2 Post-1941 Steel Pipe Is Not Nearing Its Asset Life, And High Risk Segments Should Be Mitigated Under Existing Programs, Rather Than Being Proactively Replaced.

TURN claims that PG&E is not following the DIMP model for the approximately 1,600 miles of high-risk pipe post-1941 steel pipe and post-1985 plastic pipe identified by the 2020 Risk Assessment.[412] However, the fact that these newer pipe segments are not in the proactive plastic and steel replacement programs does not mean that the risk assessment is not used to guide mitigation activities for this pipe. Instead of proactive replacement, PG&E addresses this later vintage high risk pipe through its other risk mitigation programs.[413] Unlike pre-1941 steel pipe and the pre-1985 plastic pipe, all this pipe is still well within its expected asset life-span. The high risk scores under the DIMP model are therefore driven by factors other than vintage, and replacement due to age alone is generally not necessary. Other programs, including those driven by regulatory compliance requirements, are used to address these risks.[414]

3.3.3.3 The DIMP Model Is Dynamic And New High Risk Segments Continue To Be Identified Over Time

TURN recommends that PG&E should limit the replacement of 1923-1940 pipe to the 183 miles identified as high risk in the 2020 Risk Assessment. According to TURN, the 2020 Risk Assessment shows that the remaining 1,521 miles of 1924-1940 pipe should not be replaced since it is not high risk.[415]

This analysis is too simplistic and fails to recognize the dynamic nature of the risk assessment process. As discussed above, the 2020 Risk Assessment is merely a snapshot. PG&E regularly reviews and updates the leak information for all pipe segments in the pipe

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412 TURN Amended Opening Brief, pp. 161-162.

413 The process to identify and implement measures to address risk identified in the DIMP program is described in PG&E-03, WP 4-70 to WP 4-72, Utility Procedure TD-4850P-01, Rev. 3 (Dec. 16, 2020), Section 7.

414 These programs are described in in PG&E-03, WP 4-70 to WP 4-72, Utility Procedure TD-4850P-01, Rev. 3 (Dec. 16, 2020), Section 7.

415 TURN Amended Opening Brief, p. 163.

segment database and runs the model each year to determine the risk ranking of all pipeline segments. The fact that a candidate GPRP segment may not be identified as high risk in a given year does not mean that the pipe segment will not be included and scheduled for replacement in a subsequent year if the pipe condition or other factors change.[416] Thus, TURN's conclusion that the 2020 Risk Assessment shows that most 1924-1941 is not sufficiently high risk to warrant replacement is simply wrong.

For the same reason, TURN's observation that "PG&E's own risk analyses demonstrate that not all pre-1941 pipe presents a material risk of loss of containment"[417] is incorrect. While some GPRP pipe segments do not require immediate replacement, the regular review and updating of the data base and re-running of the model means pipe segments not requiring immediate replacement can become high priority in a future year.[418]

3.3.3.4 TURN's Proposal Will Dramatically Slow The Replacement Of All High Risk Vintage Pipe, Including Pre-1924 Steel Pipe

TURN proposes to slash this program by 60% and recommends that PG&E "focus on pre-24 pipe" and not proactively replace 1924-1941 steel pipe. However, TURN also agrees that its recommendations are not intended to limit PG&E to replacing pre-1924 pipe, acknowledging that PG&E should apply its DIMP risk model to replace the highest risk pipe with the funding it receives, even if that pipe is post-1923 pipe.[419] Thus, TURN recommends that PG&E should continue to replace the riskiest pipe based on its DIMP risk model regardless of the installation year of the pipe with a much lower funding level.[420]

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416 PG&E-03, Gas Pipeline Replacement Program 2020 Annual Report, WP 4-169. PG&E-03, WP 4-60 to WP 4-84, Utility Procedure TD-4850P-01, Rev. 3 (Dec. 16, 2020), describes the DIMP cycle of continuous updating and improvement.

417 TURN Amended Opening Brief, p. 158.

418 PG&E-03, GPRP 2020 Annual Progress Report, Section III, WP 4-169.

419 Tr. Vol. 13, 2447:8-15, TURN/Sugar.

420 PG&E Opening Brief, p. 103.

The net result of TURN's recommendation is that the pace of all high risk pre-1941 steel pipe replacement under the GPRP be slowed by 60%. This means less pre-1924 steel pipe will be replaced and less 1924-1941 steel pipe will be replaced.

The 2020 Risk Assessment identified 25 miles of pre-1924 steel pipe and 183 miles of 1924-1940 pipe, as high risk.[421] The DIMP risk model therefore indicates that substantially more post-1923 steel assets were high risk than the pre-1924 steel assets. While the percentage of projects going to each tranche would vary year-to-year based on the outputs of the DIMP risk model, using available funding to replace high risk pipe will result in a mix of projects both pre-1924 and post-1923, and all things being equal, could result in mostly post-1923 segments being replaced. Thus, cutting the funding of this program undercuts TURN's position that "[pre-1924] pipe should be replaced expeditiously" since the rate of replacement will be reduced by 60 percent compared to PG&E's program forecast.

For the same reasons, TURN's claim that it will only take 6 years to replace all pre-1924[422] pipe is incorrect. At 5 miles per year, the majority of the 5 miles would be likely utilized to mitigate post-1923 steel pipe, leaving very little to mitigate the pre-1924 pipe.

3.3.3.5 Contrary To Cal Advocates' Claim, PG&E Has Provided Ample Support For Its GPRP Request

In its Opening Brief, Cal Advocates reiterates arguments made in testimony. First, Cal Advocates claims "PG&E has not demonstrated it prioritizes replacement of the riskiest pipe."[423] This claim is simply wrong based on overwhelming evidence to the contrary in the record. In the 2020 GPRP Report that Cal Advocates refers to, PG&E explains:

> The GPRP's focus on reducing system risk by replacing segments with the highest relative risk (expressed by Priority Values), or pipeline integrity risks, is key to the Program's goal to identify and replace those pipeline segments at greatest risk so as to provide the greatest impact on improving public safety. . . .

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421 TURN-201, PG&E Response to TURN_255-Q001.c.

422 TURN Amended Opening Brief, p. 159.

423 Cal Advocates Opening Brief, p. 57.

> [¶] PG&E strives to replace the highest priority pipe first; however, operating conditions, construction scale of economies, city paving schedules, and third-party work occasionally favor pipe segments with lower priority values to be replaced prior to higher priority segments.[424]

Cal Advocates states that by not identifying the specific segments of pipelines that make up its 2023 request and to provide the Priority Value of each segment, PG&E does not "provide the Commission with the information it needs to ensure PG&E's excessive request prioritizes high-risk pipe."[425] However, as explained at length in PG&E's discovery responses, rebuttal testimony, and Opening Brief,[426] in October 2021, when Cal Advocates requested this information, PG&E had not fully completed its project development process for the GPRP, as defined in PG&E Utility Procedure TD-4802P-01 "Distribution Main Replacement Program Management," Section 2.1,[427] to determine an optimal book of work for 2023. Cal Advocates appears to fault PG&E for following its analytical work development processes. This is not a reasonable justification for a $37.6 million reduction.

For these reasons, the Commission should find that PG&E has supported its 2023 GPRP forecast and reject Cal Advocates' arguments.

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 on Distribution Mains and Services (DMS) installed before 1985 with Aldyl-A plastic and similar plastic materials. Plastic materials of pre-1985 vintage have a susceptibility to slow crack growth when exposed to stress, such as tree roots, differential settlement, or rock impingement. The Plastic Pipe Replacement Program prioritizes plastic main

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424 PG&E-03, Gas Pipeline Replacement Program 2020 Annual Report, WP 4-170.

425 Cal Advocates Opening Brief, p. 57.

426 PG&E Opening Brief, pp. 107-108.

427 PG&E-03, WP 4-96 to WP 4-98, Utility Procedure: TD-4802P-01, Rev. 0a (Dec. 18, 2019), Distribution Main Replacement Program Management.

replacement projects based on the relative risk of each pipe segment.[428] PG&E's unit forecast is to replace 170.4, 175.8, 181.1, and 186.5 miles in 2023, 2024, 2025, and 2026, respectively, for a total of approximately 714 miles. PG&E 2023 capital forecast is $522.3 million.[429]

TURN proposes a two-thirds reduction to PG&E's forecast recommending $171.6 million in 2023, limiting PG&E to replacing an average of 59 miles per year.[430]

Cal Advocates' proposed forecast reduction would allow replacement of 134.5 miles of pre-1985 plastic pipe in 2023 compared to PG&E's 170.4 mile forecast.[431]

AARP's proposed reduction maintains the program's funding at the average annual level that was approved in the 2020 GRC, which was $410.3 million for 139 miles of pre-1985 plastic main replacement per year.[432]

In the 2020 GRC, 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 these assets.[433] The Settling Parties included, among others, PG&E, Cal Advocates, the Office of Safety Advocate (OSA), TURN, and CUE. In this case, Cal Advocates and AARP each propose that PG&E be funded at or close to this currently approved level of pipe replacement, 139 miles per year. PG&E proposes to increase the rate to approximately 180 miles per year to ensure replacement of these assets before their predicted mean time to failure. TURN however, proposes a radical departure from the status quo pace, proposing to slash the program to replacement of a mere 59 miles of pipe per year.

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428 The Plastic Pipe Replacement Program is more fully discussed in PG&E's prepared testimony PG&E-03, p. 4-30, line 23 to p. 4-31, line 9.

429 PG&E Opening Brief, p. 109.

430 PG&E Opening Brief, p. 109.

431 PG&E Opening Brief, p.110.

432 PG&E Opening Brief, pp. 110-111.

433 2020 GRC Settlement Agreement adopted in the final GRC decision, D.20-12-005, Section 2.2.2.

The choice before the Commission boils down to whether the principle of steady state replacement 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. PG&E believes the choice is clear and urges the Commission to approve PG&E's proposed pace and funding for the plastic pipe replacement program.

Below, we respond to the arguments made by TURN,[434] Cal Advocates,[435] and AARP[436] in their Opening Briefs to support their respective positions.

3.3.4.1 1970 to 1983 Manufactured Pipe Exposed To Stress Is Expected To Fail Within 71 Years And Should Be Removed Before That Date

As explained in PG&E's Opening Brief, all pre-1985 Aldyl-A pipe is subject to cracking and should be removed before its expected failure date.[437] TURN claims that the primary concern is with certain plastic pipe manufactured from 1965 to 1972, and that pipe installed in 1976-1984 (manufactured from 1970 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.[438] Accordingly, TURN recommends that the plastic pipe replacement program can thus be reduced by two-thirds by focusing replacement on only the pre-1976 pipe and what TURN claims is the "small amount" of 1976-1984 installed pipe identified by PG&E's DIMP model.[439]

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434 TURN Amended Opening Brief, pp. 118-155, Section 3.3.1.

435 Cal Advocates Opening Brief, pp. 54-56, Section 3.3.2.

436 AARP Opening Brief, p. 17, Section 3.3.

437 PG&E Opening Brief, pp. 111-114, Section 3.3.4.1.

438 TURN Amended Opening Brief, pp. 119-120.

439 TURN Amended Opening Brief, p. 120.

TURN understates the risks of pipe manufactured from 1970-1983. This pipe is referred to in the 2014 CPUC Staff Report as "5043, non-LDIW" pipe.[440] The Staff Report estimates that for pipe manufactured from 1970 to 1983 that is stressed (e.g., by rock impingent), the pipe can be expected to fail due to crack development within 71 years (Medium Time To Failure, or MTTF).[441] The Staff Report concludes that the projected peak failure years for PG&E's installed pipe manufactured between 1970 and 1983 that is stressed are between 2050 and 2067.[442] PG&E's program is designed to proactively remove its vintage plastic pipes installed before 1985 before they reach the projected peak failure years.

The Staff Report found that abrupt and rapid failure can be expected (and has occurred) due to slow crack growth on Aldyl A pipe.[443] PG&E has 4,464 miles of plastic pipe manufactured between 1970 and 1983. The Staff Report assumes that this vintage pipe was installed in years 1970 to 1986.[444] All this pipe is potentially subject to rock impingement and other stresses that can cause slow crack growth and abrupt catastrophic failure. Given the 71 year Mean Time To Failure of this pipe when stressed, these failures could occur at any time over the next few decades unless the pipe is proactively replaced as PG&E proposes.[445]

Moreover, TURN's claim that "Aldyl-A pipe manufactured in 1971- 1983 … was ten times better in resisting slow crack growth" than earlier vintages[446] does not mean that stressed

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440 PG&E-03, WP 4-115, CPUC's Hazard Analysis & Mitigation Report on Aldyl A Polyethylene Gas Pipelines in California (June 11, 2014) (Staff Report), Table 1.

441 PG&E-03, Staff Report , WP 4-125, Table 4.

442 PG&E-03, Staff Report, WP 4-128, Table 7, last row. These failure dates are for pipe operated at 50 psi or greater that represents the operating condition of most of PG&E's plastic pipe. See Staff Report, WP 4-127, Table 6, Rows 4 and 5.

443 PG&E-03, Staff Report, WP 4-136.

444 PG&E-03, Staff Report p. 4-131. TURN-06-Atch1, PG&E's response to Data Request TURN_083-05(d), dated 1/21/22, p. 167.

445 PG&E Opening Brief, p. 113.

446 TURN Amended Opening Brief, p. 119.

pipe of this manufacturing vintage will not fail, but merely that it will take longer to fail.[447] The Staff Report states: "Aldyl-A pipes made of Alathon 5043 with LDIW characteristics have a median projected time to failure only 1/10th that of Aldyl A pipes made of Athalon 5043 resin that have no LDIW characteristics."[448] Thus, the Report does not find that 1970 – 1983 manufactured pipe will not fail when subjected to stress, but that crack growth will take ten times longer than certain earlier vintages. The Staff Report projects that when subject to stress, LDIW 5043 has a mean time to failure of 12 years, while non-LDIW 5043 has a mean time to failure of 71 years. Given this time to failure, the peak failure years for 1970-1983 pipe are still ahead and will occur from 2050 to 2067.[449]

TURN's argument that pipe installed after 1976 is not sufficiently high risk to replace proactively also fails because one third of all the replacement of pipe under this program to date has included pipe installed after 1976.[450] This is because PG&E's risk model, that ranks the riskiest segments of pipe, determined that those post-1976 pipe segments were higher risk that pre-76 pipe segments. TURN's claim that the tranche of post-1976 pipe does not warrant proactive replacement because there is insufficient risk is therefore incorrect.

TURN argues that a review of various technical documents supports its position that the risks associated with 1970-1983 5043, non-LDIW pipe are low. However, these technical documents all support PG&E's inclusion of pipe installed between 1976 and 1984 in its proactive replacement program.

<u>PHMSA's Advisory Bulletins.</u>[451] PHMSA issued four advisory bulletins between 1999 and 2007 warning of the potential for cracking in plastic pipe installed through the early

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447 This point is acknowledged by TURN. Tr. Vol. 13, 2479:15-20, TURN/Sugar.

448 PG&E-03, Staff Report, WP 4-114.

449 PG&E Opening Brief, p. 112, and fn. 470.

450 PG&E Opening Brief, p. 117-118, Section 3.3.4.4.

451 TURN Amended Opening Brief pp. 130-131.

1980s.[452] Advisory Bulletin ADB-02-07 found that "some of these older polyethylene pipes are more susceptible to brittle-like cracking" and identified certain products specifically.[453] ADB-07-01 added additional products to the list.[454] However, ADB-07-01 advises operators to "review the three earlier advisory bulletins on this issue." As noted above the earlier bulletins warn of the hazards associated with pipe installed through the early 1980s. Nowhere does PHMSA disavow this warning, but merely identifies specific products that are susceptible to cracking.

The JANA Report. TURN cites to the June 13, 2013 risk evaluation of PG&E's Aldyl A pipe performed by JANA Laboratories Inc. to claim that Aldyl-A Pipe manufactured before 1973 is higher risk that pipe manufactured after that date.[455] However, this report does not claim that post-1973 pipe is not at risk of failing due to crack-growth. As the Staff Report found, the post-1973 pipe if stressed will take longer to fail (71 years), but it is still subject to abrupt failure. TURN goes on to cite the JANA report for the proposition that the leak rate for post-1973 pipe is approximately 50% of that for the pre-1973 vintages.[456] However, leak rate is only one factor in determining the relative risk of pipe. A significant portion (one third) of Aldyl-A replacement has been of post-1973 pipe as indicated by PG&E's risk model that includes multiple risk factors along with leak rate.[457] In Section 3.3.4.2 below, PG&E further addresses the role of leak rate in pipe replacement.

The 2014 CPUC Staff Report. In its Opening Brief, PG&E summarized the key findings of the Staff Report that: (1) all vintages of plastic pipe manufactured prior to 1983 are

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452 These four advisories (ADB-99-01; ADB-99-02; ADB-02-07; and ADB-07-01) are found in PG&E's workpapers. PG&E-03, WP 4-99 to WP 4-106.

453 PG&E-03, WP 4-102.

454 PG&E-03, WP 4-106.

455 TURN Amended Opening Brief pp. 132-133.

456 TURN Amended Opening Brief, p. 132.

457 PG&E Opening Brief, pp. 117-118, Section 3.3.4.4.

susceptible to brittle-like cracking (by slow crack growth); (2) pipe manufactured from 1970 to 1983 that is stressed can be expected to fail due to crack development within 71 years and the projected peak failure years for PG&E's installed pipe of this is between 2050 and 2067; and (3) the danger associated with slow crack growth on Aldyl A is that although the failures develop slowly, when they do fail, they fail much more abruptly and rapidly than underground leaks on steel distribution pipes.

TURN down-plays these findings by noting that without being stressed, post-1973 pipe will last much longer than 71 years, and there is therefore "no need to start replacing this pipe without any additional indication of a problem due to external stress."[458] As discussed in Section 3.3.4.4 below, however, there is generally no practical way to know which specific pipe under the ground is subject to stress. PG&E already utilizes all pipe segment information available, including leak data, in its DIMP data base to determine whether pipes are high risk, but there is no magic method to identify stressed pipe. The Staff Report encourages operators to develop a pipeline risk management program that takes "into account all identified threats affecting pipeline safety in combination, rather than to treat each threat in isolation…."[459] PG&E's multi-factor DIMP risk assessment model is consistent with this guidance. With respect to 1970-1983 pipe, the Staff Report recommends:

> Operators should re-examine their risk assessment and mitigation strategies to ensure they will be replacing the at-risk pipes at a sufficient rate to mitigate the risk associated with LDIW Aldyl A pipes dues to squeeze-offs and to pre-1983 non-LDIW pipes due to rock impingement.

PG&E has followed this recommendation by adopting a rate of replacement sufficient to ensure replacement of this pipe prior to its expected mean time to failure of 71 years.

458 TURN Amended Opening Brief, p. 135.

459 PG&E-03, WP 4-139.

OSA 2020 GRC Testimony.[460] As explained in PG&E's Opening Brief, in the 2020 GRC OSA recommended that PG&E proactively replace a minimum of 139 miles per year of pre-1985 plastic pipe.[461] OSA based its recommendation on the findings of the 1998 NTSB report, the recommendations of the 2014 CPUC Staff Report, and OSA's finding that "[t]he potential danger posed by early vintage Aldyl-A and similar plastic pipes and the devasting impacts of their failures are well documented."[462] TURN claims that the OSA testimony "did not at all consider the risk profiles of different vintages of Aldyl-A pipelines in detail."[463] However, as PG&E has explained at length, the 2014 CPUC Staff report, on which OSA relied in part, does in fact support the conclusion that all pre-1985 installed plastic pipe is susceptible to slow crack growth and abrupt failure that justifies a program to remove that pipe before it fails catastrophically in service. TURN also states that "the OSA did not have access to the risk modeling conducted using the approved SMAP methodology."[464] However, there is no evidence that OSA would have revised its conclusion that is based numerous industry studies and reviews of the dangers of Aldyl-A pipe by the NTSB, PHMSA, and the CPUC's staff going back to at least 1998. The OSA's 2020 opinion that a minimum of 139 miles per year of pre-1985 Aldyl-A pipe should be replaced is still relevant and based on sound analysis.

The SPD 2020 RAMP Report. TURN claims that the SPD's response to PG&E's 2020 RAMP Report[465] somehow retracts or undermines the conclusions in the 2014 CPUC Staff Report.[466] The SPD response to the 2020 RAMP Report states that instead of PG&E's

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460 PG&E-54.

461 PG&E Opening Brief, p. 116.

462 PG&E-54, p. 4-6, lines 3-4.

463 TURN Amended Opening Brief, p. 140.

464 TURN Amended Opening Brief, 139.

465 PG&E-02, WP 1-43, lines 188 and 189.

466 TURN Amended Opening Brief p. 119; Tr. Vol. 13, 2472:19 to 2473:17, TURN/Sugar.

proactive replacement program "[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."[467] However, as TURN's witness John Sugar acknowledged, this recommendation in the RAMP report does not change the 2014 Staff Report's assessment of the failure risks of Aldyl-A pipe, the 71 year MTTF of that pipe, or the recommendations of the report.[468] Moreover, as recommended by the staff, PG&E is already using all information available to identify the highest risk pipe segments to prioritize the replacement of those segments.

3.3.4.2 Leak Rate Data Does Not Justify Ignoring The Risks Of Plastic Pipe Installed After 1975

TURN argues that PG&E's actual leak rate data is the primary risk metric and confirms the significantly lower risk posed by plastic pipe installed after 1975. According to TURN's analysis, the weighted average leak rate per mile of pipeline installed in 1965-1975 was twice the leak rate of pipe installed in 1976-1984.[469] TURN concludes "Aldyl-A pipeline installed in 1976 and later has a significantly lower loss of containment (i.e. leakage) risk than older Aldyl-A pipeline, and PG&E should focus its replacement efforts on plastic pipe installed pre-1976"[470]

Leak rate alone, however, does not determine the risk of given pipeline segment. PG&E's risk ranking is based on a methodology that considers leak history, pipe age, material type, ground temperature, diameter, operating pressure, and population proximity.[471] PG&E continues to use prior leak history as a qualifier for pipe replacement recommendations.[472] TURN's claim that the primary risk resides with pre-1976 plastic pipe is not well founded.

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467 See PG&E-02, WP 1-43, line 189.

468 Tr. Vol. 13, 2478:10-25, TURN/Sugar.

469 TURN Amended Opening Brief, p. 126.

470 TURN Amended Opening Brief, pp. 121-122.

471 PG&E Opening Brief, p. 118.

472 PG&E-16-E, PG&E's response to Data Request TURN_106-Q009a, dated 2/15/22, p. AppA-225.

While the leak rate for the two plastic pipe cohorts is different, in the 5-year period between 2016 and 2020, pre1976 plastic pipe experienced 717 leaks whereas 1976---1984 plastic pipe experienced 713 leaks.[473] The likelihood of a loss of containment clearly exists for 1976-1984 plastic pipe.

3.3.4.3 Past Incidents Are Not An Indicator Of Future Incidents Given The Approach Of Peak Failure Years For Pipe Installed After 1973

To further downplay the risks of 1970 -1983 plastic pipe, TURN states "all but one of the incidents on plastic pipes in California involved plastic pipe installed prior to 1976, and one involved pipe installed in 1977."[474] Given the 71-year mean time to failure or "MMTF" for slow cracks to develop in pipe installed after 1976, however, past incident history is not an indication of future failures. The 2014 CPUC Staff Report predicts that failures of pipes manufactured from 1970 to 1983 (and generally installed from 1970 to 1986) will continue for close to the next hundred years.[475]

3.3.4.4 It Is Generally Not Possible To Identify Installed Plastic Pipe That Is Subject To External Stress

TURN points out that without being stressed, post-1973 pipe will last much longer than 71 years, and there is therefore "no need to start replacing this pipe without any additional indication of a problem due to external stress."[476] TURN goes on to say "if PG&E has actual data demonstrating that certain pipelines installed after 1975 may be at risk for external stress that may hasten slow crack growth, then PG&E should absolutely use such data to identify high risk pipe for replacement. But such targeted replacement based on additional evidence is different from wholesale pre-emptive replacement of over 4,400 miles of 1976-1984 plastic

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473 PG&E-16-E, PG&E's response to Data Request TURN_048-Q01, dated 11/16/21 and TURN_048-Q01Atch01, pp. AppA-20 to AppA-62.

474 TURN Amended Opening Brief, p. 128.

475 PG&E-03, Staff Report, WP 4-131.

476 TURN Amended Opening Brief, p. 135.

pipe."[477] TURN faults PG&E for assuming that all plastic pipe is potentially subject to stress and failure, calling this approach "risk averse".[478] However, TURN's alternative seems to assume none of the pipe is stressed, and to simply wait for failures to occur.

The reality is, however, that with thousands of miles of buried pipe, there is generally no way to determine if a particular segment of pipe is or is not being subjected somewhere along its length to exposed to stress, such as tree roots, differential settlement, or rock impingement. PG&E has 4,464 miles of plastic pipe manufactured between 1970 and 1983. All this pipe is potentially subject to rock impingement and other stresses that can cause slow crack growth and abrupt catastrophic failure.[479] Given the 71 year Mean Time To Failure of this pipe when stressed, these failures could occur at any time over the next few decades unless the pipe is proactively replaced as PG&E proposes.

PG&E is already using all information available to identify the highest risk pipe segments to prioritize the replacement of those segments. Specifically, PG&E's DIMP risk model evaluates pipe segments based on pipe characteristics, such as vintage and type, and leak data for replacement consideration and other mitigation activities.[480] Neither TURN nor any other party has proposed a better way to determine the riskiest pipe.[481] Assuming that if a given segment has no leak history, it is therefore not subject to stress is not a prudent option given that failure due to crack development could be abrupt and without warning.

3.3.4.5 TURN's Proposal Will Dramatically Slow The Replacement Of All High Risk Plastic Pipe, Including Pre-1976 Installed Pipe

TURN proposes to slash this program by 66% and recommends that PG&E focus on pre-1976 plastic pipe and not proactively replace 1976-1985 installed pipe. However, TURN also

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477 TURN Amended Opening Brief, p. 122.

478 TURN Amended Opening Brief, p. 142.

479 PG&E Opening Brief, p. 113.

480 See PG&E-02, WP 1-43, line 189.

481 PG&E Opening Brief, p. 114.

agrees that its recommendations are not intended to limit PG&E to replacing post-1976 pipe, acknowledging that PG&E should apply its DIMP risk model to replace the highest risk pipe with the funding it receives, even if that pipe is post-1976 pipe.[482] Thus, TURN recommends that PG&E should continue to replace the riskiest pipe based on its DIMP risk model regardless of the installation year of the pipe with a much lower funding level.[483]

TURN claims that "based on a forecast of replacing approximately 60 miles, rather than 180 miles, of plastic pipe per year [PG&E can] replace all pre-1976 pipe before it is 100 year old." TURN's recommendation, however, will result in a <u>much slower</u> rate of replacement of pre-1976 pipe contrary to TURN' insistence that such pipe is high risk and in urgent need of replacement. Moreover, even if TURN's claim were accurate, 100 years is much longer than the expected life of pre-76 plastic pipe.

TURN's 100-year prediction for replacement of all pre-1976 pipe incorrectly assumes that all pipe replacement going forward will be pre-1976 pipe. However, since the inception of the program, 187 of the 570 miles of high-risk plastic pipe (one third) that have been deactivated has consisted of pipe installed from 1976 to 1984.[484] As agreed by TURN, going forward PG&E will continue to use its operational risk model, with all available pipe segment information, to prioritize pipe. If the assumption is made that a significant portion of high risk pipe will continue to be identified in the 1976-1985 installed years and will be replaced as indicated by the model, especially as that pipe continues to age, TURN's reduced program will

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482 Tr. Vol. 13, 2447:8-15, TURN/Sugar; TURN Amended Opening Brief, pp. 152-153 "However, as with any funding recommendation, PG&E has flexibility to modify the scope of work based on emerging priorities. TURN suggests that if PG&E finds that certain segments of the 1976-1984 pipeline have a higher risk priority based on the results of its DIMP modeling or field leak inspections PG&E should of course pursue replacing those pipelines" and p. 147 "TURN's proposal uses the DIMP model results in exactly the same way as PG&E, and TURN does not dispute that high risk segments of pipe should be replaced."

483 PG&E Opening Brief, pp. 104-105, Section 3.3.3.1.

484 TURN-06, pp. 175-178, PG&E's response to Data Request TURN_106-Q001, dated 2/15/22. The table shows total of 570.09 miles deactivated. 187 is the sum of deactivated main miles in installation years 1976 -1984.

extend the replacement of all plastic pipe, including pre-1976 pipe, well beyond TURN's claimed 100 year date. TURN's proposal guarantees that most remaining pipe that is subject to stress, including pre-1976 pipe that TURN claims is the highest risk, will simply fail in service, potentially with catastrophic results. Under PG&E's program, replacement of all pre-1985 plastic pipe (including pre-1976 installed pipe) will occur three times as quickly, greatly reducing the risks of cracking and loss of containment from pipe exceeding its expected life.

3.3.4.6 PG&E's Use Of Its DIMP Model Is Appropriate

In compliance with federal regulations, PG&E evaluates 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.[485] PG&E 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.[486] This methodology is used to select pre-1985 pipe segments to replace under the Plastic Pipe Replacement Program. TURN agrees, stating "TURN's proposal uses the DIMP model results in exactly the same way as PG&E, and TURN does not dispute that high risk segments of pipe should be replaced."[487]

The results of the 2020 DIMP risk evaluation are shown in the "2020 Distribution Risk Assessment and Recommendations for Mitigation Analyses" report (2020 Risk Assessment).[488] Based on the DIMP model, the 2020 Risk Assessment identified 2,300 miles of main distribution

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485 PG&E-16-E, p. 4-38, line 26-28.

486 PG&E-03, WP 4-60 to WP 4-84, Utility Procedure TD-4850P-01, Rev. 3 (Dec. 16, 2020) describes the DIMP cycle of continuous updating and improvement.

487 TURN Amended Opening Brief, p. 147.

488 TURN-200, pp. 002-015.

pipe as high risk.[489] This included 208 miles of pre-1941 steel pipe[490] and 494 miles of pre-1985 plastic pipe.[491] The remaining 1,600 miles of high risk pipe is in later vintages of pipe.

TURN claims that the 1985 cut-off date in PG&E's program is arbitrary and PG&E should be using the DIMP model's results to also replace post-1985 plastic pipe as indicated by the DIMP model ranking. TURN argues "[t]he fundamental question is why is PG&E prioritizing replacing all 6,400 miles of pre-1985 Aldyl-A pipe, of which only 494 miles were identified as highly risky by its DIMP model, rather than perhaps some of the 1,600 miles of pipe found to be higher risk ranking through its DIMP modeling? [¶] If PG&E truly believes that its DIMP model provides a risk-ranked output of pipeline segments, then it should be using the model for setting replacement priority for all of its pipeline segments, and to better tranche its thousands of miles of plastic pipe."[492]

However, PG&E's use of its DIMP model to address risky pipe of all vintages is prudent and appropriate. As explained above and recognized by the CPUC's 2014 Staff Report and other studies, 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. That is why pre-1985 pipe has been selected for proactive replacement, using the DIMP model to select the highest risk pipe for replacement in a given year. TURN agrees with this approach.

For plastic pipe installed after 1985, the fact that these newer pipe segments are not in the proactive plastic replacement program does not mean that the DIMP risk assessment is not used to guide mitigation activities for this pipe. Instead of proactive replacement, however, PG&E

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489 TURN-200, p. 004, "2020 Distribution Assessment Recommendations for Mitigation Analysis".

490 TURN-201, PG&E Response to TURN 255-Q001.b.

491 TURN-200, p. 017, PG&E Response to TURN-081-Q02.h.

492 TURN Amended Opening Brief , p. 150.

addresses this later vintage high risk pipe through its other risk mitigation programs.[493] Unlike the pre-1985 plastic pipe, all this pipe is still well within its expected asset life-span. The high risk scores under the DIMP model are therefore driven by factors other than vintage, and replacement due to age is generally not necessary (but may be justified in certain cases for compliance reasons). TURN's claim that PG&E is not consistently applying its DIMP model is therefore incorrect.

3.3.4.7 The DIMP Model Is Dynamic And New High Risk Segments Continue To Be Identified Over Time

TURN claims that "[t]he 2,309 miles identified by PG&E's DIMP model for potential mitigation work include a total of only 494 miles of pre-1985 Aldyl-A pipe, comprised of 208 miles of pre-1976 Aldyl-A pipe and 286 miles of Aldyl-A pipe installed in 1976-1984."[494]

This analysis is too simplistic and fails to recognize the dynamic nature of the risk assessment process.[495] PG&E regularly reviews and updates the DIMP model for all pipe segments in the pipe segment database and utilizes the model for its annual estimating cycle.[496] The fact that a candidate plastic pipe segment may not be identified as high risk in a given year does not mean that the pipe segment will not be included and scheduled for replacement in a subsequent year if the pipe condition or other factors change, and as pipe continues to be replaced. Thus, TURN's conclusion that "only 494 miles of pre-1985 Aldyl-A pipe, comprised of 208 miles of pre-1976 Aldyl-A pipe and 286 miles of Aldyl-A pipe installed in 1976-1984"

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493 The process to identify and implement measures to address risk identified in the DIMP program is described in PG&E-03, WP 4-70 to WP 4-72, Utility Procedure TD-4850P-01, Rev. 3 (Dec. 16, 2020), Section 7.

494 TURN Amended Opening Brief, p. 149.

495 The DIMP cycle, and the requirement that the program be continuously refreshed and improved, is described in PG&E-03, WP 4-61 to WP 4-63, Utility Procedure TD-4850P-01, Rev. 3 (Dec. 16, 2020), Section 1.2.

496 PG&E-03, WP 4-95 to WP 4-98, Utility procedure TP-4802-01, Rev. 0a (Dec. 18, 2019).

has been identified as high risk simply wrong given the regular updating of the program and reassessment of pipe as factors change and pipe ages.

3.3.4.8 A Low RSE Score Alone Does Not Justify The Dramatic Reductions Proposed By TURN

TURN claims "PG&E completely ignores the extremely low Risk Score Efficiency values of this program" and "the Risk Spend Efficiency of this program is less than 0.007, indicating an extremely low level of risk reduction per dollar spent."[497] First, contrary to TURN's claim that PG&E ignored RSE scores, PG&E considered RSE scores as part the prioritization process.[498] Second, as discussed in PG&E's Opening Brief, TURN's use of RSE scores to create benefit cost ratios is flawed, and use of RSE scores exclusively as the basis to cut programs that are justified for other operational reasons is not appropriate.[499]

TURN also claims that PG&E should have created two tranches of plastic pipe - based on the 1973 manufacture date cutoff – to separately calculate RSEs for at least two, if not more, tranches of plastic pipe installed before 1985.[500] PG&E addresses TURN's tranching arguments in its Opening Brief.[501]

3.3.4.9 The Risk Of Stranded Assets Should Not Prevent Replacement Of Pre-1985 Plastic Pipe

In its Opening Brief, PG&E responded to TURN's argument that drastically reducing spending on this program is justified because it could result in stranded investments due to decarbonization efforts and anticipated future gas through-put declines.[502] Specifically, PG&E believes such action is not warranted because: (1) a Commission adopted transition framework

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497 TURN Amended Opening Brief, pp. 118-119.

498 PG&E-03, p. 2-22, lines 5-8. See also Tr. Vol. 5, 881:18-20, PG&E/Kerans ("The RSEs that were within my chapter and within gas were reviewed in the calibration session.")

499 PG&E Opening Brief, p. 91, Section 3.2.2.2.

500 TURN Amended Opening Brief, p. 124.

501 PG&E Opening Brief, pp. 87-90, Section 3.2.2.1.

502 PG&E Opening Brief, pp. 119-122, Section 3.3.4.6.

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 that requires continued investment in the gas system despite any potential decline in throughput; and (3) PG&E's gas distribution mains (not services) would be the last to be deactivated in an electrification scenario once all downstream services on that main were converted to an alternative energy source. PG&E foresees a sufficiently long future for the gas mains due to a continued need to serve customers downstream of areas that may have been converted to an alternative energy source.

In its Opening Brief, TURN further states: "PG&E's stated goal is to replace about 6,400 miles of plastic pipe within the next 30 to 35 years. Such a massive replacement program would result in a total cost – and corresponding increase in PG&E's rate base – of over $20 billion. It is hard to imagine such additional utility investments not resulting in increased stranded costs if and when electrification of residential homes becomes a reality."[503] By speculating on gas capital expenditures over the next 35 years, TURN exaggerates the potential of the current GRC request to contribute to stranded costs. The Long-Term Gas System Planning Proceeding (R.20-01-007) is still developing policy guidance for the future of the gas system. For the purposes of the 2023-2026 GRC cycle, these concerns are premature: zonal electrification planning is still in the early stages and will not have a significant impact in this rate case.[504] Meanwhile, critical safety issues on the gas system must continue to be addressed.

3.3.4.10 Cal Advocates' Arguments

In its Opening Brief, Cal Advocates makes three arguments to support its recommendation to allow replacement of 134.5 miles of pre-1985 plastic pipe in 2023 compared to PG&E's 170.4 mile forecast.

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503 TURN Amended Opening Brief, p. 154.

504 PG&E-03, p. 1-16, lines 3-7.

First, Cal Advocates claims "PG&E's forecast is unreasonable based on its history of performance."[505] However, PG&E testified that even though miles replaced in 2020 were lower than expected due in part to COVID-19 related project delays, PG&E planned to complete the units funded in the 2020 GRC over the 2020-2022 period.[506] PG&E is now projecting that we will complete approximately 165 miles in 2022, or approximately 389 miles (93%) out of the 417 mile total over the 2020-2022 period. The remaining 28 miles targeted for 2022 are in planning and construction and are expected to become operational by April of 2023. While this year-end projection is not in the record, the approximately 165 miles PG&E is forecasting to complete in 2022 shows that PG&E has the capability of performing a higher annual mileage replacement rate than approved in the 2020 GRC and close to the 170.4 mile 2023 forecast. PG&E is also currently forecasting that its total spending on MAT 14D over the 2020-2022 period to complete the 389 miles by the end of 2022 will exceed the 2020 GRC imputed amount of $1,230,612,536.

Second, Cal Advocates claims that PG&E has not been able to identify an increase in the level of risk associated with the Plastic Pipeline Replacement Program compared to previous years.[507] This argument is wrong for two reasons. First, the risk of failure of Aldyl-A pipe due to slow crack development is a growing, time-dependent risk that requires a proactive response.[508] Second, PG&E identified recent regulatory bulletins that remind operators to "address the replacement or remediation of pipelines that are known to leak based on the

505 Cal Advocates Opening Brief, p. 54.

506 PG&E-16-E, p. 4-43, lines 13-19. PG&E completed 87 miles in 2020, which was a lower-than-expected number of units due to COVID-19 related project delays. PG&E completed 136.3 miles in 2021, and PG&E reaffirmed its plan to complete the balance of 193.3 miles by the end of 2022.

507 Cal Advocates Opening Brief, p. 55.

508 PG&E Opening Brief, pp. 114-115, Section 3.3.4.2.

material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history of the pipeline."[509]

Finally, Cal Advocates recommends a forecast based on PG&E's adjusted recorded 2021 expenditures for 2021 to 2023. In its Opening Brief, PG&E responds to this argument as being inconsistent with the rate case plan.[510] Furthermore, basing the 2022 forecast on 2021 would leave the planned 2022 work drastically underfunded given PG&E's plan to complete all 2020 GRC funded units.[511] As discussed above, PG&E now expects to complete approximately 165 miles in 2022, almost double the 87 miles completed in 2021.

3.3.4.11 AARP's Arguments

AARP proposes for this program the average annual level that was approved in the 2020 GRC, which was 139 miles of pre-1985 plastic main replacement per year, and less than PG&E's 2023 forecast of 170.4 miles. To support its recommendation, AARP raises four issues with PG&E's capital spending request.

First, AARP argues that PG&E's "targets are significantly higher than anything the Commission has deemed appropriate in the past."[512] However, as discussed in Section 3.3.4.1 above, PG&E's proposed pace is consistent with PG&E's asset management plan that is designed to ensure the long-term sustainability of assets.[513]

Second, AARP claims "the risk level presented by Aldyl-A plastic pipe has not changed since the Commission's last decision on the matter, nor have any new regulations or pronouncements on Aldyl-A plastic pipe been issued by relevant authorities."[514] PG&E

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509 PG&E Opening Brief, p. 115.

510 PG&E Opening Brief, pp. 122-123, Section 3.3.4.8 and p. 123 Section 3.3.4.9.

511 PG&E Opening Brief, p. 123, Section 3.3.4.9.

512 AARP Opening Brief, p. 17.

513 PG&E-16-E, p. 4-47, lines 8-19.

514 AARP Opening Brief, p. 17.

responds to this argument in Section 3.3.4.10 above in discussing similar claims by Cal Advocates.[515]

Third, AARP claims "undergrounding overhead electric lines reduces risk at a rate per dollar which is 843 times better than Aldyl-A plastic pipe replacement."[516] However, while the risk scores for many gas programs appear to be relatively lower than for other risks such as for Wildfire, PG&E disagrees that one can conclude that PG&E should not pursue these programs, as there continues to be risk in the gas system that requires ongoing mitigation and control programs to manage the risk.[517] As discussed in the rebuttal testimony of PG&E Witness Sumeet Singh,[518] PG&E's risk model development and RSEs are still evolving and such conclusions are premature.

3.3.5 Reliability Service Replacement Program – Capital

The Reliability Service Replacement Program proactively replaces gas services, including copper services, to improve system safety and maintain compliance with pipeline regulations. Examples of reliability service replacements are shallow services; corroded risers; bent risers and unsafe meter locations.[519] PG&E is forecasting 800 replacements in 2023 at a cost of $23 million. This includes 300 units forecasted for vintage services that were found in the field with incomplete records.[520]

TURN recommends that the scope of the work be reduced from 800 to 500 service replacements per year, resulting in a capital cost reduction of $8.231 million in the test year.[521]

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515 See also PG&E-16-E, p. 4-48, lines 12-20.

516 AARP Opening Brief, pp. 18-19.

517 PG&E-16-E, p. 3-6, lines 16-22.

518 PG&E-15-E, Ch. 1, Section C.4.

519 The Reliability Service Replacement Program (MAT 50B) is more fully discussed in PG&E's prepared testimony. PG&E-03, p. 4-33, line 25 to p. 4-34, line 7.

520 PG&E Opening Brief, pp. 124-125, Section 3.3.5.

521 TURN Amended Opening Brief, p. 166.

Cal Advocates recommends reducing PG&E's request to $10.210 million for 2023 consistent with the 2022 forecast and 2021 recorded figure. Cal Advocates claims that its recommendation would cover routine replacement of approximately 500 services but not replacement of 300 vintage services without records.[522]

Both TURN and Cal Advocates object to PG&E's forecast to replace 300 vintage services per year that do not have adequate records. Given the lack of material information for these vintage services, PG&E conservatively assumes these services were installed prior to 1985 and therefore, pose a loss of containment risk due to the possibility that they were constructed of materials with time-dependent risk, such as copper.[523] In addition, there is no evidence in the record that the lack of records for these vintage services was due in any way to non-compliance by PG&E with then-applicable record keeping requirements. It is prudent to replace these services given the risks.[524]

In addition, Cal Advocates recommends funding the program in 2023 using the 2022 forecast amount of $10.2 million arguing that this amount is reasonable because it is comparable to the 2020 recorded amount of $10.9 million. As PG&E argued in its Opening Brief,[525] this funding level would fund the replacement of only 372 services and not 492 services as Cal Advocates states.[526] The Commission should adopt PG&E's undisputed unit cost forecast of $27,435 in 2023 and provide sufficient funding for PG&E to perform the number of replacement units deemed appropriate by the Commission.

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522 Cal Advocates Opening Brief, p. 59-60.

523 PG&E-16-E, p. 4-56, lines 23-26.

524 PG&E Opening Brief, pp. 125-126, Section 3.3.5.1.

525 PG&E Opening Brief, p. 126, Section 3.3.5.2.

526 PG&E-16-E, p. 4-56, lines 14-20.

3.4 Asset Family – Transmission Pipe[527]

The Transmission Pipe asset family includes approximately 6,600 miles of natural gas pipelines and associated major components which transport gas from receipt points into PG&E's transmission pipeline system until the pipe arrives at a distribution center, storage facility, or large customer. In this section of our Reply Brief, we address the following issues regarding our gas transmission expense and capital expenditure forecasts raised by parties in their Opening Briefs:

TABLE 3-2
GAS TRANSMISSION DISPUTED ISSUES

Section	Topic	Parties
3.4.1	Traditional In-Line Inspection (ILI) Upgrades	TURN
3.4.2	ILI Assessments (Traditional and Non-Traditional)	TURN
3.4.3	ILI Assessments – DE&R Capital Repairs	TURN
3.4.4	Direct Assessments	TURN, Cal Advocates
3.4.5	Strength Testing and Replacement	TURN
3.4.6	Vintage Pipeline Replacement	TURN
3.4.7	Public Awareness Program	TURN
3.4.8	Shallow and Exposed Pipe (including Water and Levee Crossings)	TURN

Balancing and memorandum accounts related to gas transmission are addressed in Section 3.14.

3.4.1 Traditional ILI Upgrades – Capital (MAT 98C)

An In-Line Inspection or "ILI" Upgrade performs capital work on a gas transmission pipeline segment so that the pipeline segment can subsequently be inspected and assessed by traditional or non-traditional ILI tools. Without an ILI Upgrade, an ILI assessment cannot be performed.[528] As we demonstrated in our Opening Brief, many of the critical issues related to ILI Upgrades and ILI assessments are undisputed and all of these undisputed issues support

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527 Asset Family – Transmission Pipe is addressed in Chapters 5 and 5S of PG&E's Prepared Testimony, PG&E-03, and further addressed in Chapter 5 of PG&E's Rebuttal Testimony, PG&E-16-E.

528 PG&E Opening Brief, pp. 128-129.

PG&E's proposal.[529] PG&E's 2023 capital expenditure forecast for ILI Upgrades is $206.825 million.[530]

TURN is the only party in this proceeding that disputes PG&E's proposal for ILI Upgrades during the rate case period, arguing that the number of Traditional ILI Upgrades should be reduced from 12 to 4 projects per year and that the unit cost of these upgrades should be reduced as well. TURN's 2023 capital expenditure forecast for ILI Upgrades is $54.911 million.[531]

The number of Traditional ILI Upgrades and unit costs are addressed below in Sections 3.4.1.1 and 3.4.1.2, respectively. We then address TURN's argument regarding employee performance metrics related to ILI Upgrades in Section 3.4.1.3 and TURN's proposal for cost effectiveness review in Section 3.4.1.4.

3.4.1.1 The Number Of Traditional ILI Upgrades

As an initial matter, TURN recognizes that federal regulations <u>require</u> PG&E to perform pipeline assessments in High Consequence Areas (HCAs) every 7 years.[532] In addition, assessments are required every 10 years in Moderate Consequence Areas (MCAs) and Class 3 or Class 4 locations meeting certain criteria.[533] These federal regulatory requirements are not disputed. Rather, the issue is how these mandated assessments should be performed.

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529 PG&E Opening Brief, pp. 129-130.

530 PG&E Opening Brief, p. 132, Table 3-10 (showing 2023-2026 forecast).

531 TURN Amended Opening Brief, pp. xi-xii (describing reduction in PG&E's forecast).

532 TURN Amended Opening Brief, p. 177.

533 49 CFR §§ 192.3 and 192.710. In our Opening Brief, p. 128, we stated that re-assessments were performed every 7 years, but should have clarified that this was for HCAs. Later in our Opening Brief, p. 133, we explained that re-assessments were required every 7 years for HCAs and event 10 years for MCAs.

TURN acknowledges that there are essentially two kinds of assessment techniques that comply with federal regulations – ILI Assessments and Direct Assessments.[534] The question then becomes, which assessment method should PG&E use for specific pipeline segments. Where an ILI Upgrade has already been performed, the answer to that question is easy. An ILI assessment is the most comprehensive form of inspection and can be performed for less cost than Direct Assessment, and thus is the obvious choice as compared to Direct Assessment.[535] TURN does not dispute that where an ILI assessment can be performed because a pipeline has already been upgraded, that ILI is the assessment technique that should be used. However, on pipelines where an ILI Upgrade has not yet been performed, the question is whether an ILI Upgrade should be performed so that ILI assessments can occur or whether PG&E should instead perform Direct Assessments every 7 or 10 years in lieu of an ILI Upgrade.

TURN's answer to this question is that PG&E should continue to perform Direct Assessments on the majority of its pipelines and either not perform any ILI Upgrades at all during the rate case period or only perform 33% of the ILI upgrades recommended by PG&E.[536] Many of the arguments raised by TURN in its testimony and Opening Brief regarding ILI Upgrades were addressed in our Opening Brief.[537] However, there are two points raised by TURN in its Opening Brief that require a reply: (1) TURN's proposal to use RSE scores as the sole factor for determining whether PG&E should perform ILI Upgrades rather than considering all of the evidence and factors concerning safety and reliability; and (2) TURN's attempt to minimize California law and Commission decisions. These two issues are addressed below.

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534 TURN Amended Opening Brief, p. 177. Direct Assessment includes external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA), and stress corrosion cracking direct assessment (SCCDA).

535 PG&E Opening Brief, pp. 129-130 (explaining benefits of ILI assessments).

536 PG&E recommends 12 ILI Upgrades per year and TURN recommends 4 ILI Upgrades per year. See TURN Amended Opening Brief, p. 179.

537 PG&E Opening Brief, pp. 128-142 (addressing ILI Upgrade issues).

3.4.1.1.1 TURN's Narrow Focus On RSE Scores Is Flawed

TURN's argument against ILI Upgrades essentially comes down to a single factor – RSE scores. In its Opening Brief, TURN consistently returns to this theme.[538] There are several critical flaws in TURN's argument.

First, by focusing on RSE scores alone, TURN ignores the critical safety and operational benefits provided by ILI Assessments in comparison to Direct Assessments. These benefits are described in our Opening Brief.[539] TURN concedes, as it must, that the S-MAP Settlement expressly recognizes that in a GRC proceeding the utility can present evidence in addition to RSE scores to support a program.[540] As the S-MAP Settlement provides "[t]he utility is not bound to select its mitigation strategy based solely on RSE ranking" and "[m]itigation selection can be influenced by other factors including funding, labor resources, technology, planning and construction lead time, compliance requirements, and operational and execution considerations. In the GRC, the utility will explain whether and how any such factors affected the utility's mitigation selections."[541] In short, in a GRC, a utility can consider RSE scores and other factors and then explain in its submission the basis for its proposed mitigation strategy.[542] This is exactly what PG&E did for its ILI Upgrade proposal. While we provided the RSE scores for ILI Upgrades and ILI assessments, our Opening Testimony and Rebuttal Testimony included an extensive discussion of numerous other factors that affected our selection of ILI Upgrades as a mitigation strategy and the basis for our proposal to perform 12 ILI Upgrades per year.[543]

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538 TURN Amended Opening Brief, pp. 177-178, 180, 182-183.

539 PG&E Opening Brief, pp. 129-130, and 133.

540 TURN Amended Opening Brief, p. 70.

541 TURN-116, p. A-14, Row 26 (S-MAP Settlement Appendix).

542 These provisions in the S-MAP Settlement are discussed in more detail above in Section 2.3.1 of this Reply Brief.

543 PG&E-03, p. 5-20, line 14 to p. 5-35, line 4 (describing ILI Upgrades and ILI assessments); PG&E-16-E, p. 5-7, line 12 to p. 5-35, line 22 (addressing issues raised regarding ILI Upgrades and ILI assessments).

TURN's exclusive focus on RSE scores is inconsistent with the clear language of the S-MAP Settlement which expressly allows for consideration of other factors.

Second, TURN's argument focuses on one side of the coin, while ignoring the other side. As we explained in our Opening Brief, there are risk reduction benefits associated with ILI Upgrades and ILI assessments.[544] TURN does not dispute that ILI assessments have significant risk reduction benefits. Because an ILI assessment cannot be performed until a pipeline is upgraded, the risk reduction benefits of ILI Upgrades and ILI assessments must be considered together, something TURN fails to do. Instead, in its Opening Brief, TURN narrowly focuses on the RSE scores for ILI Upgrades.[545] As we acknowledged in updated discovery responses, at hearing, and in our Opening Brief, there were errors in our RSE calculations for ILI Upgrades and ILI assessments which will need to be corrected. These errors resulted in double counting some risk reduction benefits for ILI Upgrades and ILI assessments.[546] However, the impact of these correction will not change the fact that ILI assessments provide significant risk reduction value.

At the hearing, Mr. Tanguay explained in response to ALJ Larsen's questions that the original risk reduction values for ILI Upgrades and ILI assessments were 71 and 654, respectively.[547] Thus, the risk reduction benefits from ILI assessments are substantial. Mr. Tanguay also explained that as a result of the RSE calculation error, that at most there would be a reduction of 71 between the two programs to address the double counting.[548] If is the entire 71 was removed from the ILI assessments, these assessments would still have a risk reduction value of 583 and ILI Upgrades would have a risk score of 71. When the programs are

544 PG&E Opening Brief, pp. 136-137.

545 See e.g., TURN Amended Opening Brief, p. 177, Table 16 and p. 178, Table 17.

546 PG&E Opening Brief, pp. 137-138 (identifying discovery responses and hearing testimony).

547 Tr. Vol. 5, 810:11 to 811:27, PG&E/Tanguay.

548 Tr. Vol. 5, 811:19-27, PG&E/Tanguay.

considered together, it is obvious that there is substantial value for ILI Upgrades and assessments.

Comparing RSE scores is another way to look at this same issue. The uncorrected RSE scores for ILI Upgrades and ILI assessments are provided below as well as the RSE for Direct Assessments:

TABLE 3-3
ILI UPGRADE, ILI ASSESSMENT, AND DIRECT ASSESSMENT RSE SCORES

Program	RSE Score	Source
ILI Upgrades	0.08 (Uncorrected)	TURN-04, p. 8, Table 1
ILI Assessments	1.18 (Uncorrected)	PG&E-03, WP 3-11, Line 4[549]
Direct Assessments	0.09	TURN-04, p. 8, Table 1

We recognize, based on our discovery responses and testimony at hearing, that these RSE scores need to be corrected to: (1) include the additional benefits of ILI Upgrades; and (2) eliminate the double-counting between ILI Upgrades and ILI assessments.[550] While the ILI Upgrade and ILI assessment scores in Table 3-3 are not corrected for these errors, they do provide an order of magnitude of the difference between ILI Upgrade, ILI assessment, and Direct Assessment RSE scores. It is notable that the uncorrected RSE score for ILI assessments is substantially higher than Direct Assessments. If the ILI assessment score is corrected to address double counting, it would likely still be substantially higher than the Direct Assessment RSE score. Considering the ILI Upgrade and ILI assessment scores together highlights the risk reduction benefits as compared to Direct Assessments, which is the other option under federal regulations. As we explained above, to obtain the value of an ILI assessment, a pipeline must first have an ILI Upgrade. In short, ILI Upgrades should not be evaluated in isolation without considering the substantial benefits of ILI Assessments. This is something that TURN fails to do.

Third, in addition to the calculation errors identified, PG&E also explained in discovery and at the hearing that the RSE scores for ILI Upgrades did not consider certain ILI Upgrade

549 TURN did not provide the RSE for ILI assessments in Table 1 in TURN-04.

550 PG&E Opening Brief, pp. 137-138.

benefits.[551] Including these benefits will likely increase the RSE score for ILI Upgrades when the score is re-calculated, which further undercuts TURN's argument that the RSEs for ILI Upgrades are too low to justify the program.

Fourth, TURN argues that PG&E has already performed ILI Upgrades on 56% of its system and that the remaining pipeline segments are "low risk."[552] This argument, again, is based entirely on the RSE scores which, for the reasons explained above, should not be the sole criteria for ILI Upgrades. Moreover, as PG&E witness Barnes explained in rebuttal testimony, there is risk associated with the remaining 44% of PG&E's transmission system.[553] To plan its work on these remaining segments, PG&E uses its TIMP risk model to identify the highest risk remaining segments.[554] It is also notable that while approximately 56% of PG&E's transmission system will be piggable by the end of 2022, 67% of Sempra's system is currently piggable and nationally 70% of all operators' systems are piggable.[555] In other words, PG&E has a ways to go to make its system more consistent with industry averages.

Finally, TURN cites Mr. Barnes' testimony at hearing that an RSE analysis was a "reasonable starting point" to evaluate ILI Upgrades.[556] TURN again only gives the Commission one part of the story. On re-direct Mr. Barnes clarified his testimony and explained:

> Q I just have several questions for you, Mr. Barnes. The first is when you were being crossed by Mr. Long, and you were referring the RSEs, you referred to them as a starting point. Could you elaborate on what you meant by that?

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551 TURN-121, PG&E's response to Data Request TURN_226-Q002(a), dated 8/4/22; Tr. Vol. 5, 795:3-9; 801:11-802:2, PG&E/Tanguay.

552 TURN Amended Opening Brief, pp. 178-179.

553 PG&E-16-E, p. 5-14, line 28 to p. 5-15, line 3.

554 PG&E-16-E, p. 5-15, line 19 to p. 5-16, line 3.

555 PG&E-03, p. 5-27, Table 5-5.

556 TURN Amended Opening Brief, p. 182.

A Yes, what I meant by that is they are part of the process for -- for when we do our -- our budget assessments and budget allocations; and it's used along with several of the factors and -- and maybe starting point with misnomer in that what I really mean is we don't necessarily start there, it's just part of the overarching set of factors that we use.[557]

In other words, RSEs are one factor for consideration in the process of developing the GRC forecast. And consistent with Mr. Barnes' testimony, this is exactly what PG&E did in its prioritization process, using RSE scores as one of a number of factors considered.[558] TURN, on the other hand, only considers RSE scores and nothing else.

3.4.1.1.2 TURN's Attempt To Minimize Or Distinguish California Law And Commission Decisions Is Unavailing

Given its unmerited opposition to ILI Upgrades, TURN attempts to minimize or distinguish State law and Commission directives that encourage ILI Upgrades and assessments.[559] This issue was addressed in our Opening Brief.[560] TURN does raise several new arguments on this issue that merit a brief response.

First, Public Utilities Code Section 958(c) provides:

> At the completion of the implementation period [for a required pressure testing plan], all California natural gas intrastate transmission line segments shall meet all of the following:
>
> (1) Have been pressure tested.
>
> (2) Have traceable, verifiable, and complete records readily available.
>
> (3) Where warranted, be capable of accommodating in-line inspection devices.

TURN asserts that the phrase "where warranted" in Section 958(c)(3) gives the Commission discretion to consider a number of factors, including cost-effectiveness, when making decisions about ILI Upgrades.[561] We agree that this statutory language allows for consideration of a

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557 Tr. Vol. 5, p. 922:20 to 923:6, PG&E/Barnes.

558 PG&E-03, p. 2-22, lines 14-24.

559 TURN Amended Opening Brief, pp. 177, 181-182.

560 PG&E Opening Brief, pp. 135-136.

561 TURN Amended Opening Brief, p. 181.

number of factors including safety, ILI benefits, federal regulatory requirements, and cost-effectiveness related issues. The problem, however, is that TURN is focused on a single factor – RSE scores. As we explained in our Opening Brief, there are a significant number of factors supporting our ILI Upgrade proposal.[562] Had the Legislature intended to limit consideration to a single factor such as RSE scores or benefit-cost ratios, Section 958(c)(3) would have included language such as "Where warranted by benefit-cost ratios, be capable of accommodating in-line inspection devices." However, the Legislature did not limit consideration of ILI Upgrades to a single cost-effectiveness factor as TURN seeks to do. Based on all of the factors discussed in our testimony, PG&E's proposal is clearly "warranted."

Second, TURN asserts that our reference to D.20-05-037 is incorrect arguing that the underlying decision referenced by the Commission did not use the phrase "where feasible" and thus D.20-05-037 must have been incorrect when it used that language.[563] This is a curious argument. For context, D.20-05-037 addressed rehearing requests raised by a number of parties, including TURN, in PG&E's 2015 GT&S proceeding. On rehearing, TURN argued that the Commission had committed legal error because allegedly the authorized scope of work in the 2015 GT&S proceeding was not supported by substantial evidence.[564] The Commission rejected TURN's argument and explained that the work it had ordered in earlier decisions – including the modification of pipelines to allow for ILI assessments "where feasible" – supported the scope of work in the 2015 GT&S rate case.[565] As TURN notes, the underlying decision referred to by the Commission did not need to use the term "where feasible." However, in D.20-05-037, the Commission was simply explaining what it intended in the underlying decision and, in doing so, made clear that ILI Upgrades should occur where feasible. Under TURN's

562 PG&E Opening Brief, pp. 128-140.

563 TURN Amended Opening Brief, p. 181.

564 D.20-05-037, p. 11.

565 D.20-05-037, p. 12.

argument, the Commission could never clarify or explain its intent on rehearing using any words that were not in the underlying decision. This kind of constrictive reading of Commission decisions should be rejected.

Finally, TURN attempts to distinguish the Commission's recent decision adopting Safety Performance Metrics, including a metric specifically addressing Traditional ILI Upgrades.[566] TURN argues that the Commission did not consider RSEs in its decision. But this misses the point. The Commission made clear in D.21-11-009 that ILI Upgrades and the subsequent ILI assessments are an important safety mitigation and thus has encouraged the utilities to continue performing ILI Upgrades, which is exactly what PG&E proposes to do here.

3.4.1.2 ILI Upgrade Unit Costs

In addition to disagreeing about the number of ILI Upgrades that should be performed, PG&E and TURN also disagree about the unit cost for a Traditional ILI Upgrade. This disagreement centers around the issue of programmatic costs. Programmatic costs include costs incurred before and after a project becomes operational. For example, before PG&E performs construction on a project, it performs engineering work, obtains permits, and purchases land as needed. After a project is constructed and in operation, there may be additional costs such as re-paving a road or site remediation.[567] This latter category of costs, which occur after a project is operational, are referred to as carry-over costs because they "carry over" after a project is operational. Carry-over costs are a subset of programmatic costs which are all of the costs incurred before and after construction and operation.

In our Opening Brief, we described how TURN's proposed methodology, which uses a mixture of actual cost data and percentages and averages where cost data is not available,[568] is

566 TURN Amended Opening Brief, pp. 181-182.

567 PG&E-03, p. 5-34, line 16 to p. 5-35, line 4 (describing programmatic costs); PG&E-16-E, p. 5-20, lines 19-22 (defining carry over costs).

568 TURN Amended Opening Brief, p. 187 (describing use of actual data and estimates based on percentages for certain years).

less accurate than PG&E's approach which uses historic, actual costs as a proxy for programmatic costs for projects that went into operation between 2016 and 2019.[569] TURN's Opening Brief largely repeats its arguments from testimony, but there are several issues which require a brief reply.

First, using TURN's own methodology with more recent data demonstrates that a higher unit cost is appropriate. In Exhibit TURN-04, Attachment O, TURN attaches a PG&E data response which includes actual ILI Upgrade costs for projects that went into operation between 2016 and 2020. In its analysis, TURN uses 2016-2019 projects to determine a unit cost of $12.626 million in $2020.[570] However, if TURN applies its own carry-over cost percentages from Exhibit TURN-04, Table 3[571] to projects that went into operation in 2020, which TURN had the data to do, the unit cost for 2020 projects is $14.893 million in 2020 or almost 18% higher than TURN's unit cost forecast.[572] Thus, when more recent data is used in TURN's own methodology, it is evident that the unit costs should be higher than TURN proposes.

Second, TURN argues that PG&E uses percentages for its carry-over costs as well.[573] However, the workpaper referenced by TURN is not for the ILI Upgrade program, it concerns an entirely different program (*i.e.*, Vintage Pipe Replacement). For the ILI Upgrade unit costs, PG&E's approach using actual, historic data as a proxy is reasonable and more comprehensive than TURN's approach.

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569 PG&E Opening Brief, pp. 140-142.

570 TURN-04, p. 20, lines 7-25.

571 TURN-04, p. 19, Table 3.

572 TURN-04, Attachment O (using data for projects that went into operation in 2020).

573 TURN Amended Opening Brief, p. 189.

3.4.1.3 Employee Performance Metrics

TURN argues that ILI Upgrades should be removed as a performance metric for PG&E employees.[574] This argument was addressed in our Opening Brief.[575] To the extent PG&E performs ILI Upgrades, which even TURN acknowledges that 4 per year may be reasonable to perform, it is unclear why TURN would oppose including performance metrics related to this work in PG&E employee annual goals. It is also beyond the scope of this proceeding for TURN to dictate individual employee performance goals.

3.4.1.4 TURN's Ill-Defined Proposal Regarding Cost Effectiveness Review

Although TURN recommends 4 ILI Upgrades per year during the rate case period, it then qualifies this recommendation with a proposal that:

> Each Traditional ILI Upgrade project should be subject to scrutiny and demonstrated to be cost effective before it is completed. PG&E's proof should involve project specific examination of the RSEs and benefit cost ratios associated with the individual transmission pipelines that PG&E proposes to upgrade.[576]

Other than these two sentences, TURN provides no additional detail regarding its proposal. TURN's proposal raises numerous questions and thus should be summarily rejected.

TURN indicates that a project should be "subject to scrutiny" but does not explain what this means. For example, does this mean a formal Commission proceeding, a report, or some other kind of filing or submission. TURN is also unclear as to who will perform this "scrutiny."

TURN maintains that a demonstration of cost effectiveness must occur "before [an ILI Upgrade] is completed." Does this mean that a cost effectiveness evaluation should occur when a project is first proposed, in the early engineering stages, after engineering but before construction commences, or at some other undefined point? Depending on the venue where the "scrutiny" occurs, which is undefined in TURN's proposal, TURN's proposed timing could

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574 TURN Amended Opening Brief, p. 184.

575 PG&E Opening Brief, pp. 142-143.

576 TURN Amended Opening Brief, p. 179.

result in substantial delays. For example, a Commission application process typically takes more than a year. Under TURN's proposal, before PG&E even starts an ILI Upgrade, it would need to go through a potentially lengthy "scrutiny" process.

TURN proposes that PG&E's "proof" be project specific RSEs and benefit-cost ratios. However, ILI Upgrade RSEs have not been done at a project level. Moreover, it is unclear what RSE score would be sufficient to demonstrate cost-effectiveness.

TURN's proposal is short on details and will only result in additional delays and unnecessary process. This recommendation should be rejected.

3.4.2 ILI Assessments

Traditional ILI assessments occur when an inspection tool is moved through a pipeline driven by pressure differentials generated by gas flows. These assessments are performed in compliance with federal regulations and are intended to gather data about a pipeline to identify anomalies and determine the safe operating pressure of the pipeline.[577] PG&E forecasted $57.230 million in expense in 2023 for Traditional ILI assessments. TURN was the only party that disputed PG&E's Traditional ILI assessment forecast, arguing that the forecast should be reduced by more than 50% to $28.509 million.[578]

Non-Traditional ILI assessments occur when an ILI tool moves through the interior of a pipeline by means other than gas pressure differentials, such as robotic and tractor tools or winching with a cable. These assessments are also performed pursuant to federal regulation. PG&E forecasted $13.442 million in expense in 2023 for Non-Traditional ILI assessments. TURN was the only party that disputed PG&E's Non-Traditional ILI assessment forecast, arguing that the forecast should be $11.632 million.[579]

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577 PG&E-03, p. 5-24, lines 1-11.

578 TURN Amended Opening Brief, p. xii (reflecting TURN's proposed reduction).

579 TURN Amended Opening Brief, p. xii (reflecting TURN's proposed reduction).

In Section 3.4.2.1 below we address Traditional ILI assessments and in Section 3.4.2.2 we address Non-Traditional ILI assessments.

3.4.2.1 Traditional ILI Assessments – Expense (MAT HPB)

PG&E addressed Traditional ILI assessments in Section 3.4.1.4 of its Opening Brief.[580] With respect to Traditional ILI assessments (as referred to as ILI Inspections) which occur on a pipeline that is upgraded, TURN is the only party that disputes our forecast asserting: (1) the forecasted unit cost is too high; and (2) the forecasted number of Traditional ILI Assessments is too high.[581]

With regard to the unit cost, in our Rebuttal Testimony, we explained that TURN's regression analysis was flawed because it omitted <u>4</u> projects our of <u>25</u> total projects (*i.e.*, TURN failed to use 16% of the project data) and TURN also inappropriately removed outliers from the same analysis.[582] In its Opening Brief, TURN simply says it "used updated data and has systematically analyzed the best regression form for the data in each category."[583] This single sentence completely ignores PG&E's undisputed testimony that TURN's regression analysis only used 84% of the available data (without explanation) and inappropriately removed outliers. In short, TURN's Opening Brief fails to address the flaws in its own regression analysis which are essentially undisputed. TURN's analysis is also flawed because it used the carry-over cost analysis address above in Section 3.4.1.2. Given these flaws, TURN's proposal for unit costs for Traditional ILI Assessments should be rejected.

With regard to the number of Traditional ILI assessments, TURN focuses on two categories of assessments. First, TURN argues that 28 Traditional ILI assessments are associated with ILI Upgrade projects that are also forecast during the rate case period (2023-

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580 PG&E Opening Brief, pp. 143-145.

581 TURN Amended Opening Brief, pp. 190-195.

582 PG&E-16-E, p. 5-24, line 17 to p. 5-25, line 6.

583 TURN Amended Opening Brief, p. 191.

2026). Because TURN argues the ILI Upgrades should not be performed, the subsequent ILI Assessments are not necessary.[584] TURN's argument is based on the RSEs calculated for ILI Upgrades. The flaws with TURN's RSE arguments are addressed above in Section 3.4.1.1. On the issue of cost-effectiveness, TURN agrees that customers would save money from Traditional ILI assessments because these assessments are less expensive Direct Assessments but argues that the capital costs to perform an ILI Upgrade outweigh these savings.[585] However, over time, the costs of assessments will increase and the one-time capital investment associated with an ILI Upgrade will continue to benefit customers with lower ILI assessment costs. Moreover, customers will receive the reliability and safety benefits of ILI assessments described in Section 3.4.1.1 above. Finally, TURN does not dispute that there are additional benefits associated with ILI assessments, such as cleaning pipelines and other operational issues.[586] TURN simply asks for quantification, which can occur in future RSE analyses. But TURN does not dispute that these benefits exist for customers.

Finally, TURN argues that 23 Traditional ILI assessments which have compliance dates in 2027 can be delayed until the next GRC.[587] However, as we explained in our Opening Brief, given the federal regulatory compliance deadline associated with these assessments, and potential delays, TURN's "wait until the last minute" approach is neither reasonable nor prudent.[588]

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584 TURN Amended Opening Brief, pp. 192-194.

585 TURN Amended Opening Brief, pp. 193-194.

586 TURN Amended Opening Brief, p. 194.

587 TURN Amended Opening Brief, p. 195.

588 PG&E Opening Brief, p. 145.

3.4.2.2 Non-Traditional ILI Assessment – Expense (MAT HPR)

PG&E addressed Non-Traditional ILI assessments in Section 3.4.1.5 of its Opening Brief.[589] With respect to Non-Traditional ILI assessments, TURN is the only party that disputes PG&E's forecast and TURN's arguments are limited to unit costs. However, the undisputed evidence offered by PG&E demonstrates that TURN's analysis is flawed because it removed an "outlier" project from its calculation without a reasonable basis for doing so.[590] Notably, in its Opening Brief, TURN makes no effort to defend its removal of this project from its regression analysis. Instead, TURN simply makes a generic statement that it "used updated data and has systematically analyzed the best regression form for the data in each category."[591] This generic statement does not explain why TURN removed a specific project from its regression analysis nor does it remedy the flaws in TURN's analysis.

3.4.3 DE&R Associated With ILI Assessments

After an ILI assessment occurs, if specific anomalies in the pipe are identified, PG&E will conduct further evaluation and repairs as a mitigation, as required by federal regulations. This is referred to as direct examination and repair or "DE&R."[592] Costs for DE&R include expense (MAT HPI) and capital expenditures (MAT 75P). TURN and Cal Advocates dispute the expense forecast and TURN disputes the capital expenditure forecast. The expense and capital expenditure forecasts are addressed below.

3.4.3.1 DE&R – Expense (MAT HPI)

PG&E's forecast for DE&R expense for 2023 is $71.464 million.[593] TURN acknowledges that it made an error in its forecast and, correcting for that error, argues that the

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589 PG&E Opening Brief, p. 146.

590 PG&E-16-E, p. 5-32, lines 5-17.

591 TURN Amended Opening Brief, p. 191.

592 PG&E Opening Brief, pp. 146-147.

593 PG&E Opening Brief, p. 148, Table 3-15.

expense forecast for 2023 should be $48.973 million.[594] TURN's proposed reduction is based on a lower unit cost and a lower number of DE&R as a result of the lower number of ILI assessments proposed by TURN. Cal Advocates disputes PG&E's forecast based on the number of DE&R digs and recommends a 2023 expense forecast of $32.048 million.[595]

On the issue of unit costs, TURN argues that its regression analysis, which includes an additional year of data, is more appropriate for determining the DE&R unit costs. However, as PG&E demonstrated in testimony, TURN's regression analysis is less accurate based on R-squared values.[596] TURN also argues that PG&E's use of 2016 data skews the average because DE&R costs have been "trending downward markedly since 2016."[597] However, for MAT HPI, PG&E did not use 2016 data. Instead, PG&E used 2017-2019 data.[598] Thus, TURN's concerns about the use of 2016 data are misplaced. Given the greater accuracy of PG&E's forecast and TURN's acknowledged error, PG&E's unit cost forecast for MAT HPI should be used.

As to the amount of DE&R work required, TURN's argument is based solely on its assertion that fewer ILI Upgrades and ILI assessments should be performed.[599] This argument is addressed above in Sections 3.4.1.1 and 3.4.2.1.

Cal Advocates recommends that PG&E's forecast be reduced to the 2020 actual costs.[600] Cal Advocates maintains that because the 2023 ILI Upgrade and ILI assessment costs are forecasted to be lower than 2020 actual costs, DE&R costs should be lower as well.[601]

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594 TURN Amended Opening Brief, p. 197.

595 Cal Advocates Opening Brief, p. 63.

596 PG&E-16-E, p. 5-34, line 27 to p. 5-35, line 13.

597 TURN Amended Opening Brief, p. 198.

598 PG&E-03, p. 5-32, lines 13-15.

599 TURN Amended Opening Brief, p. 199.

600 Cal Advocates Opening Brief, p. 61.

601 Cal Advocates Opening Brief, p. 62.

However, Cal Advocates does not dispute PG&E's testimony explaining the basis for its DE&R forecast.[602] And although DE&R follows ILI Upgrades and ILI assessments, just because ILI Upgrades are forecasted in 2023 to be lower than 2020 actual costs does not mean DE&R, which is an entirely separate program, should also be lower than 2020 actual costs. The DE&R program work is separate and distinct from ILI Upgrades and thus it is entirely reasonable that costs for one program may decrease while costs for another program may increase.

As we explained in our Opening Brief, we are forecasting increased DE&R expense costs in 2023 because we are planning to perform more miles of ILI assessments.[603] DE&R projects are initiated when an anomaly is found during an ILI assessment. The more miles of ILI assessments that occur, the more anomalies that will likely be found and thus the more DE&R work to be performed. The undisputed evidence demonstrates that in 2022, PG&E is performing more miles of ILI assessments than it did in previous years, and thus there will be more DE&R projects in 2023 resulting in an increased expense forecast.[604] Cal Advocates argues that PG&E has "failed to justify" its forecast, but this argument is belied by PG&E's Prepared and Rebuttal Testimony and workpapers which provide sufficient evidence to support PG&E's forecast.[605]

3.4.3.2 DE&R – Capital (MAT 75P)

PG&E's forecast for DE&R capital expenditures for 2023 is $15.004 million. TURN proposes a forecast of $12.597 million based on a lower unit cost.[606] TURN's unit costs are based on 2016-2020 data rather than the 2017-2019 data used by PG&E. However, as PG&E explained in its Opening Brief, the recorded capital costs for 2016 were abnormally low

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602 PG&E-03, p. 5-32, lines 13-19.

603 PG&E Opening Brief, p. 148.

604 PG&E-16-E, p. 5-33, lines 12-18. Note that DE&R projects lag one year behind assessments, so ILI assessments that occur in 2022 will result in DE&R projects in 2023.

605 PG&E-16-E, p. 5-33, lines 12-23; PG&E-03-E, WP 5-15; PG&E-03, p. 5-32, lines 13-18.

606 PG&E Opening Brief, pp. 146-147 and Table 3-14.

compared to later years because in the later years PG&E has been using more technologically advanced inspection tools.[607] TURN's proposed reduction is based on outdated data using an earlier generation of technology (*i.e.,* 2016) and thus should be rejected.

3.4.4 Direct Assessments

In addition to Traditional and Non-Traditional ILI, Direct Assessment is another method for conducting pipeline integrity assessments. There are four types of Direct Assessment – external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA), stress corrosion cracking direct assessment (SCCDA), and direct examination. Parties dispute some, but not all, of PG&E's forecasts for the various types of Direct Assessment. The disputed Direct Assessment forecasts are discussed below.

3.4.4.1 ICDA Engineering And Digs/Direct Examinations – Expense (MATs HPJ And HPO)

Internal Corrosion Direct Assessment or "ICDA" identifies and assesses locations on a gas transmission pipeline where internal corrosion is likely.[608] ICDA work includes expense costs for engineering (MAT HPJ) and ICDA digs/direct examinations (MAT HPO).[609]

PG&E's forecast for ICDA engineering (MAT HPJ) for 2023 is $812,000.[610] TURN recommends reducing this 2023 forecast to $671,000.[611]

PG&E's forecast for ICDA digs (MAT HPO) is $12.9 million for 2023.[612] TURN recommends reducing the 2023 forecast to $11.829 million.[613] Cal Advocates does not oppose

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607 PG&E Opening Brief, p. 147.

608 PG&E-03, p. 5-38, lines 12-14.

609 PG&E-03, p. 5-43, lines 9-31.

610 PG&E Opening Brief, p. 153, Table 3-18.

611 TURN Amended Opening Brief, p. 200. TURN's Opening Brief also discusses ICDA costs also includes MAT 34A which is related to StanPac. ICDA costs associated with StanPac are addressed in Section 3.12.5 below.

612 PG&E Opening Brief, p. 154, Table 3-19.

613 TURN Amended Opening Brief, p. 200.

PG&E's forecast for ICDA digs but recommends that the ICDA dig costs be tracked in a memorandum account rather than recovered through the GRC revenue requirement.[614] We address Cal Advocates' argument in Section 3.14.3.2 below in the context of the ICDA memorandum Account (ICDAMA).

TURN's proposals to reduce the ICDA engineering and digs forecasts are both based on its use 2014-2019 data to establish unit cost forecasts. However, as we explained in our Opening Brief, PG&E's ICDA procedures substantially changed after 2016 and thus pre-2017 data is unreasonably low and does not reflect the costs associated with current ICDA procedures.[615] TURN does not dispute that PG&E's procedures changed after 2016, but only notes that PG&E relies on a narrow "set of projects."[616] PG&E relied on more than three years of data (2017-2019) as the basis for its forecasted unit costs.[617] TURN does not explain why three years of data is insufficient. Moreover, the three years of data relied on by PG&E reflect the current procedures and thus is an apples-to-apples comparison, while the extra years added by TURN (*i.e.*, 2014-2016) reflect earlier, less stringent procedures which resulted in lower costs during the earlier period.

TURN also ignores the fact that ICDA dig costs will likely increase substantially as a result of a PHMSA interpretation issued in June 2021. As PG&E witness Bennie Barnes explained in rebuttal testimony:

> [A] new PHSMA interpretation that was provided on June 23, 2021 will increase IDCA dig costs as compared to prior years. This resulted in an increase in the forecast of MAT HPO from $7.5 million for 2023 to $13.4 million.[618]

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614 Cal Advocates Opening Brief, pp. 71-72.

615 PG&E Opening Brief, pp. 152-156.

616 TURN Amended Opening Brief, p. 200.

617 PG&E-16-E, p. 5-43, lines 13-17.

618 PG&E-16-E, p. 5-45, lines 24-27 (footnotes omitted).

TURN fails to explain or even address how its unit cost calculation accounts for this recent change in PHMSA interpretation.

In addition to problems with the 2014-2019 data used by TURN, PG&E also explained in detail the flaws with the escalation factor that TURN uses for its ICDA engineering and dig forecasts.[619] While TURN argues that it does not agree that its escalation factor is flawed, it offers no explanation as to why its escalation factor is correct and implicitly concedes that flaws exist by suggesting that the Commission direct PG&E to apply its escalation factors to TURN's data set.[620] Given the flaws in TURN's data set (*i.e.*, data from 2014-2019) and its admittedly flawed escalation factor, TURN's proposed forecasts for ICDA engineering and digs should be rejected.

Finally, in its testimony, Cal Advocates raised a number of issues regarding ICDA cost data, including questions regarding the reason for the increase in PG&E's 2023 ICDA forecast as compared to recorded ICDA costs.[621] We addressed these arguments in our Rebuttal Testimony and Opening Brief.[622] Because Cal Advocates did not raise these issues in its Opening Brief, Cal Advocates appears to implicitly acknowledge that its concerns have been addressed.[623] Thus, the only remaining ICDA-related proposal in Cal Advocates' Opening Brief is that ICDA costs continue to be tracked in the ICDAMA rather than recovered through the GRC revenue requirement. This issue is addressed below in Section 3.14.3.2.

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619 PG&E-16-E, p. 5-38, lines 8-28 (discussing escalation factor in relation to ECDA); p. 5-43, lines 24-25 (explaining that same escalation factor error applies to ICDA).

620 TURN Amended Opening Brief, p. 200.

621 CALPA-02, p. 29, line 7 to p. 30, line 17.

622 PG&E-16-E, p. 5-45, line 10 to p. 5-46, line 17; PG&E Opening Brief, pp. 154-155.

623 Cal Advocates Opening Brief, p. 121.

3.4.4.2 ECDA Indirect Inspections -- Expense (MAT HPC)

ECDA indirect inspections (MAT HPC) involve diagnostic testing to assess the threat of external corrosion on a pipeline.[624] PG&E's 2023 forecast for ECDA indirect inspections was $8.108 million. TURN proposes a reduced forecast of $6.895 million.[625] TURN's proposed reduction is based on a reduced unit cost using 2014-2019 data.[626] This is the same unit cost approach that TURN used for ICDA costs. TURN also uses flawed escalation factors.[627] For the reasons explained above in Section 3.4.4.1 with regard to the use of 2014-2019 data and the flawed escalation factors, TURN's proposed reduction should be rejected.

3.4.4.3 ECDA Direct Examination -- Expense (MAT HPN)

After an ECDA inspection occurs, 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 (MAT HPN) is $34.394 million.[628]

TURN recommends an ECDA forecast of $34.712 million, which is higher than PG&E's forecast.[629] This is likely because PG&E adjusted its forecast in August 2022 to account for certain escalation errors, as described in PG&E's Rebuttal Testimony.[630] TURN's substantive arguments regarding the ECDA direct examination forecast are based on the use of 2014-2019 data.[631] PG&E addresses the flaws with TURN's 2014-2019 data set, as well as the erroneous

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624 PG&E Opening Brief, p. 150.

625 TURN Amended Opening Brief, p. 201. In its Opening Brief, TURN inadvertently transposed MATs HPN and HPC. PG&E understands that TURN is recommending $6.895 million for MAT HPC and $34.713 million for MAT HPN.

626 TURN Amended Opening Brief, p. 201.

627 PG&E-16-E, p. 5-38, lines 8-28.

628 PG&E Opening Brief, p. 151, Table 3-17.

629 TURN Amended Opening Brief, p. 201.

630 PG&E-16-E, p. 2-1, line 25 to p. 2-2, line 30.

631 TURN Amended Opening Brief, p. 201.

escalation factor used by TURN, in Section 3.4.4.1 above. For the reasons explained above, TURN's proposed forecast should be rejected.

Cal Advocates also addresses the ECDA direct examination program and recommends a 2023 forecast of $14.675 million.[632] Cal Advocates' proposed forecast reduction is based on the number of digs that PG&E will perform as a part of the ECDA direct examination. PG&E is forecasting to perform 168 digs in 2023 while Cal Advocates only forecasts 75 digs.[633]

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 applying a series of factors to each of these inspections to determine the estimated number of digs.[634] The factors reflect the number of digs identified in current PG&E procedures.

Cal Advocates points out several situations in earlier years where PG&E performed fewer digs than its procedures require.[635] However, this is not true for every ECDA project, only a small subset. Moreover, PG&E's forecast going forward correctly anticipates that the current procedures will be used to determine the appropriate number of ECDA digs.

Cal Advocates also points to testimony from the 2019 GT&S rate case and argues that the methodology PG&E used to determine the number of digs in that rate case is different than the methodology PG&E is using in this proceeding.[636] Cal Advocates quotes Mr. Barnes' testimony at hearing on this issue, but does not include the portion of Mr. Barnes' testimony where he explained that there were changes in PG&E's methodology from the 2019 GT&S rate case to this proceeding.[637] Mr. Barnes also explained that PG&E has included an additional

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632 Cal Advocates Opening Brief, p. 64.

633 Cal Advocates Opening Brief, pp. 63-64.

634 PG&E Opening Brief, p. 152; PG&E-16-E, p. 5-40, lines 20-31.

635 Cal Advocates Opening Brief, pp. 64-65.

636 Cal Advocates Opening Brief, pp. 65-66.

637 Tr. Vol. 5, 919:6-10, PG&E/Barnes.

threat identification for selective seam weld corrosion into the factors it considers for determining the appropriate number of digs.[638] Cal Advocates does not assert that the change in PG&E's revised methodology is unreasonable or offer any evidence that the revised methodology should not be used for the forecast in this proceeding.

Cal Advocates argues that, rather than using PG&E's procedures to estimate the number of digs, data from completed 2021 projects should be used and, for those projects, the numbers of miles surveyed should be divided by the number of digs to determine a dig per mile ratio.[639] This assumes that projects will generally be the same in terms of number of digs per mile. However, as Mr. Barnes explained in Rebuttal Testimony, the number of digs can vary substantially based on project specific conditions.[640] As Mr. Barnes concluded:

> PG&E did not propose nor utilize a simple dig rate to calculate the forecasted digs. Notably, Cal Advocates does not dispute PG&E's methodology, nor does Cal Advocates assert that any of the project specific estimates in PG&E's workpapers are incorrect. Contrary to Cal Advocates' assertion, PG&E has offered more than sufficient proof of its proposed dig rate, providing project by project estimates.[641]

3.4.4.4 SCCDA Engineering And Survey -- Expense (MAT HPK)

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. PG&E's 2023 forecast for SCCDA engineering and survey expense (MAT HPK) is $1.971 million.[642]

TURN proposes reducing SCCDA unit costs and thus its 2023 forecast is $1.630 million.[643] TURN's proposed unit cost reduction is based on the same methodology it used for

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638 Tr. Vol. 5, 920:6-23, PG&E/Barnes.

639 Cal Advocates Opening Brief, p. 66.

640 PG&E-16-E, p. 5-41, lines 1-20 (providing specific examples of different pipeline segments).

641 PG&E-16-E, p. 5-41, lines 21-27.

642 PG&E Opening Brief, p. 156, Table 3-20.

643 TURN Amended Opening Brief, p. 202.

forecasting ECDA unit costs.[644] The flaws with this methodology (*i.e.*, the use of 2014-2019 data and flawed escalation factors) are discussed above in Sections 3.4.4.1 and 3.4.4.3 above.

Cal Advocates proposes a reduction in the SCCDA engineering and survey 2023 forecast to $49,603 – a reduction of more than 97%.[645] Cal Advocates incorrectly argues that PG&E failed to provide sufficient evidence to support its forecast. To support this claim, Cal Advocates points to a single data response that asked how PG&E determined the total SCDDA engineering and survey distance of 15.87 miles for 2023. We addressed this assertion in our Opening Brief.[646] As we explained in Rebuttal Testimony:

> Cal Advocates requested PG&E to provide "all calculations and workpapers to support" PG&E's estimate for performing SCCDA Engineering/Survey on [15.87] miles. PG&E's response pointed Cal Advocates to the 2023-2026 scope provided in our workpapers and explained how PG&E calculated the number of miles for 2023. Notably, Cal Advocates fails to point to any deficiency or shortcoming in PG&E's detailed workpapers.[647]

In our workpapers, we identified every project that we intend to perform during the rate case period and the exact mileage of the project.[648] As we explained to Cal Advocates in our data response, the estimated 15.87 miles for 2023 is based on the cumulative mileage of the specific projects identified in PG&E-03, WP 5-22 and 5-23. Thus, we were fully responsive to Cal Advocates' request as to how the total mileage of 15.87 miles was calculated by providing an exact breakdown, by project, of the mileage that added up to 15.87. Cal Advocates' claim that PG&E failed to provide "basic information" is unsupported by the facts.

To develop its forecast for SCCDA engineering and surveys, Cal Advocates relied on 11 months of data from 2021.[649] However, the 2021 data only reflects two (2) SCCDA projects.

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644 TURN Amended Opening Brief, p. 202; PG&E-16-E, p. 5-48, lines 13-18.

645 Cal Advocates Opening Brief, p. 67.

646 PG&E Opening Brief, p. 157.

647 PG&E-16-E, p. 5-49, lines 3-9 (footnotes omitted).

648 PG&E-3-E, WP 5-22 to WP 5-23.

649 Cal Advocates Opening Brief, p. 68.

In this rate case, PG&E is proposing 19 SCCDA projects a year and our workpapers identify the specific projects we intend to undertake. In our Rebuttal Testimony, we explained that the reason why the forecast for SCCDA engineering and surveys was substantially higher during the rate case period (2023-2026) is because of upcoming regulatory compliance deadlines which did not exist in 2021:

> Cal Advocates' proposal ignores the number of projects necessary to meet Subpart O assessment requirements for the SCC threat. PG&E's SCCDA workpaper shows that there are 77 SCCDA projects with compliance due dates within the rate case period, an average of more than 19 projects a year. Cal Advocates' proposal to use 2021 as a basis where there were only two SCCDA projects required for assessment under Subpart O falls very short of the 19 SCCDA projects that PG&E is required to do under Subpart O, and is therefore without merit.[650]

Cal Advocates does not dispute these compliance deadlines which occur during the rate case period. Given the substantial expansion in SCCDA projects during the rate case period required by compliance deadlines, it is entirely reasonable that PG&E's cost forecast would be substantially higher than the 2021 actual costs.[651]

3.4.4.5 SCCDA Digs – Expense (MAT HPP)

SCCDA digs involve excavating and exposing pipeline segments in selected locations based on the SCCDA engineering analysis. PG&E's 2023 forecast for SCCDA digs (MAT HPP) is $16.208 million.[652]

TURN proposes reducing the SCCDA digs 2023 forecast to $15.91 million based on the same unit cost methodology it used for ECDA.[653] The flaws with TURN's methodology (*i.e.*, the use of 2014-2019 data and flawed escalation factors) are discussed above in Sections 3.4.4.1 and 3.4.4.3 above.

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650 PG&E-16-E, p. 5-49, lines 22-29.

651 PG&E Opening Brief, p. 157.

652 PG&E Opening Brief, pp. 157-158 and Table 3-21.

653 TURN Amended Opening Brief, p. 202.

Cal Advocates proposes a drastic reduction in the SCCDA dig 2023 forecast to $897,765 – a reduction of approximately 94%.[654] Cal Advocates makes the same argument for SCCDA digs that it did for SCCDA engineering and surveys, asserting that PG&E failed to provide sufficient evidence to support its request.[655] However, as PG&E explained in Rebuttal Testimony, its workpapers identified each project where a stress corrosion cracking threat had been identified and was proposed to be addressed in the rate case period:

> PG&E's workpapers provided specific SCCDA projects and estimated number of digs that PG&E proposed to perform during the 2023-2026 rate case period. As PG&E explained to Cal Advocates in discovery, "Stress Corrosion Cracking Direct Assessment (SCCDA) is being forecast because there exists a Stress Corrosion Cracking (SCC) threat that is due for threat assessment within the rate case period as a result of requirements of 49 CFR Part 192, Subpart O." In other words, each of the projects identified has a SCC threat that needs to be addressed during the rate case period.[656]

It is unclear what additional information Cal Advocates needed. The identification of project specific work, including project location, mileage, type of SCC threat, and the compliance due date is more than sufficient to demonstrate the reasonableness of PG&E's forecast. In addition to identifying specific projects that are the "units" for PG&E's forecast, our workpapers also explain that the unit cost forecast was developed using the ECDA unit cost methodology.[657]

3.4.4.6 TIMP Direct Examination – Expense (MAT HPU)

TIMP direct examinations involve excavating a pipe section, removing the coating, and inspecting all pipe surfaces. PG&E's 2023 forecast for this program (MAT HPU) is $23.965 million.

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654 Cal Advocates Opening Brief, p. 67.

655 Cal Advocates Opening Brief, p. 68.

656 PG&E-16-E, p. 5-51, lines 12-20.

657 PG&E-3-E, WP 5-22, footnote (b). The ECDA unit cost methodology is provided in PG&E-3-E, WP 5-19.

Cal Advocates is the only party that addresses Direct Examination and it proposes more than a 50% reduction in the program forecast to $10.405 million.[658] To support its proposed reduction, Cal Advocates points out that a number of projects identified for work during the rate case period (2023-2026) that have compliance dates before 2023.[659] However, as PG&E explained to Cal Advocates in discovery, the compliance deadlines before 2023 are a result of a change in PHMSA's interpretation of its regulations which occurred on August 27, 2021 after the 2023 GRC was filed. In its data request, Cal Advocates asked why a certain project (DE23_X6526) had a compliance date before 2023. PG&E explained that as a result of the recent PHMSA interpretation, the compliance dates were accelerated and that PG&E was now working to address these accelerated compliance requirements:

> Compliance due dates are primarily determined by the earliest HCA re-assessment due date and are driven by the recent PHMSA interpretation (See Exhibit (PG&E-3), Supplemental Testimony (Aug. 27, 2021), p. 5S-3, line 1 to p. 5S-5, line 16). Some projects like Project "DE23_X6526" are for the assessment of a newly identified threat scheduled past the HCA re-assessment cycle since there was not adequate time to perform the assessment if pulled forward to align with the current cycle (See Exhibit (PG&E-3), Supplemental Testimony (Aug. 27, 2021), p. 5S-7, lines 4-15). As a result of the PHMSA interpretation in 2021, the compliance due date for pipe segments like project "DE23-X6526" were pulled forward into 2020 from a later date, resulting in an overdue compliance date as defined by the recent interpretation. In order to align the assessment of all threats on each pipe segments, projects with similar circumstances have been pulled forward and reprioritized to align the dates as soon as feasible, considering execution timeframe constraints and in some cases prioritized based on risk. PG&E is discussing with CPUC's Safety Enforcement Division (SED) PG&E's plan to comply with the new PHMSA interpretation.[660]

Thus, projects with compliance dates before 2023 do not indicate that PG&E simply missed the compliance date. Instead, these dates reflect the fact that PHMSA changed its interpretation of its regulations which resulted in earlier compliance dates than previously understood. This work

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658 Cal Advocates Opening Brief, p. 69.

659 Cal Advocates Opening Brief, p. 70.

660 CALPA-39, Workpapers, pp. 026-027.

must now be performed. PG&E explained the change in PHMSA interpretation in detail in its testimony.[661]

Cal Advocates also notes that several projects have compliance dates after the rate case period (*i.e.*, after 2026).[662] Again, as PG&E explained in discovery:

> For each 2023 planned Direct Examination project with a compliance due date in 2024, 2026 or 2027, PG&E is first generally forecasting to complete the project at least one year prior to the due date to ensure completion within the compliance due date period, accounting for potential project planning difficulties such as permitting. Second, projects are generally forecast to be bundled in such a way that work crews and contractors are being used efficiently. Third, PG&E's forecast approach is not specifically intended to narrowly define the exact year of completion of each project. It is intended to be an approximate plan that gets the work done within the rate case period.[663]

While almost all of the identified projects have compliance dates before 2027 (*i.e.*, during the rate case period), those that do not are reasonably included to ensure completion by the compliance date (*i.e.*, 2027) and ensure cost efficiency in terms of the utilization of resources.

Cal Advocates also asserts that PG&E fails to explain the pace of the program during the rate case period.[664] However, as Cal Advocates acknowledges in its own Opening Brief, the pace of work is spread out evenly over the four-year rate case period.[665] It is entirely reasonable to spread out work over the four year period rather than trying to do everything at the beginning of the rate case period or to cram it all into the last few years.

Finally, Cal Advocates argues that the Commission ought to adopt the 2020 recorded amount for TIMP direct examinations instead of PG&E's 2023 forecast.[666] However, the scope for 2023 projects is more than double that of the scope completed in 2020, thus supporting a

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661 PG&E-03, p. 5S-3, line 12 to p. 5S-5, line 33 (explaining the change in PHMSA's interpretation and identifying MAT HPU for Direct Examination as an impacted MAT).

662 Cal Advocates Opening Brief, p. 70.

663 CALPA-39, Workpapers, p. 027.

664 Cal Advocates Opening Brief, p. 70.

665 Cal Advocates Opening Brief, p. 69.

666 Cal Advocates Opening Brief, p. 71.

2023 forecast that is more than double.[667] The new PHMSA interpretation accelerates the timeline for PG&E to assess and address new threats through programs such as TIMP direct examination. As we explained in our testimony:

> On June 23, 2021, PHMSA provided its interpretation that "agree[d] with the CPUC's assessment that 49 CFR § 192.939 does not have an exception for newly discovered threats within existing HCAs if they are discovered within an assessment cycle. Therefore, a pipeline operator must assess a newly activated threat on a covered segment within the same assessment cycle as other threats that were previously identified through risk assessment under 49 CFR § 192.917(a) regardless of when the threat becomes active."
>
> This new interpretation provided by PHMSA fundamentally impacts PG&E's transmission integrity management assessment plan. PG&E had previously understood that we had seven years from the date a new threat was identified to perform an HCA re-assessment. Under PHMSA's new interpretation, the HCA re-assessment of a new threat must occur during the 7-year HCA re-assessment cycle. For example, if an HCA re-assessment for existing threats occurred in 2010, the next HCA re-assessment would be required by 2017. If a new threat was identified for the HCA in 2016, rather than having seven years from 2016 to perform an HCA re-assessment (e.g., 2023), under PHMSA's interpretation, an HCA re-assessment of the new threat would be required by 2017 (i.e., the HCA re-assessment deadline for existing threats). PHMSA's new interpretation will result in the acceleration of assessment of newly identified threats and introduction of new assessments… .[668]

It is undisputed that PHMSA's new interpretation impacts the TIMP direct examination program (MAT HPU).[669] Cal Advocates' recommended funding level for the TIMP direct examination program, which based on the number of projects in 2020 before the new PHMSA interpretation, is insufficient to meet the accelerated compliance dates for TIMP direct examinations driven by the new PHMSA interpretation.

3.4.5 Strength Testing And Replacement

Strength tests are conducted on gas transmission pipelines to assess integrity and for purposes of determining or verifying the appropriate maximum allowable operating pressure (MAOP). PG&E's Strength Testing Program includes three sub-programs: (1) strength testing

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667 PG&E-16-E, p. 5-53, lines 4-9.

668 PG&E-03, p. 5S-4, line 19 to p. 5S-5, line 14.

669 PG&E-03, p. 5S-5, line 26.

for non-TIMP purposes as required by federal law and California statutory requirements; (2) strength testing for TIMP purposes as required by federal law; and (3) strength testing associated with liquified and compressed natural gas. PG&E's programs are covered by a number of MATs, some of which are undisputed. TURN is the only party that addressed strength testing. In Table 3-4 below, we identify the disputed strength testing MATs and PG&E's 2023 forecast and TURN's 2023 forecast for each based on information from Table 23 in TURN's Opening Brief:

TABLE 3-4
DISPUTED STRENGTH TESTING MATS AND FORECASTS

Program	MAT	PG&E 2023 Forecast[670]	TURN 2023 Forecast (in $2020)[671]
Non-TIMP Replacement	JT6 (Expense)	$35.443 million	$9.728 million
TIMP Strength Testing	HPF (Expense)	$19.917 million	$18.447 million
TIMP Replacement	HPM (Expense)	$4.153 million	$4.233 million
Non-TIMP Strength Testing	75U (Capital)	$73.325 million	$59.915 million
Non-TIMP Replacement	75R (Capital)	$66.653 million	$33.741 million
TIMP Replacement	75Q (Capital)	$17.899 million	$16.869 million

Please note, however, that to develop Table 3-4 above, PG&E tried to reconcile the proposals in TURN's Table 23 with the proposed MAT reductions in TURN's recommendations on pages xiii to xiv of its Opening Brief. For purposes of Table 3-4 above, PG&E used TURN's proposed amounts from Table 23 in $2020.

TURN raises three issues that it applies broadly to the six TIMP and non-TIMP strength testing programs that it disputes (reflected in Table 3-4 above): (1) the appropriate disallowance factor for pipeline installed after December 31, 1955 that lacks a traceable, verifiable, and complete (TVC) record of a strength test; (2) TURN's regression analysis; and (3) excluding projects from PG&E's forecast based on TURN's argument regarding compliance deadlines. Rather than discussing each of these programs and repeating our arguments on the three issues

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670 PG&E Opening Brief, pp. 160-169.

671 TURN Amended Opening Brief, p. 212, Table 23 (Column TURN Annual Net of TURN Disallowance).

for each program, below we are addressing the three issues raised by TURN generally. These arguments apply to all of the strength testing MATs.

3.4.5.1 Disallowance Factor

PG&E and TURN agree that based on prior Commission decisions, PG&E cannot recover the costs associated with non-TIMP strength tests for pipe installed after December 31, 1955. The question then becomes how to determine the percentage of pipeline that will be strength tested during the rate case period that is subject to this disallowance (*i.e.*, a disallowance factor). This issue applies to a number of TIMP and Non-TIMP strength testing MATs including: (1) Non-TIMP strength testing (MAT 75U); (2) Non-TIMP pipeline replacement capital (MAT 75R) and expense (MAT JT6); and (3) TIMP replacement expense (MAT HPM). We addressed this issue in our Opening Brief.[672]

PG&E and TURN agree that PG&E's original calculation included certain miles that should have been excluded and PG&E has indicated it will adjust its forecast to address this error.[673]

TURN also asserts, however, that PG&E's underlying methodology to calculate the disallowance factor is flawed. TURN calculated its own disallowance factor by performing a "project-by-project analysis."[674] However, as we explained in our Opening Brief, TURN's analysis assumes the strength testing projects for the rate case period are static, which they are not.[675] Projects may be replaced during the rate case period for a variety of reasons, such as changing risks and system constraints.[676] Thus, TURN's analysis is based on strength testing projects that may or may not occur during the rate case period. TURN is effectively proposing to

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672 PG&E Opening Brief, pp. 161-162.

673 TURN Amended Opening Brief, p. 204; PG&E Opening Brief, pp. 161-162.

674 TURN Amended Opening Brief, p. 205.

675 PG&E Opening Brief, p. 162.

676 PG&E-16-E, p. 5-56, n. 174.

disallow costs for projects that may not occur and its analysis fails to consider other projects that may occur. This is why PG&E's approach, which relies on mileage estimates rather than specific projects, is much more reasonable and likely to be representative of the actual work performed.[677]

In its Opening Brief, TURN argues that PG&E used specific projects for its forecast, and thus it is appropriate to use the same projects for the disallowance factor.[678] Using projects to develop a forecast is appropriate, even when those projects will likely change during the rate case period, because the overall scope and unit cost of the work will generally remain the same. However, calculating a disallowance factor is an entirely different matter. As TURN's own evidence makes clear, the length of pipe without a TVC record can vary substantially from pipe to pipe. For example, TURN's testimony notes that for one pipeline 24.3% did not have a TVC record, while in another case it was 100%.[679] Moreover, as TURN's Opening Brief makes clear, a substantial amount of TURN's proposed disallowance is based on a relatively small amount of mileage. For example, TURN identified that 4.2% of the forecasted mileage accounts for 67.4% of its proposal for disallowed project costs.[680] If these projects change, which they well could, the amount of disallowance would decrease significantly. Relying on specific projects, which may or may not occur during the rate case period, creates a false precision for purposes of determining the disallowance factor. While the costs and scope of non-TIMP strength testing work will likely remain the same for forecast purposes, the disallowance percentage on each pipeline section can vary substantially and thus using a project-by-project approach will likely result in a disallowance factor that could be significantly higher than the actual disallowance amount.

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677 PG&E-16-E, p. 5-57, lines 1-3.

678 TURN Amended Opening Brief, p. 213.

679 TURN-04, p. 41, Table 8.

680 TURN Amended Opening Brief, p. 206, Table 19.

Finally, TURN fails to address the fact that the Commission approved PG&E's disallowance methodology in the 2019 GT&S rate case and that no party in that proceeding, including TURN, protested.[681] TURN's proposed disallowance approach for TIMP and non-TIMP strength testing should be rejected.

3.4.5.2 TURN's Regression Analysis

TURN and PG&E both provided regression analyses to determine the appropriate unit costs for various TIMP and Non-TIMP strength testing programs. In our rebuttal testimony, we demonstrated that TURN's analysis was less accurate because the R-square value (which measures accuracy) was lower[682] and that for one program TURN's analysis resulted in a de minimus change in unit costs.[683] TURN argues that it is using more recent data but does not dispute that its regression analysis has a lower R-square value.[684] Simply because an analysis uses more recent data does not necessarily make it more accurate, especially when the R-square score shows that it is not. PG&E's regression analysis, which is more accurate based on R-square values, should be adopted.

3.4.5.3 Excluding Projects Based On Compliance Deadlines

TURN proposes that PG&E defer until the next GRC cycle 65 non-TIMP strength tests (MAT 75U) that do not have a compliance deadline during the rate case period (2023-2026) and operate below 20% specified minimum yield strength (SMYS).[685] TURN does not and cannot dispute that Section 958(c)(1) of the California Public Utilities Code requires all natural gas transmission pipelines to be pressure tested. Moreover, TURN does not and cannot dispute that federal regulations require that certain projects at issue in this proceeding need to have an MAOP

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681 PG&E-16-E, p. 5-56, lines 21-24.

682 PG&E-16-E, p. 5-57, lines 5-15 (R-squared value lower for Non-TIMP strength testing).

683 PG&E-16-E, p. 5-61, lines 21-28 (de minimum change for Non-TIMP replacement capital).

684 TURN Amended Opening Brief, pp. 213-214.

685 TURN Amended Opening Brief, p. 211.

re-confirmation. Both the federal and state requirements were taken into consideration in the development of our non-TIMP strength testing program forecast and cadence.[686]

As we explained in our Opening Brief, PG&E put forward a proposal to comply with California law and federal regulations where applicable using a measured and methodical approach.[687] Because PG&E has a substantial amount of pipeline that needs to be strength tested, and under federal regulations a requirement for 50% MAOP re-confirmation be completed by 2028 and 100% by 2035 for projects subject to federal regulation, we cannot simply wait until the last minute to perform this work. In our rebuttal testimony, we addressed TURN's misunderstanding about the applicable compliance deadlines for this work and why a measured approach was reasonable:

> TURN's assertion that these projects do not have compliance deadlines is not entirely accurate. In addition to the statutory testing requirements in PUC §958, the projects must also ultimately meet the requirements of 49 CFR §192.624, MAOP reconfirmation. TURN noted in its testimony that "Section 192.624 provides until 2035 before 100 percent of the designated pipelines must be assessed." This is not entirely accurate. PG&E explained to TURN in its discovery attachment that "[f]or those that show §192.624 as a regulation that is satisfied, doing the work during this rate case period achieves the pace of 50 percent MAOP reconfirmation to comply with §192.624 (MAOP Re-confirmation) by July 3, 2028." PG&E planned for completion in this rate case cycle of enough §192.624 projects to meet this regulatory deadline imposed by this new section of the federal regulations. TURN supposes, without support, that PG&E could just cram all these projects and more into the next rate case to meet the 2028 compliance deadline. This is another example of TURN's "wait until the last minute" approach to compliance. PG&E would not be able to garner the resources for that much work, the pipeline system could not support so many outages during the 2027-2028 time period, severely constraining the system, and shoving all of this work into the 2027-2028 timeframe in the next rate case would unnecessarily and negatively affect customer rates in the next rate case. As such, the Commission should reject TURN's recommendation to remove projects that TURN does not believe have compliance requirements within the rate case period.[688]

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686 PG&E-16-E, p. 5-58, lines 5-30.

687 PG&E Opening Brief, pp. 162-163.

688 PG&E-16-E, p. 5-58, lines 8-30 (footnotes omitted).

In its Opening Brief, TURN essentially ignores PG&E's testimony regarding compliance deadlines under federal regulations. Instead, TURN argues that its "kick the can down the road" approach will not detrimentally impact PG&E's measured approach because TURN is only suggesting that PG&E defer less than 10% of the forecasted projects.[689] However, TURN offers no evidence, other than rhetoric, that pushing 65 projects into the next rate case can be accommodated. In fact, the only evidence in the record is Mr. Barnes' undisputed testimony that pushing 65 projects into the next rate case could result in resource shortages and ultimately higher costs for customers.[690] There is a substantial amount of strength testing that needs to occur on PG&E's gas transmission system and a measured approach, rather than delays, is the best way for strength testing to be completed in compliance with California law and federal regulations.

Finally, TURN's proposal to defer 65 projects is based largely on Dr. Lesser's discussion of the low RSE values for non-TIMP strength testing.[691] However, TURN is silent on PG&E's discussion in rebuttal testimony explaining that the low RSE scores are to be expected given the many short segments that must be tested and, more importantly, that strength testing is a compliance obligation that must be performed regardless of Dr. Lesser's RSE arguments.[692]

3.4.6 Vintage Pipeline Replacement – Capital (MAT 75E)

PG&E's vintage pipe replacement program targets the threat posed by the presence of construction defects as they interact with outside forces such as land movement. PG&E's capital forecast for this program for 2023 is $10.835 million. TURN is the only party addressing the

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689 TURN Amended Opening Brief, pp. 214-215.

690 PG&E-16-E, p. 5-58, lines 8-30 (footnotes omitted).

691 TURN Amended Opening Brief, pp. 209-211.

692 PG&E-16-E, p. 5-59, lines 5-14.

program and proposes either completely eliminating it, or substantially reducing the 2023 forecast to $3.7 million.[693]

In our Opening Brief, we explained how our Vintage Pipeline Replacement program, which is limited to 0.72 miles of work, is intended to address construction defects in areas where there are land movement risks. TURN does not dispute: (1) the pipeline segments at issue have construction defects; (2) these segments are located in areas with potential land movement risk; (3) PHMSA has urged operators to evaluate this threat; and (4) a gas pipeline explosion in 2011 in Ohio highlights the serious nature of this risk.[694] TURN continues to base its primary recommendation, that the vintage pipeline replacement program be eliminated, on the RSE scores for the program.[695] The problems with TURN's RSE approach are addressed generally in Sections 2.3 and 3.2 of this Reply Brief. With regard to vintage pipeline replacement specifically, TURN's focus on RSEs essentially ignores the testimony of PG&E's witness Bennie Barnes regarding safe operating practices and direction from PHMSA to mitigate pipeline with a potential for failure – such as pipelines with construction defects in areas subject to land movement.[696]

TURN relies on Dr. Lesser's testimony to support its recommendation. But Dr. Lesser has never worked for a gas transmission utility, is not an expert on PHMSA, is not an expert on federal regulations, and has no experience on industry committee such as AGA committees.[697] In short, Dr. Lesser has no way to evaluate or even substantively address the risks described by Mr. Barnes or PHMSA's direction to mitigate these risks.

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693 PG&E Opening Brief, pp. 169-170 and Table 3-29.

694 PG&E Opening Brief, pp. 169-170.

695 TURN Amended Opening Brief, pp. 217-218.

696 PG&E-16-E, p. 6-69, line 15 to p. 5-70, line 3.

697 PG&E-16-E, p. 5-17, lines 9-23.

TURN argues that PG&E will inspect the proposed vintage pipeline replacement projects every 7 years to meet TIMP regulations and that PG&E can address deterioration at that time if needed.[698] TURN is essentially suggesting that even though PG&E knows a pipeline has a construction defect <u>and</u> is located in an area that experiences land movement, we should wait for potentially up to seven years, and maybe more, to see if there is any deterioration. Until the time the next assessment occurs, of course, a pipeline could rupture injuring people and impacting PG&E's gas system. As Mr. Barnes explained in rebuttal testimony:

> The theme underlying TURN's proposal on the Vintage Pipe Replacement program is similar to the theme that runs throughout TURN's testimony – wait until the last minute and hope that there is not an incident which adversely impacts public safety or reliability. PG&E's testimony described past incidents and industry best practices which support the need for the Vintage Pipe Replacement program. PG&E's program is focused on the highest risk situations where "fabrication and construction threats interact with land movement." The Commission should not short change addressing safety and reliability threats simply based on TURN's myopic RSE focus.[699]

TURN's alternative proposal, to limit vintage pipeline replacements to areas with an impacted occupancy count (IOC) of 10 or greater should also be rejected.[700] Although the IOC in these areas are lower, there is a high potential for failure that could impact safety and reliability.[701] As a prudent operator, PG&E has an obligation to mitigate potential failures.

Finally, TURN also raises issues regarding the inclusion of carry-over costs from projects completed in 2021 and 2022 into the unit cost calculation proposed in this GRC.[702] As PG&E explained in its Opening Testimony, the unit cost forecast for vintage pipeline replacement was based on projects completed between 2015-2019 that met certain criteria.[703] PG&E also

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698 TURN Amended Opening Brief, p. 220.

699 PG&E-16-E, p. 5-71, lines 10-19.

700 TURN Amended Opening Brief, p. 220.

701 PG&E-16-E, p. 5-71, lines 23-27.

702 TURN Amended Opening Brief, pp. 220-221.

703 PG&E-03, p. 5-78, line 27 to p. 5-79, line 12.

included in its forecast closeout costs for projects that are forecasted to come on-line in 2021-2022.[704] Because these close out costs will be incurred after the end of the 2019 GT&S rate case period (2019-2022), it is appropriate to include them in the rates for this GRC because otherwise these costs would be stranded.[705] TURN does not dispute that these costs were prudently incurred and offers no evidence to support its rhetorical statement that these costs reflect "PG&E's poor project management leading to cost overruns."[706]

3.4.7 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. 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. PG&E's forecast for 2023 is $4.386 million.[707] TURN is the only party that addresses this program and proposes a forecast of $2.932 million, which is a 35% reduction.[708]

TURN's proposed reduction is based on past underspending.[709] TURN's proposal here appears to be punitive. TURN acknowledges that by using historical spending, PG&E's forecast effectively takes into account past under-spending.[710] However, TURN argues that even though PG&E's prospective forecast for this proceeding resolves the past underspending issue, "it does not account for the $6.8 million that ratepayers overfunded this program during the five years

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704 PG&E-03, WP 5-111.

705 PG&E-16-E, p. 5-72, lines 3-15.

706 TURN Amended Opening Brief, p. 221.

707 PG&E Opening Brief, pp. 174-175 and Table 3-31.

708 TURN Amended Opening Brief, pp. 223-224.

709 TURN Amended Opening Brief, p. 224.

710 TURN Amended Opening Brief, p. 225.

since 2016."[711] TURN does not dispute, however, that PG&E re-prioritized the past funds for other purposes or that in the past PG&E spent more overall for its Gas Operations portfolio than its adopted rates (*i.e.*, adopted rates did not compensate PG&E for its Gas organization costs).[712] Nor does TURN claim that PG&E's forecast in this case, which is based on actual, historical costs, is unreasonable. In short, TURN appears to simply want to punish PG&E for past underspending in this program by reducing the prospective forecast. This is not appropriate.

PG&E also explained that its forecast was higher for this rate case because it has added a new Global Positioning System (GPS) program.[713] TURN does not dispute the merits of this new program or the forecast associated with it. Indeed, TURN candidly admits that it "has not taken issue with specific activities that PG&E proposes to conduct as part of this program in this GRC cycle."[714] TURN returns again to its refrain about past underspending to justify cuts to the new GPS program. TURN's arguments regarding underspending are addressed above.

3.4.8 Shallow And Exposed Pipe (Including Water And Levee Crossings) – Capital (MATs 75M, 75T and 75K)

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.

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711 TURN Amended Opening Brief, p. 225.

712 PG&E-16-E, p. 5-68, lines 6-10.

713 PG&E Opening Brief, p. 175.

714 TURN Amended Opening Brief, p. 225.

PG&E's capital forecast for 2023 is $27.808 million.[715] TURN is the only party that opposes this program and recommends that it be eliminated entirely or, in the alternative that the capital expenditures for each year be reduced by close to 50%.[716]

TURN's primary recommendation that the Shallow and Exposed Pipe program be eliminated is based on its RSE arguments.[717] The fundamental flaws in TURN's RSE arguments are addressed above in Section 2.3 of PG&E's Opening and Reply Briefs. With regard to the Shallow and Exposed Pipe program specifically, TURN ignores the description in PG&E's Rebuttal Testimony of the specific risks being mitigated, instead choosing to narrowly focus on RSE scores:

> TURN ignores common safe operating practices for Transmission pipeline companies where threats are mitigated when they pose a potential danger to safe operation, especially where there are people living within the impact radius of the pipe (i.e., IOC). PG&E's testimony demonstrates that that are multiple high-risk conditions along PG&E's pipeline system that cause PG&E, as a prudent operator, to mitigate shallow, exposed or water/levee crossings. The high likelihood of failure conditions include:
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> - Pipe crossing a Water/Levee that is exposed or less than three feet deep in channel bed in a navigable waterway OR settlement, subsidence or cracking of levee (unstable levee).
> - Shallow pipe in agricultural and/or heavy cultivation OR greater than 90 percent combined stress from potential wheel loading.
> - Exposed: Exposed pipe in agricultural area/navigable waterway or evidence of third-party damage (TPD) potential OR Span Stress greater than or equal to 50 percent SMYS OR in roadway.
>
> These are all conditions that a prudent operator would consider for mitigation and are conditions that a simple look at RSEs does not reveal.[718]

TURN also misunderstands PG&E's testimony that its Shallow and Exposed Pipeline program is site specific. TURN argues that specific site conditions should be factored into RSE

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715 PG&E Opening Brief, pp. 172-173 and Table 3-30.

716 TURN Amended Opening Brief, p. 227, Table 26.

717 TURN Amended Opening Brief, pp. 227-229.

718 PG&E-16-E, p. 5-73, line 23 to p. 5-74, line 12 (footnotes omitted).

scores.[719] However, RSE scores are not sufficiently granular at this point to be prepared on a project-by-project basis. Nor did PG&E claim that its RSE score for the Shallow and Exposed Pipeline program was provided at a project-by-project level. PG&E did explain, however, that in prioritizing projects for the program, it examined specific sites and locations:

> Further, Shallow and Exposed Pipe (Including Water and Levee Crossings), a 2020 RAMP mitigation, is intended to mitigate locations where pipeline have insufficient cover, is vulnerable to exposure from third parties, or has become exposed due to natural forces. This program addresses the following risk drivers (threats): external corrosion, stress corrosion cracking, manufacturing defects, third party damage, and weather related outside force, and construction threats.
>
> . . .
>
> These factors represent site-specific conditions that produce elevated pipeline safety threats and warrant mitigation. These risk factors could lead to an LOC if not addressed through the Shallow and Exposed (Including Water and Levee Crossings) Program.[720]

Specific projects intended to address insufficient pipeline cover or the risk of third-party or natural pipeline exposure addresses obvious safety needs. These needs are evident when the specific projects are considered.

TURN asserts that the Shallow and Exposed Pipeline program is not required by regulations.[721] While this is true, PG&E never asserted that regulatory requirements existed. Instead, we explained that our program is informed by industry and regulatory best practices, including guidance from PHMSA, the California State Lands Commission, and direction from the Central Valley Flood Protection Board.[722] TURN simply choses to ignore these industry and regulatory best practices.

TURN's alternative proposal is to reduce PG&E's Shallow and Exposed Pipeline program forecast by 30% to account for what TURN asserts was "underspending" in the past on

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719 TURN Amended Opening Brief, pp. 231-232.

720 TURN-125, response to TURN_226-Q012(c).

721 TURN Amended Opening Brief, p. 232.

722 PG&E-03, p. 5-126, lines 13-32.

this program.[723] This argument completely ignores the deferred work analysis presented in PG&E's Opening Testimony.[724] As PG&E explained in its testimony, the Shallow Pipe Program (MAT 75M), Water and Levee Crossings Program (MAT 75K), and Exposed Pipe program (MAT 75T) were combined during the 2019 GT&S rate case period because of the similarities between the three programs.[725] Projects were then prioritized so that more water and levee crossings and exposed pipe were addressed. When the adopted amounts for the three programs is combined and compared to actual and forecast expenses, PG&E expects to spend $24 million more for the three combined programs during the 2019 GT&S rate case period (2019-2022) – a forecasted overspend of 30%.[726] TURN simply ignores the undisputed evidence that PG&E will overspend the combined programs during the 2019 GT&S rate case period.

TURN's analysis of underspending is based on an earlier period from 2016-2020.[727] However, even for the earlier period TURN's argument fails. In Rebuttal Testimony, PG&E demonstrated how some funding related to the Shallow and Exposed Pipe program for the period 2016-2020 was reprioritized for other exposed pipe programs.[728] PG&E also demonstrated that when all of these programs are considered, PG&E overspent its authorized amount for these programs.

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723 TURN Amended Opening Brief, pp. 226, 233-235.

724 PG&E-03, p. 5-150, line 20 to p. 5-153, line 5.

725 PG&E-03, p. 5-151, lines 9-27.

726 PG&E-03, p. 5-152, Table 5-57.

727 TURN Amended Opening Brief, p. 226.

728 PG&E-16-E, p. 5-76, line 1 to p. 5-77.

3.5 Asset Family – Facilities[729]

The Compression and Processing (C&P), Measurement and Control (M&C) Stations and Compressed Natural Gas (CNG) asset families (together referred to as "Facilities") include compression and processing facilities as part of the C&P asset family, gas regulation stations as part of the M&C asset family, and CNG stations as part of the Liquefied Natural Gas/ Compressed Natural Gas (LNG/CNG) asset family. In this section of our Reply Brief, we address issues regarding our Facilities program forecasts raised by parties in their Opening Briefs:

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729 Asset Family –Facilities is addressed in Chapter 6 of PG&E's Prepared Testimony, PG&E-03, and further addressed in Chapter 6 of PG&E's Rebuttal Testimony, PG&E-16-E.

TABLE 3-5
ASSET FAMILY FACILITIES DISPUTED PROGRAMS

Section	Disputed Program	Parties
3.5.1	GT Routine C&P Program	TURN
3.5.2	GT M&C Terminal Upgrades	TURN
3.5.3	GT and GD M&C Station OPP Enhancements Program	TURN
3.5.4	HPR Program	TURN
3.5.5	GT C&P Compressor Replacements and Retirements: Los Medanos Compressor Replacement	TURN
3.5.6	GT C&P Compressor Replacements and Retirements: Tionesta Compressor Station Retirement	TURN

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

The Gas Transmission (GT) Routine C&P Expense Program (MAT JTY) includes projects that arise during normal operation of C&P facilities that must be performed to maintain current levels of service and reliability. Typical projects include repair or replacement of failed or malfunctioning equipment and instrumentation, compressor unit overhauls, inspection and testing of asset components, and modifications to address equipment safety or performance issues.[730] PG&E forecast $10 million of expense for this program in 2023.

TURN disagrees with PG&E's forecasting methodology for this program, which is based on a historical 3-year average (2018-2020), escalated to 2023. TURN argues that "the recorded costs declined over the last three years" and thus 2020 costs should be used.[731] This methodology produces a test year forecast of $7.821 million in $2020 or $8.517 million in $2023, which is $1.750 million less than PG&E's request.

PG&E disagrees with TURN's approach.[732] Depending on the type of repair, replacement projects and the facility where work is performed, there is some variation in costs

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730 PG&E-03, p. 6-18, line 12 to p. 6-19, line 21.

731 TURN-05, p. 7.

732 PG&E Opening Brief, pp. 185-186, Section 3.5.1.

expected year over year for the program. In addition, 2020 is not a representative year that should be relied upon for this program due to COVID-19 related delays from pausing non-essential work.[733] PG&E's use of an historical average for forecasting programmatic work accounts for year-over-year fluctuations and provides a predictable trend of the expected future level of work as opposed to relying on a single year as TURN recommends.[734]

In its Opening Brief, TURN provides a table showing the recorded costs for this MAT code as follows: $8.97 million in 2016; $9.35 million in 2017; $10.89 million in 2018; $8.97 million in 2019; and $7.82 million in 2020.[735] Rather than showing a downward trend as TURN claims, these recorded costs prove PG&E's point that 2020 is an abnormally low year. The costs for each year before 2020 are $8.97 million or higher yet TURN wants to use 2020's cost of $7.82 million which is almost 13% lower than $8.97 million, the lowest spend in the previous 4 years. As PG&E explained 2020 was unusually low because of COVID-19 work delays. The recorded costs show both increases and decreases over the 4 years prior to 2020, the base year, and an unusually low 2020 due to forces beyond the control of the utility (COVID-19). The Commission should therefore adopt PG&E's 2018-2020 average approach which is consistent with the Commission guidance cited by TURN:

> For those accounts which have significant fluctuations in recorded expenses from year to year, or which are influenced by weather or other external forces beyond the control of the utility, an average of recorded expenses over a period of time (typical four years) is a reasonable base expense for . . . [the Test Year].[736]

3.5.2 GT M&C Terminal Upgrades – Capital (MAT 765)

The GT M&C Terminal Upgrades Program (MAT 765) includes upgrades and rebuilds to address equipment aging and obsolescence for the three gas terminals at Milpitas, Antioch, and

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733 PG&E-03, p. 2-18, line 13 to p. 2-19, line 18.

734 PG&E-16-E, p. 6-10, lines 11-29.

735 TURN Amended Opening Brief, p. 237.

736 TURN Amended Opening Brief, p. 236, citing D.04-07-022, pp. 15-16.

Brentwood. The GT M&C Terminal Upgrades Program includes two types of work: (1) routine terminal upgrades at all three terminal stations that includes regular upgrades and maintenance to maintain reliability of the GT system, and (2) a phased approach for rebuilding the Brentwood Terminal.[737]

TURN did not make any recommendations related to the Routine Terminal Upgrades work forecast under this program but recommends the removal of all costs for the Brentwood Terminal Rebuild project, which represents a reduction of $14.6 million annually or a total decrease of $58.3 million (un-escalated forecast) for the years 2023-2026.[738]

In its Opening Brief, TURN continues to argue for removal of all Brentwood Rebuild costs but also recommends "[i]f the Commission is disinclined to adopt the recommendation in TURN's testimony, the Commission should at least reduce the forecast by 50%, as a reasonable balance between of the interests of ratepayers and the utility."[739]

TURN opposes "inclusion of the Brentwood Terminal Rebuild in this GRC on the following two grounds: PG&E has not provided used and useful dates for any of the four project phases, and PG&E failed to spend the authorized amounts in prior years."[740] PG&E responds to these arguments below.

As a threshold matter, it is important for the Commission to understand the significant operational and safety risks if the Brentwood Terminal Rebuild does not receive funding. As explained in PG&E's Opening Brief,[741] the Brentwood Terminal is one of the most critical pressure control facilities along PG&E's gas transmission lines. The complexity of the facility,

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737 PG&E-03, p. 6-46, line 28 to p. 6-48, line 11.

738 TURN-05, p. 9. PG&E is reflecting TURN's adjustment to eliminate funding for this project completely, including escalation as reflected in PG&E-03-ES, WP 6-46, line 3 ($59.4 million in 2023-2026). This is reflected in PG&E-16-E, p. 6-6, Table 6-4.

739 TURN Amended Opening Brief, p. 242.

740 TURN Amended Opening Brief, p. 239.

741 PG&E Opening Brief, pp. 189-190.

as well as equipment obsolescence and age, play a crucial role in the reliability of this terminal. Based on these factors, the Brentwood Terminal has been identified for rebuild to mitigate current and future risks. The rebuild project as planned will significantly improve the reliability of this terminal.

TURN's claims that "PG&E does not provide operative dates for each phase."[742] However, as explained in PG&E's Opening Brief, 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.[743] Based on this, PG&E's forecast 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; this reflects the expectation that the phases will occur in sequence and be complete by the end of the 2023 GRC period.[744]

TURN's argument is that PG&E has underspent on this project in the 2019-2022 period, and will not complete its 2019 GT&S work scope, is without merit[745] As PG&E discusses in its Opening Brief:[746] (1) for MAT 765, the forecast cost is $30.35 million compared to $26.88 million adopted[747] for the same period, resulting in an <u>overspend</u> of $3.46 million; (2) although the 2019 and 2020 recorded costs for the terminal upgrade (about $1.7 million) were lower than the annual spending forecast by PG&E for those two years in the 2019 GT&S case, due in part to COVID-19 related delays and work requirements, the 2019-2022 recorded and forecast cost for the Brentwood Terminal Rebuild project portion of MAT 765 is

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742 TURN Amended Opening Brief, p. 239.

743 PG&E Opening Brief, pp. 187-188, Section 3.5.2.1.

744 PG&E Opening Brief, p. 188.

745 TURN Amended Opening Brief, pp. 239-242.

746 PG&E Opening Brief, p. 189, Section 3.5.2.2.

747 PG&E-03, WP 6-105, line 7.

$12.04 million;[748] and (3) PG&E ramped up the work on the Brentwood Terminal Rebuild project in 2021 to forecast completion of the 2019 GT&S forecast scope of work by 2022.[749]

3.5.3 GT And GD M&C Station OPP Enhancements Program – Expense And Capital (MATs FHQ, JTX, 50N And 76G)

The Gas Transmission (GT) and Gas Distribution (GD) M&C Station Overpressure Protection (OPP) Enhancements program prevents large overpressure (OP) events due to equipment-related failure at regulator stations. PG&E's M&C Station OPP program initiatives address "common mode failure"[750] of pilot-operated regulators at both GT and GD station assets. 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 -slamshuts- (valves that that automatically shut off gas if pressure rises above a certain threshold) or, if required, alternate technologies and relief valves. For GD, PG&E's 2023 forecasts are $1.8 million for expense, and $19.6 million for capital. For GT, PG&E's 2023 forecasts are $1.1 million for expense, and $41.4 million for capital.[751]

TURN is the only party that addresses this program and proposes to completely eliminate all expense and capital funding for both GD and GT.[752] PG&E responds to TURN's arguments in support of its position below.

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748 PG&E-16-E, p. 6-15, Table 6-8.

749 PG&E-16-E, p. 6-15, lines 8-21.

750 Both the regulator and monitor (the primary OPP device) installed in many of these stations can fail in the "open" position—known as the "common mode failure"—when affected by contaminants in the system (sulfur, liquids, and other debris). PG&E Opening Brief p. 190-191.

751 PG&E Opening Brief, p. 190-192, Section 3.5.3

752 TURN Amended Opening Brief, pp. 250-259, Section 3.5.4.

3.5.3.1 TURN Failed To Provide Testimony Addressing PG&E's Operational Justifications For The Over Pressure Protection Program

PG&E's GT and GD M&C Station OPP Enhancements Program is designed to prevent overpressure or "OP" events due to equipment failure that can result in loss of containment with ignition with significant impacts related to injuries and fatalities, loss of service, and/or equipment damage. The program is driven by the following:[753] (1) causal evaluations of large OP events experienced between 2011 to present to determine the cause and to define actions to prevent recurrence; (2) industry events such as the 2018 incident in Merrimack Valley, Massachusetts that caused a series of structure fires and explosions after high-pressure natural gas was released into a low-pressure natural gas distribution system;[754] (3) the AGA identified that installing secondary OPP devices such as slam-shuts is recognized as a leading practice to prevent OP events; [755] and (4) Rulemaking initiatives by PHMSA that would require operators to mitigate common failure mode failure conditions and have appropriate secondary OPP devices (e.g., slam-shuts, relief valves, etc.) to prevent and mitigate OP events.

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753 PG&E Opening Brief, p. 193-195, Section 3.5.3.1.

754 NTSB, Overpressurization of Natural Gas Distribution System, Explosions and Fires, Merrimak Valley, Massachusetts (Sept. 13, 2018),.Report No. PAR-19-02, <https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR1902.pdf> (as of Dec. 4, 2022).

755 State law encourages operators to exceed minimum requirements and apply best practices. California Public Utilities Code Sections 961(b), (c) and (d): "Each gas corporation shall develop a plan for the safe and reliable operation of its commission-regulated gas pipeline facility" that "shall be consistent with best practices in the gas industry" and "[m]eet or exceed the minimum standards for safe design, construction, installation, operation, and maintenance of gas transmission and distribution facilities prescribed by regulations."

TURN provided no testimony addressing these drivers. Instead, relying on a witness with no experience related to gas operations,[756] TURN chose to use a single factor – the RSE score – to summarily recommend cancellation of these programs. While TURN faults PG&E for not explaining adequately, in TURN's view, how RSE scores were considered in its forecast,[757] by relying solely on the RSE score TURN ignores the S-MAP Settlement Agreement[758] that states RSEs are not meant to be the sole determining factor regarding whether risk control or risk mitigation programs should be selected for funding. In its Opening Brief, TURN tries to remedy its failure to address in testimony PG&E's justifications for the Over Pressure Protection programs. These arguments are addressed below.

First, TURN calls PG&E's program drivers "qualitative arguments" contrary to the Commission's multi-year efforts to inform the record with quantitative RSE analysis that allows prioritization of risk reduction proposals.[759] The mere existence of RSE scores, however, does not mean drivers such as causal evaluations of OP events, recent industry OP events, leading or best practices recommended by the AGA, and trends in regulation being considered by PHMSA carry no weight. TURN fails to address these factors except in its Opening Brief. As required by the S-MAP Settlement, RSEs are not the sole factor to be considered in evaluating programs.

Second, TURN down-plays the potential impact of PHMSA's rulemaking initiatives pursuant to the federal PIPES Act of 2020, calling them "speculation."[760] However, proposed

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756 PG&E Opening Brief, p. 195 "As TURN acknowledged in discovery, Dr. Lesser was not testifying as an expert in gas transmission or distribution operations; has not worked as an employee of a natural gas transmission or distribution utility; is not an expert on federal integrity management regulations; and had no experience working on any committee of the AGA. . . . By contrast, as Director of Facility Integrity Management and Technical Services, PG&E witness Terry White was responsible for the Facility Integrity Management Program which is focused on the safety and reliability of gas transmission and distribution station facilities."

757 TURN Amended Opening Brief, p. 255.

758 D.18-12-014, Attachment A, Appendix A, p. A-14, No. 26.

759 TURN Amended Opening Brief, p. 257.

760 TURN Amended Opening Brief, p. 257.

rules pursuant to the PIPES Act would require operators to have appropriate secondary OPP devices to prevent and mitigate OP events and are likely to become a requirement in the future.[761] Specifically, the Act amended existing federal law as follows:

> Not later than 1 year after the date of enactment of this subsection, the Secretary shall promulgate regulations to require that each operator of a distribution system assesses and upgrades, as appropriate, each district regulator station of the operator to ensure that . . . the regulator station has secondary or backup pressure-relieving or overpressure-protection safety technology, such as a relief valve or automatic shutoff valve, or other pressure-limiting devices appropriate for the configuration and siting of the station and, in the case of a regulator station that employs the primary and monitor regulator design, the operator shall eliminate the common mode of failure or provide backup protection capable of either shutting the flow of gas, relieving gas to the atmosphere to fully protect the distribution system from over pressurization events, or there must be technology in place to eliminate a common mode of failure.[762]

Promulgation of regulations requiring installation of secondary OPP on district regulator stations is therefore a requirement under the PIPES Act, and not "speculation" as TURN claims. Currently, regulations implementing this section are scheduled to be released in the Federal Register on May 10, 2023.[763]

Third, TURN argues that the OPP programs are classified by PG&E as Type 4 "risk reduction" programs, meaning PG&E views them as discretionary.[764] While under PG&E's Risk Based Portfolio Prioritization Framework this program is categorized as Work Type 4, which includes "discretionary" risk reduction initiatives, Subject Matter Expert input and judgment regarding the operational need for programs are a critical part of the prioritization

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761 PG&E-16-E, p. 6-22, lines 1-3.

762 Consolidated Appropriations Act, 2021, Division R, Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act), Title 11, Section 206 "Pipeline Safety Practices." The new code section addressing District Regulator Stations is codified at 49 USC Section 60102, Section (t)(3), <https://rules.house.gov/sites/democrats.rules.house.gov/files/BILLS-116HR133SA-RCP-116-68.pdf> (as of Dec. 5, 2022).

763 See line item addressing Section 206 of the PIPES Act, <https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-11/11.4.22%20PIPES%20Act%20Website%20Chart.pdf> (as of Dec. 5, 2022).

764 TURN Amended Opening Brief, p. 257.

process.[765] In other words, Type 4 work can nevertheless be required based on the judgment of the managers and experts responsible for the safety of the assets. As PG&E's witness Terry White, Director of Facility Integrity Management and Technical Services responsible for the safety and reliability of regulator stations testified:

> OP events caused by threats such as equipment failure, incorrect operation, third-party incidents and external events (e.g., wildfire) at regulator stations have the potential to create catastrophic events at locations downstream of the station if not mitigated. In my judgement, addressing these threats proactively through this secondary OPP enhancements program is required as part of prudent gas system risk management and is a best practice.[766]

Finally, TURN argues that the remaining OPP devices to be installed are low risk since PG&E targeted the riskiest assets first.[767] PG&E addresses this argument at length in its Opening Brief.[768] Contrary to TURN's argument, <u>all</u> pilot-operated regulator stations are susceptible to common mode failure and carry the risk of large OP events.[769] PG&E's proposed program is therefore needed to address a significant portion of remaining pilot-operated facilities that carry the risk of large OP events during the 2023 GRC period.

3.5.3.2 Risk Scores Do Not Justify Cancelling The Over-Pressure Protection Program

TURN recommends that the Commission not authorize a continuation of funding for the OPP programs because according to TURN the programs have low RSEs and significant costs.[770] PG&E addressed TURN's use of RSE scores and benefit cost ratios to defund gas

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765 PG&E-16-E, p. 6-21, fn. 29 and PG&E-03, p. 2-22, lines 16-18.

766 PG&E-16-E, p. 6-21, lines 18-24.

767 TURN Amended Opening Brief, p. 258. See also p. 253 "given that PG&E began this program in 2017 and will have addressed 50% of the targeted assets by the end of 2022, PG&E should have been prioritizing the highest risk locations first, leaving relatively lower risk locations for this rate case period."

768 PG&E Opening Brief, p. 195-196, Section 3.5.3.2.

769 PG&E-16-E, p. 6-22, lines 25-26.

770 TURN Amended Opening Brief, pp. 252-259, Section 3.5.4.2.

saftey programs in its Opening Brief.[771] As discussed there, TURN's RSE score and benefit-cost ratio analysis is seriously flawed, inconsistent with Commission precedent, and TURN uses RSE scores for a purpose that was never intended. Furthermore, the S-MAP Settlement Agreement[772] states, and TURN itself recognizes,[773] that RSEs are not meant to be the sole determining factor regarding whether risk control or risk mitigation programs should be selected for funding.

TURN also claims "PG&E chose to ignore the low RSE results for this program."[774] The Gas Operation programs proposed for funding in this GRC, however, are based on a series of prioritization investment decision meetings where proposed programs were evaluated based on contribution to risk reduction, code compliance and reasonableness.[775] PG&E considered RSE scores as part of its prioritization process. Specifically, within Work Type 4, RSE's were referenced to inform potential opportunities.[776] Furthermore, PG&E testified that the RSE scores were available to be evaluated and reviewed in the calibration process as part of portfolio review.[777] Thus, TURN's claim that RSE scores were ignored is not correct.

TURN further claims that PG&E agrees with TURN that RSE analysis provides the best assessment of the reduction in frequency of large OP events and risk reduction that would result from PG&E's proposal.[778] This claim is based on a response to a discovery question that asks "What is PG&E's best assessment of the risk reduction that would result from PG&E's proposed

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771 PG&E Opening Brief, pp. 43-44, Section 2.3.2.

772 D.18-12-014, Attachment A, Appendix A, p. A-14, No. 26.

773 TURN-02, p. 46, lines 9-10.

774 TURN Amended Opening Brief, p. 255.

775 PG&E-03, p. 2-20, line 22 to p. 2-22, line 24.

776 PG&E-03, p. 2-22, lines 5-6.

777 Tr. Vol. 5, 874:15-18, PG&E/Kerans.

778 TURN Amended Opening Brief, p. 256.

programs?" In response, PG&E provided the risk model calculation results for the risk reduction (non-discounted) for the work done in the years 2023 to 2026 for the GT and GD Station OPP Enhancement programs.[779] PG&E did not agree that the RSE scores are "the best assessment of risk reduction." As PG&E explained further in its response:

> [T]he LRGOP Risk Model considers the risk of OP events; however, the model is still evolving and as described in PG&E's Enterprise and Operational Risk Management (EORM) rebuttal testimony (Exhibit (PG&E-15), p. 1-10, lines 24-27), "the RSEs are inherently uncertain and are highly sensitive to alternative MAVF specifications and other uncertain inputs such as mitigation effectiveness assumptions and future changes in the risk landscape". PG&E's secondary OPP program is a prudent operating practice to mitigate large OP events when they pose a potential danger to safe operation of a station and may have a potential public safety impact. The inception and continuation of the Station OPP program is not based on RSEs but based on quantitative and qualitative analysis of large OP events experienced, causal evaluations, corrective actions, and industry best practices.[780]

3.5.4 HPR Program – Capital (MWC 2K)

The function of regulator stations is to regulate and control pressure and provide protection of downstream assets from system pressure excursions. PG&E refers to spring-operated regulators as high pressure regulators or "HPRs." PG&E developed the HPR Program[781] to address gas leaks and facility conditions associated with HPR facilities. Where possible and cost effective, units will be removed and eliminated. Alternatively, HPR units may be rebuilt or updated to an acceptable design configuration or converted to a district regulator station where appropriate. An additional option is to convert the HPR customer to a non-natural gas alternative source and then remove the HPR and associated service facilities.[782]

PG&E is planning to replace 100 HPR units each year for the 2023-2026 period to complete the program by 2026. PG&E's 2023 capital cost forecast is $17.8 million.[783]

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779 TURN-128, PG&E Response to TURN_229-Q001(d).

780 TURN-128, PG&E Response to TURN_229-Q001(e).

781 The HPR program is described and addressed in PG&E Opening Brief, p. 197.

782 PG&E-03, p. 6-58, line 9 to p. 6-60, line 3.

783 PG&E-03, p. 6-59, lines 4-9.

TURN proposes the complete elimination of PG&E's forecast for this program.[784] PG&E responds to TURN's arguments in support of its position below.

3.5.4.1 TURN Failed To Provide Testimony Addressing PG&E's Operational Justifications For The HPR Program

In its Opening Brief, PG&E explained the operational drivers for this program.[785] The HPR mitigation program rebuilds or replaces HPRs to address equipment deterioration, obsolescence, and legacy designs.[786] This program was approved for implementation and adopted by the Commission in the 2011, 2014, 2017 and 2020 GRCs. Addressing equipment obsolescence and equipment failure is required as part of prudent gas system risk management and asset management strategy so that these facilities can be returned to normal maintenance and inspection activities.[787]

TURN did not take issue with PG&E's testimony that describes these operational drivers for the HPR program. Only TURN witness Lesser addressed this program and recommended no funding based on the RSE scores for this program.[788] As discussed in PG&E's Opening Brief, witness Lesser lacks any qualifications with regard to operational gas issues.[789] In its Opening Brief, TURN makes several arguments to bolster its position that this safety program should be defunded completely. PG&E responds below.

First, TURN calls PG&E's program drivers "qualitative arguments" contrary to the Commission's multi-year efforts to inform the record with quantitative RSE analysis that allows prioritization of risk reduction proposals.[790] The mere existence of RSE scores, however, does

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784 TURN-02, p. 138, lines 1-4.

785 PG&E Opening Brief, p. 198.

786 PG&E-03, p. 6-58, line 9 to p. 6-59, line 10.

787 PG&E-16-E, p. 6-25, line 26 to p. 6-26, line 19.

788 TURN-02, p. 118, line 15 to p. 119, line 3.

789 PG&E Opening Brief, p. 195.

790 TURN Amended Opening Brief, p. 264.

not mean drivers such as gas leaks on the transmission system associated with HPR facilities,[791] and equipment deterioration, obsolescence, and legacy designs carry no weight. TURN fails to address these factors except in its briefs. As required by the SMAP Settlement Agreement, RSE's are not the sole factor to be considered in evaluating programs.[792]

Second, TURN claims that "PG&E's proposal for the remaining HPR assets to be addressed in 2023-2026 will provide minimal risk reduction benefits compared to the proposed expenditure [and] that the higher risk stations have been addressed."[793] As explained in PG&E's Opening Brief, the HPR mitigation program was established, however, to address all HPRs that have age and obsolescence risk, not just a subset of high-risk assets as TURN recommends. While the higher risk stations have been addressed, there are still more than 400 HPRs that are to be addressed so that they can be returned to a similar maintenance, inspection, and replacement schedule as the other types of regulator stations.[794]

3.5.4.2 Risk Scores Do Not Justify Cancelling the HPR Program

TURN recommends that the Commission not authorize a continuation of funding for the HPR program because according to TURN the program has a low RSE score and significant costs.[795] PG&E addressed TURN's use of RSE scores and benefit cost ratios to defund gas saftey programs in its Opening Brief.[796] As discussed there, TURN's RSE score and benefit-cost ratio analysis is seriously flawed, inconsistent with Commission precedent, and TURN uses RSE scores for a purpose that was never intended. Furthermore, the S-MAP Settlement

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791 PG&E Opening Brief, p. 198.

792 D.18-12-014, Attachment A, Appendix A, p. A-14, No. 26.

793 TURN Amended Opening Brief, p. 265.

794 PG&E-16-E, p. 6-26, line 25 to p. 6-27, line 15.

795 TURN Amended Opening Brief, p. 262.

796 PG&E Opening Brief, pp. 43-44, Section 2.3.2.

Agreement[797] states, and TURN itself recognizes,[798] that RSEs are not meant to be the sole determining factor regarding whether risk control or risk mitigation programs should be selected for funding.

TURN also claims “PG&E chose to ignore the low RSE results for this program.”[799] The Gas Operation programs proposed for funding in this GRC, however, are based on a series of prioritization investment decision meetings where proposed programs were evaluated based on contribution to risk reduction, code compliance and reasonableness.[800] PG&E considered RSE scores as part of its prioritization process. Specifically, within Work Type 4, RSEs were referenced to inform potential opportunities.[801] Furthermore, PG&E testified that the RSE scores were available as part of portfolio review.[802] Thus TURN’s claim that RSE scores were ignored is not correct.

TURN further claims that PG&E agrees with TURN that RSE analysis provides the best assessment of the reduction in frequency risk events and risk reduction that would result from PG&E’s proposal.[803] This claim is based on a response to a discovery question that asks “What is PG&E’s best assessment of the risk reduction that would result from PG&E’s proposed programs?” In response, PG&E provided the risk model calculation results for PG&E’s risk model calculation results for the frequency reduction for the years 2023 to 2026 for each of the

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797 D.18-12-014, Attachment A, Appendix A, p. A-14, No. 26.

798 TURN-02, p. 46, lines 9-10.

799 TURN Amended Opening Brief, p. 263.

800 PG&E-03, p. 2-20, line 22 to p. 2-22, line 24.

801 PG&E-03, p. 2-22, lines 5-6.

802 Tr. Vol. 5, 874:15-18, PG&E/Kerans.

803 TURN Amended Opening Brief, p. 264.

two risks for this program.[804] PG&E did not agree that the RSE scores are "the best assessment of risk reduction." As PG&E explained further in its response:

> [I]n the judgment of PG&E's subject matter expert, who has many years of experience operating and maintaining natural gas transmission and distribution systems, this program is required as part of prudent gas system risk management. With respect to cost effectiveness calculations, PG&E's Enterprise and Operational Risk Management rebuttal testimony, Exhibit (PG&E-15), Chapter 1, addresses the narrow use of RSE scores and Benefit Cost Calculations by TURN's witness who has no gas system operational or safety experience to reach flawed conclusions about PG&E's programs.[805]

3.5.5 GT C&P Compressor Replacements And Retirements: Los Medanos Compressor Replacement (MAT 76X)

The GT C&P Compressor Replacements and Retirements Program focuses 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. 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.[806]

PG&E's 2023 GRC forecast for MAT 76X reflects two projects: (1) Los Medanos K-1 Compressor Replacement, and (2) Tionesta Compressor Station Retirement. This Section 3.5.5 addresses the Los Medanos Compressor replacement. The Tionesta Compressor Retirement is addressed in Section 3.5.6 below. PG&E forecast $19.1 million in 2023 to cover both the Los Medanos replacement, and the Tionesta retirement.

PG&E's forecast $49.9 million over the rate case cycle for replacement of the Los Medanos storage field compressor station.[807] TURN argues first that "this replacement will not

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804 TURN-128, PG&E Response to TURN_229-Q004(c).

805 TURN-128, PG&E Response to TURN_229-Q004(d).

806 PG&E-03, p. 6-30, line 18 to p. 6-34, line 16.

807 PG&E-3-ES, WP 6-38, Line 10.

be necessary at all if the Los Medanos field is not retained." The need to retain the Los Medanos storage filed is addressed in PG&E's Opening Brief[808] and in Section 3.6 of this Reply Brief. Even if the Los Medanos storage field is retained, TURN argues in the alternative that all requested funding for the replacement of the Los Medanos compressor station should be denied.[809] PG&E addresses TURN's arguments for denial of funding below.

3.5.5.1 The Los Medanos Compressor Project Is Not Deferred Work

The Los Medanos Compressor project is not deferred work as explained in PG&E's Opening Brief.[810] First, one of the criteria for deferred work under the 2020 GRC Settlement Agreement is "PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work." This criterion is not met because the Los Medanos replacement was not requested or funded in the 2019 GT&S case, there was simply no authorized or funded work to defer.[811] Second, TURN incorrectly argues that deferred work exists for Los Medanos compressor because the Commission originally authorized funding in the 2015 GT&S rate case, but the replacement was not performed. In the 2019 GT&S rate case, no party, including TURN, recommended a disallowance or ratemaking adjustment for PG&E's decision not to replace the Los Medanos K-I compressor, and the Commission did not identify MAT 76X as a MAT code with deferred work in the 2019 GT&S Decision (D.19-09-025).[812] The issue of deferred work related to not performing the Los Medanos compressor replacement

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808 PG&E Opening Brief, pp. 232-233, Section 3.6.4.

809 TURN Amended Opening Brief, p. 247.

810 PG&E Opening Brief, pp. 202-205, Section 3.5.5.1.

811 PG&E Opening Brief, pp. 202-203.

812 PG&E-16-E, p. 6-35, lines 1-4. In the 2019 GT&S decision, the Commission determined deferred work existed for the following programs: External Corrosion Direct Assessment (ECDA, MAT HPC and HPN) D.19-09-025, p. 145, p. 300, FOF 68 and p. 312, COL 58; Internal Corrosion Direct Assessment (ICDA, MAT HPJ and HPO) D.19-09-025, p.145 and p. 312, COL 59; and Capacity to Support Normal Operating Pressure Reductions (MWC 73), D.19-09-025, p. 216.

as authorized in the 2015 GT&S case was therefore resolved in the 2019 GT&S case. To argue, as TURN does now, that the 2015 authorization for this project is the basis for a deferred work finding in the 2023 GRC violates the principle of *res judicata* and is an improper attempt to undo the 2019 GT&S rate case decision.[813] Finally, as discussed further in Section 3.5.5.2 below, PG&E showed in the 2019 GT&S case that the funding approved in the 2015 GT&S case for the Los Medanos replacement was reallocated to other safety and reliability projects.

In its Opening Brief, TURN continues to argue that Los Medanos is deferred work because it was funded in the 2015 GT&S case, and not performed.[814] TURN argues that while Los Medanos compressor was not requested in the 2019 GT&S case, it was requested (and funded) in the GT&S case prior to that one. TURN argues that "PG&E cannot be allowed to escape the requirements of the deferred work principles by delaying its duplicate request by two rate case cycles rather than one."[815]

The Commission authorized funding for the replacement of the Los Medanos compressor in the 2015 GT&S case. The project was cancelled given the plan at the time to retire the Los Medanos storage field. PG&E reprioritized the funding to other safety and reliability projects. No party objected to these actions in the 2019 GT&S case and the Commission found no deferred work associated with MAT 76X based on the 2015 GT&S funding. To now claim, two rate cases later, that notwithstanding the foregoing, PG&E remains liable for a disallowance for not spending the funding on the Los Medanos project violates legal principles of *res judicata*; would destabilize the GRC and create uncertainty; violates the rate case principle of reasonable (and expected) reprioritization of funding adopted by the Commission; and is contrary to the accepted way that deferred work has been analyzed under both the 2017 and 2020 GRC Settlements. These points are elaborated below.

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813 PG&E Opening Brief, p. 204.

814 TURN Amended Opening Brief, p. 248.

815 TURN Amended Opening Brief, p. 249.

First, the issue of deferred work for projects funded in the 2015 rate case was resolved in the 2019 GT&S case and should not be relitigated two rate cases later. This approach violates principles of *res judicata* and seriously undermines the stability and finality of determinations made by the Commission in its rate cases. The Commission has recognized that "[r]es judicata principles are among the most fundamental in our legal system, protecting parties from endless relitigation of the same issues."[816] While Public Utilities Code Section 1708 gives the Commission the discretion to "rescind, or amend any order or decision made by it" this is an "extraordinary remedy."[817] In the current situation, the salient facts have not changed since the 2019 GT&S case. The Los Medanos compressor replacement authorized in the 2015 GT&S case was not performed for valid reasons and the unused funding was reprioritized to other work as shown in the 2019 GT&S case. No party disputed these facts. A result the Commission did not identify the project as deferred work. Thus, no basis exists to relitigate this issue or change the Commission's conclusion reached in the 2019 GT&S case. Defining deferred work as relating to work authorized, but not performed, two or more rate case cycles ago is a recipe for uncertainty. If the Commission adopts this approach, there will never be closure on any given rate case. Revenues adopted will always be subject to claw-back in future case regardless of whether the Commission determined that there was no deferred work in the earlier case, and regardless of whether the unused funding was subsequently reallocated to other activities.

Second, this approach also undermines a bedrock principle of rate case funding: That the utility is not only expected, but obligated to adjust and reprioritize authorized spending if actual circumstances differ from assumptions made when work was forecast (emphasis added):

> It is generally recognized that when a utility files a GRC, expenditure estimates are based on plans and preliminary budgets developed at least two years in advance of when they will actually be incurred. When the utility finalizes its budget just prior to the year when costs will be incurred or adjusts the budget during the year, new programs or projects may come up, others may be cancelled,

816 Decision No. 92058, 4 CPUC2d 139, 1980 Cal. PUC LEXIS 785, *23-*24.

817 *Id*.

> and there may be reprioritization. **This process is expected and is necessary for the utility to manage its operations in a safe and reliable manner**.[818]

In other words, reallocating funding from authorized work that is no longer needed, like PG&E did for Los Medanos in the 2015 GT&S rate case period, is not deferred work, and is expected as part of reprioritization. If such reasonable reprioritization is subject to second guessing and penalties in later rate cases, a disincentive is created to performing needed reprioritization contrary to the Commission's determination that such action is "expected and necessary."

Third, for all the rate case cycles under both the 2017 GRC and 2020 GRC Deferred Work Settlement Agreement criteria, PG&E has applied the deferred work analysis consistently to evaluate work expected to be performed in the current rate case cycle against "authorized and funded work, as measured by authorized (explicit or imputed) units of work" <u>for that same rate case cycle</u>. In the 2019 GT&S case, 2015 GT&S funded work for the 2015-2018 period was compared against expected units to be completed during those years.[819] Similarly, in its deferred work analysis presented in the 2020 GRC, PG&E compared the work units authorized in the 2017 GRC for the 2017-2019 rate period against the work PG&E expected to complete over the 2017-2019 period.[820] Finally, in the current GRC PG&E compared work units authorized in the 2020 GRC for the 2020-2022 rate period against the work PG&E expected to

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818 D.11-05-018, p. 27 (emphasis added).

819 A.17-11-09, PG&E-1, p. 4-19, lines 10-11 (for safety or reliability work funded in the 2015 GT&S case, PG&E "determined whether it expects to perform all the funded units of work from 2015 -2018.")

820 A.18-12-009, HE-10: Exhibit PG&E-3, p. 2-34, lines 1-3 (PG&E identified "if the work is presented as unitized or non-unitized in the 2020 GRC and if PG&E expects to perform all of the imputed units between 2017 and 2019." See also HE-11: Exhibit PG&E-3, WP 2-98 to WP 2-105, Table 2-10 and HE-26, Exhibit PG&E-14, pp. 14-99 to 14-105, Columns M and N.

complete over the 2020-2022 period.[821] For GT&S work in the current GRC, PG&E compared work units authorized in the 2019 GT&S for the 2019-2022 rate period against the work PG&E expected to complete over the 2019-2022 period.[822]

This approach of comparing work authorized for a rate case period to work completed for that same rate case period has been the accepted practice and approach in performing deferred work analysis and PG&E is not aware that TURN or any other intervenor has argued in any case that this is not the correct way to perform deferred work analysis as required by the Deferred Work Settlement. The 2020 GRC Settlement states "PG&E will continue to make a 'deferred work showing' consistent with the format of the showing in PG&E's 2020 GRC testimony."[823] PG&E has done exactly that. The Commission should reject the notion that this practice should be discarded, and deferred work should be evaluated against work approved in any prior rate case, even though no work was authorized for the current period under consideration.

Fourth, if deferred work analysis is required to go back to review of funding in earlier GRCs than the prior rate case, PG&E will be faced with the cumbersome if not impossible task of tracking all prior funding, and reprioritization decisions, in performing the deferred work analysis even if that analysis goes back many years (e.g., seven years in the case of the 2015 GT&S period). This is likely to be unmanageable and result in significant disputes regarding data and actions going back indefinitely.

Fifth, TURN's approach is inconsistent with the Commission's RSAR process, where utilities were required to submit an annual report that:

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821 PG&E-03, p. 2-37, line 28 to p. 2-38, line 2 ("to analyze whether 'PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work' (Check 2) GO first evaluated whether units were imputed for the work based on the 2020 GRC decision or the 2019 GT&S decision. GO then compared for GRC work 2020 recorded units, and for GT&S work 2019 and 2020 recorded units, and 2020 and 2022 forecasts to the units imputed for the period 2020-2022 (2019 – 2022 for GT&S)." See also, Workpapers, PG&E-03, WP 2-13, Table 2-13 (GD), and WP 2-16, Table 2-5 (GT), "Unit Comparison" columns.

822 *Id.*

823 2020 GRC Settlement Agreement adopted in the final GRC decision, D.20-12-005, Section 5.2.

> would compare the utility's GRC projected spending for approved risk mitigation projects to the actual spending on those projects, and to explain any discrepancies between the two. [¶] . . . [¶] [The report] shall be filed and served by the utility **in its applicable GRC proceeding in which funding for the risk mitigation activities and spending was authorized** . . . [and] shall report on the activities and spending the utility undertook during the GRC test year, and during each attrition year.[824] (emphasis added)

Thus, the RSAR requires PG&E to identify and explain variances between imputed units authorized for the current time period (not some prior time period), compared to actual units and funding for the same time period. This approach is consistent with the way in which deferred work is evaluated in the GRC.

Finally, TURN claims that PG&E recognized that deferred work may be an issue with the Los Medanos replacement because an internal management document states "Deferred work trigger potential for LM compressor Replacement."[825] That PG&E recognized internally, however, that a deferred work argument <u>might be</u> raised is not dispositive of whether in fact deferred work actually exists in the 2023 GRC for the Los Medanos project. Deferred work should be addressed on the merits and for the reasons explained above and in PG&E's Opening Brief, the Commission should find that no deferred work exists for the Los Medanos project.

3.5.5.2 2015 Funding for Los Medanos Was Reallocated As Shown In The 2019 GT&S case

In its Rebuttal Testimony and its Opening Brief, PG&E demonstrated how it reprioritized the Los Medanos funding from the 2015 GT&S rate case to other high-priority C&P programs.[826] Specifically, PG&E provided testimony in the 2019 GT&S rate case showing 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. Thus, PG&E reallocated $47.7 million of the Los Medanos funding to

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824 D.14-12-025, p. 44 and p. 46.

825 TURN Amended Opening Brief, p. 248.

826 PG&E Opening Brief, pp. 204-205.

cover cost overruns for the Burney Compressor replacement, and for Physical Security and Upgrade Station control programs, not $11.2 million as TURN claims.[827]

TURN does not respond to PG&E's Rebuttal Testimony showing the reprioritization of Los Medanos funding.[828] Instead, TURN continues to insist that PG&E only covered the $11.15 million cost overruns on the Burney compressor station project leaving $45.882 million of the amount authorized for the Los Medanos compressor replacement unaccounted for ($57.032 million minus $11.15 million).[829] As discussed in the previous paragraph, PG&E actually reallocated $47.7 million of Los Medanos funding to other projects as part of the 2019 GT&S case, not $11.15 million as TURN claims.

Moreover, PG&E was overspent across its overall portfolio of work in the 2019 GT&S rate period further demonstrating that the Los Medanos funding was fully reprioritized.[830] Even though PG&E did not perform the Los Medanos Compressor replacement that was funded in the 2015 GT&S rate case, for the 2015-2018 period PG&E forecast total capital expenditures over adopted to be recovered from customers of $52.393 million.[831]

In its testimony, TURN recommended that the $45.882 million of funds remaining from the original authorization for the Los Medanos compressor replacement be credited against the $51.231 million of capital that has been requested again here, leaving a balance of $5.349 million. This recommendation should be rejected for the reasons discussed above.

The Commission should also reject TURN's proposal in its Opening Brief that the balance of $5.349 million from its original recommendation be offset by unused funding from

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827 PG&E-16-E, p. 6-34, lines 19-22.

828 In fact, TURN makes the incorrect assertion that "PG&E has not provided any showing here on how the funding was reallocated and whether such reallocation related to the provision of safe and reliable service." TURN Amended Opening Brief, p. 249.

829 TURN Amended Opening Brief, p. 249.

830 PG&E-16-E, p. 6-34, lines 3-6.

831 A.17-11-009, Exhibit (PG&E-1), p. 4-27, Table 4-3, line 18.

the Tionesta compressor replacement (discussed in Section 3.5.6 below). TURN claims the Tionesta program has remaining "unaccounted-for funding" of $15.2 million, that should be used to offset the remailing $5.3 million of Los Medanos funding so that PG&E would not be allowed any additional funding for the Los Medanos compressor upgrade project, even if the retention of that field is approved.[832] This is not appropriate since no disallowance for the Tionesta project is warranted as discussed in the next section.

3.5.6 GT C&P Compressor Replacements And Retirements: Tionesta Compressor Station Retirement (MAT 76X)

The GT C&P Compressor Replacements and Retirements program is summarized in Section 3.5.5 above. PG&E's 2023 GRC forecast for MAT 76X reflects two projects: (1) Los Medanos K-1 Compressor Replacement, and (2) Tionesta Compressor Station Retirement. Section 3.5.5 addresses the Los Medanos Compressor replacement. The Tionesta Compressor Retirement is addressed in this section.

In the 2019 GT&S rate case, PG&E forecast replacing the Tionesta K-1 compressor unit due to obsolescence. However, based on the results of system planning studies, PG&E now recommends retirement of the Tionesta facility in 2025.[833] PG&E forecasts a total capital expense of $22.960 million for the Tionesta Compressor Station Retirement project for the 2023 GRC period. The cost of retirement is forecast over a 3-year period and includes $9.184 million, $9.184 million, and $4.592 million in 2023, 2024, and 2025, respectively.[834]

TURN recommends a capital disallowance for the entire amount of PG&E's forecast in MAT 76X related to the Tionesta Compressor Station Retirement. PG&E responds to TURN's arguments below.

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832 TURN Amended Opening Brief, p. 250.

833 PG&E Opening Brief, pp. 205-207, Section 3.5.6.

834 PG&E-03-ES, WP 6-38, line 7.

In its Opening Brief, PG&E showed that under the Deferred Work Settlement, cancellation of the Tionesta Compressor replacement as forecast in the 2019 GT&S case does not meet the definition of deferred work.[835] First, although PG&E performed only one of the two imputed units authorized in the 2019 GT&S case under MAT 76X (McDonald Island), there was no deferred work because PG&E is not seeking funding in the 2023 GRC for the second imputed compressor replacement unit that was not performed (Tionesta).[836] Accordingly, the third criteria of the deferred work analysis—"PG&E continues to represent that the curtailed work is necessary" — is not met.

Second, the 2023 requested funding for retirement of the Tionesta compressor is new funding for a different project and work scope. No funding to retire the Tionesta Compressor Station was requested or approved in the 2019 GT&S rate case.[837]

Finally, the adopted funding that was not spent on Tionesta compressor replacement was subject to the overall capital portfolio reprioritization process for Gas Operations as described in PG&E's Summary of Request and Investment Planning opening testimony.[838] For the 2019-2022 GT&S rate case period, PG&E is forecast to incur capital expenditures of $276 million over its 2029 GT&S adopted capital funding.[839] For these reasons, PG&E did not receive a benefit from not spending $22.96 million on the Tionesta Replacement and a disallowance in the 2023 GRC is therefore not warranted.

In its Opening Brief, TURN argues that PG&E is "seeking funding for the same facility in the same program again here."[840] However, PG&E is not seeking funding for the same work

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835 PG&E Opening Brief, p. 206.

836 PG&E-16-E, p. 6-37, lines 14-19.

837 PG&E-16-E, p. 6-38, lines 8-10.

838 PG&E-03, Ch. 2, Section E; PG&E-16-E, p. 6-38, line 32 to p. 6-39, line 2.

839 PG&E-03, p. 2-34, Table 2-8.

840 TURN Amended Opening Brief, p. 243.

that was authorized in the 2019 GT&S case. The retirement of Tionesta compressor station is a different project and work scope from the rebuild of the station that was funded in the 2019 case. Under the explicit language of the deferred work settlement agreement, deferred work only exists if the following criteria are met: "(a) The work was requested and authorized based on representations that it was needed to provide safe and reliable service; (b) PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and (c) PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service."[841] Clearly condition (c) is not met since PG&E is not re-requesting funding for the replacement of the Tionesta compressor station, a project previously funded that has been cancelled and will never be performed. TURN calls this plain reading of the very explicit criteria in the Settlement an "overly narrow interpretation of deferred work."[842] However, TURN has not offered any reason for not following the specific criteria for finding deferred work as set forth in the settlement and adopted by the Commission.

TURN then argues that because the Tionesta project constitutes deferred work (according to TURN), PG&E is required to demonstrate that it reasonably spent the $38.7 million already authorized for the Tionesta Compressor Station in the 2019 GT&S rate case.[843] The deferred work settlement states (emphasis added):

> **for any work that meets these conditions**, PG&E's direct showing in support of the reasonableness of its forecast in the rate case shall . . . explain why the authorized work was not performed in the time forecasted, whether the deferral of the authorized work resulted in lower than authorized spending for the authorized work and, if so, how the funding was reallocated and whether such reallocation related to the provision of safe and reliable service.[844]

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841 PG&E-03, p. 6-102, lines 20-30, citing 2020 GRC Settlement, Section 5.2 "Deferred Work Principles".

842 TURN Amended Opening Brief, p. 245.

843 TURN Amended Opening Brief, pp. 243-244.

844 2020 GRC Settlement Agreement adopted in the final GRC decision, D.20-12-005, Section 5.2 "Deferred Work Principles".

Thus, the requirement to explain "how the funding was reallocated and whether such reallocation related to the provision of safe and reliable service" only applies if the three criteria for deferred work are met. PG&E has applied the criteria in the settlement and the Tionesta compressor replacement project does not meet the conditions since PG&E is not requesting funding for the cancelled project. Accordingly, PG&E is not required by the terms of the settlement to explain how the funding was reallocated.

Nevertheless, as explained above, the adopted funding that was not spent on Tionesta compressor replacement was subject to the overall capital portfolio reprioritization process for Gas Operations. In addition, PG&E is forecast to incur capital expenditures of $276 million over its 2019 GT&S adopted capital funding, despite not spending funding on the Tionesta station rebuild.[845] This shows that the funding was reallocated to other work in the Gas Operations portfolio.

For all these reasons, the Commission should find that no deferred work exists for the Tionesta compressor replacement project, and that PG&E's forecast to fund the Tionesta retirement project should be adopted.

3.6 Asset Family – Storage[846]

PG&E's gas storage asset family includes several asset types: (1) wells and reservoirs for underground storage facilities; (2) surface facilities; and (3) pipelines at the underground storage facilities. PG&E currently operates three storage facilities: McDonald Island, Los Medanos, and Pleasant Creek. In response to our expense and capital forecasts for gas storage, parties have raised issues concerning our updated Peak Day Supply Standard, which addresses the gas capacity needs during the rate case period (2023-2026), our proposal to retain the Los Medanos storage facility, drill new wells and install cross-compression to address identified capacity

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845 PG&E Opening Brief, p. 207.

846 Asset Family –Storage is addressed in Chapter 7 of PG&E's Prepared Testimony, PG&E-03, and further addressed in Chapter 7A and 7B of PG&E's Rebuttal Testimony, PG&E-16-E.

shortfalls, and our forecasts for certain gas storage programs. In this section of our Reply Brief, we address the following issues:

TABLE 3-6
GAS STORAGE DISPUTED ISSUES

Section	Topic	Parties
3.6.1	PG&E's Updated Peak Day Supply Standard	TURN, Wild Goose, and LGS
3.6.2	Curtailment	SCGC/PA and TURN
3.6.3	Issues Raised by Wild Goose and LGS	Wild Goose and LGS
3.6.4	Core Gas Supply Firm Storage	TURN
3.6.5	Well Reworks and Retrofits (Capital MAT 3L3)	TURN
3.6.6	Well Reworks and Retrofits (Expense MAT AH2)	TURN
3.6.7	Well Integrity Assessments (Expense MAT AH1)	TURN
3.6.8	New Storage Well Drilling (Capital MAT 3L1)	TURN
3.6.9	Wells Controls and Monitoring (MAT 3L5)	TURN

3.6.1 PG&E's Updated Peak Day Supply Standard

The Peak Day Supply Standard is a forecast of potential customer demand for natural gas on a "peak day" over a ten-year period and the supply available from either transmission pipelines or storage to meet that demand. A capacity shortfall indicates that supply (*i.e.*, pipeline capacity and storage) is not sufficient to meet potential peak day demand. The Peak Day Supply Standard is critical because it helps with necessary advance planning so that when a peak day event occurs, such as a particularly cold period of time, PG&E has sufficient gas transmission and storage resources available so that it does not have to shut off gas to customers.[847]

PG&E originally presented a Peak Day Supply Standard in its 2019 GT&S rate case, although in that case it was referred to as the "Reliability Standard" or "Reliability Supply Standard."[848] The Peak Day Supply Standard was a key part of PG&E's Natural Gas Storage Strategy or "NGSS" put forward by a number of parties in the 2019 GT&S rate case.[849]

Because the Peak Day Supply Standard in the 2019 GT&S rate case was prepared in 2017, more than five years ago, PG&E prepared an updated Peak Day Supply Standard for this

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847 PG&E Opening Brief, p. 211.

848 PG&E-03, p. 7-47, lines 16-19.

849 PG&E-03, p. 7-47, lines 14-16.

proceeding. PG&E's Opening Testimony included a detailed description of its updated Peak Day Supply Standard and a line by line discussion of the assumptions included in PG&E's updated forecast.[850] The updated Peak Day Supply Standard is intended to ensure that on a peak day for gas demand, PG&E can continue to safely and reliably operate its gas transmission and storage system.

TURN asserts that PG&E's updated Peak Day Supply Standard is "skimpy."[851] This is a surprising argument. In the 2019 GT&S rate case, the Peak Day Supply Standard was described in a single page of testimony, which did not include the type of detailed discussion of underlying assumptions that PG&E has included in this proceeding.[852] TURN was a signatory to the Memorandum of Understanding in that case (2019 GT&S MOU) that was based on the Peak Day Supply Standard. TURN's argument that PG&E's detailed updated Peak Day Supply Standard analysis in this case is "skimpy" is belied by TURN's willingness to sign the 2019 GT&S MOU supported by a single-page Peak Day Supply Standard analysis that was much less robust.

TURN also makes the surprising argument that PG&E's updated Peak Day Supply Standard is "outdated."[853] TURN does not dispute that PG&E used the most current data when it prepared its updated analysis for filing last year. Moreover, any party could always argue that an analysis is "outdated" in a regulatory proceeding given the fact that proceedings often last a year or longer. What is surprising is that TURN argues PG&E's core demand forecast from 2021 is outdated but then suggests that the Commission could use a core demand forecast from 2017.[854] And for electric generation demand, TURN initially argued in its prepared testimony that PG&E's forecast for 2023-2024 in the updated Peak Day Supply Standard should be used

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850 PG&E-03, p. 7-47, line 13 to p. 7-52, line 10.

851 TURN Amended Opening Brief, p. 268.

852 WGL-02, Attachment A, p. 11-25 (attaching testimony from the 2019 GT&S rate case).

853 TURN Amended Opening Brief, p. 269.

854 TURN-07, p. 8, lines 14-16.

but that it should not increase in subsequent years.[855] In short, TURN's stated concerns about the use of "outdated" information seem spurious given TURN's own proposed analysis. We addressed this issue in our Opening Brief as well.[856]

In the remainder of this Section 3.6.1, we address: (1) arguments made by Wild Goose and LGS regarding the quality of the data used in the updated Peak Day Supply Standard; (2) the core customer demand forecast; (3) electric generation demand forecast; (4) TURN's revised Peak Day Supply Standard; and (5) inclusion of Inventory Management and Reserve Capacity in the Peak Day Supply Standard.

3.6.1.1 Wild Goose And LGS Concerns About PG&E's Data For The Updated Peak Day Supply Standard

Wild Goose and LGS raise a number of concerns about the data supporting PG&E's updated Peak Day Supply Standard analysis.[857] These concerns are based on a misunderstanding of the data provided by PG&E or raise classic red herrings.

First, Wild Goose and LGS argue that PG&E has not explained why the demand forecast in the 2019 GT&S rate case was 4,616 MMcf/d, while the demand forecast in this proceeding is 4,190 MMcf/d.[858] These parties argue that if Los Medanos was not needed in the 2019 GT&S rate case, when the demand forecast was higher, why should it be needed now. This argument is readily addressed. In short, Wild Goose and LGS are looking at the wrong numbers. The 4,616 MMcf/d demand forecast from the 2019 GT&S rate case includes <u>both</u> customer demand <u>and</u> Inventory Management and Reserve Capacity.[859] The 4,190 MMcf/d in PG&E's updated Peak Day Supply Standard analysis only includes demand forecasts, it does <u>not</u> include Inventory

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855 TURN-07, p. 10, lines 1-2.

856 PG&E Opening Brief, p. 214.

857 Wild Goose and LGS Opening Brief, pp. 4-8.

858 Wild Goose and LGS Opening Brief, p. 4.

859 D.19-09-025, p. 24, Table 1.

Management and Reserve Capacity.[860] When the 550 MMcf/d for Reserve Capacity and Inventory Management are added in, the total forecast in, the updated Peak Day Supply Standard for winter 2026-2027 would be 4,740 MMcf/d (4,190 + 550 = 4,740), exceeding the demand from the 2019 GT&S rate case. In addition, PG&E's updated Peak Day Supply Standard includes updated supply forecasts that would also impact the identified capacity shortfall.[861]

Second, Wild Goose and LGS repeat their incorrect argument that PG&E's demand forecast is only based on two years of temperature data which they refer to as "paltry."[862] This argument reflects a misunderstanding by Wild Goose's and LGS' witness of a PG&E discovery response. As we explained in our Opening Brief, while our outside experts Marquette Energy Analytics (MEA) use the most recent two years of data to update their previous analyses[863], the underlying analyses includes substantially more than simply two-years of data.[864] As Mr. Graham explained, the MEA analysis includes not only the recent two years of data, but also historical system composite temperatures and system core demand to perform a regression analysis.[865] While the most recent two-years is used to update the peak day demand analysis, it is not the only data the analysis relies on.

Third, Wild Goose and LGS point to a PG&E data response attached to TURN's testimony concerning peak day demand for the past 10 years and assert that PG&E did not include the peak days which occurred in December 2013 and that PG&E's data is "internally inconsistent."[866] This is a red herring. TURN acknowledged in its testimony that PG&E's data

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860 PG&E-03, p. 7-48, Table 7-15, line 5 (2026-2027 winter).

861 PG&E-03, p. 7-49, line 17 to p. 7-50, line 8.

862 Wild Goose and LGS Opening Brief, pp. 2, 4.

863 Tr. Vol. 6, 962:3-11, PG&E/Graham.

864 PG&E Opening Brief, p. 216.

865 PG&E-16-E, p. 7B-11, lines 3-9.

866 Wild Goose and LGS Opening Brief, p. 5, citing TURN-07, Attachment 1, Data Request 115, Question 2, Attachment 1.

response inadvertently excluded November and December data.[867] However, TURN also explained that data provided by PG&E in other data requests included daily core and electric generation demand forecasts for the last 11 years, <u>including</u> November and December data.[868] As a result of the daily demand information provided by PG&E, TURN was able to determine that PG&E's peak demand day for core customers was December 9, 2013. Thus, Wild Goose's and LGS' concerns about inconsistent data are misplaced. PG&E provided sufficient data to enable to parties to determine peak demand days and the inadvertent error in a single data response does not demonstrate an inconsistency.

Fourth, Wild Goose and LGS dispute PG&E's statement in rebuttal testimony that it has seen days with total demand above 4,500 MMcf/d.[869] Again, these parties misunderstand PG&E's testimony. Wild Goose and LGS appear to argue that the 4,500 MMcf/d refers to core customer demand, but a simple review of PG&E's rebuttal testimony makes clear that this number reflects "total demand" not just core demand.[870] And even Wild Goose and LGS concede that total demand has significantly exceeded 4,500 MMcf/d, a fact that PG&E confirmed to these parties in discovery.[871] Wild Goose and LGS argue that certain noncore demand is available and thus can be curtailed. But this isn't the point. PG&E was trying to explain what the total demand was on its system, not whether that demand could be curtailed or not.

Fifth, Wild Goose and LGS argue that PG&E's peak day demand forecast in this proceeding is different than demand forecasts in the GT&S Cost Allocation and Rate Design

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867 TURN-07, p. 7, fn. 9.

868 TURN-07, p. 7, fn. 9.

869 Wild Goose and LGS Opening Brief, pp. 5-7.

870 PG&E-16-E, p. 7B-21, lines 17 (using phrase "total demand").

871 Wild Goose and LGS Opening Brief, p. 6 (conceding that total demand on December 9, 2013 was 4,975 MMcf/d); WGL-04, p. 64.

(CARD) proceeding and the California Gas Report. We addressed this issue in our Opening Brief, where we explained that the CARD proceeding and California Gas Report forecasts used in this comparison were not for peak day demand, but instead reflect average day demand.[872] Our Opening Brief explained the critical distinction between average day and peak day demand and why this comparison by Wild Goose and LGS is apples to oranges.

Finally, Wild Goose and LGS comment on the possibility that DCPP will not retire, and the corresponding impact on the electric generation demand forecast. We addressed this issue in our Opening Brief.[873]

3.6.1.2 PG&E's Core Customer Demand Forecast Is Reasonable

The forecast for core customer demand on a peak day is reflected on Line 1 of PG&E's updated Peak Day Supply Standard included as Table 7-15 in Exhibit PG&E-03, Chapter 7. PG&E's core customer demand forecast was developed by outside experts at MEA using both historical data and the most recent two years of data on core customer demand. MEA also prepared the core customer demand forecast for the 2019 GT&S rate case using the same approach and methodology. Although TURN, Wild Goose, and LGS were parties in the 2019 GT&S rate case proceeding, none of these entities raised any concerns about MEA's methodology or its development of a core customer demand forecast.[874] In fact, in this case, TURN's Opening Testimony offers an alternative forecast using the MEA analysis from 2017 for core customer demand.[875] If TURN believed MEA's forecasts were flawed, why did it suggest using earlier MEA forecasts as a potential ceiling for core demand?

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872 PG&E Opening Brief, p. 215 (explaining the difference between average and peak day forecasts), pp. 221-222 (explaining the difference in CARD proceeding and California Gas Report forecasts).

873 PG&E Opening Brief, pp. 219-220.

874 PG&E Opening Brief, pp. 215-216.

875 TURN-07, p. 8, lines 14-16.

TURN, Wild Goose and LGS raise a number of issues related to the core customer demand forecast that were addressed in our Opening Brief.[876] Below, we address some of the additional issues raised by these parties in their Opening Briefs.

3.6.1.2.1 Core Customer Demand Issues Raised By TURN

TURN asserts that PG&E's core customer demand forecast was taken directly from the 2020 California Gas Report.[877] However, as we explained above, the core customer demand forecast was based on MEA's detailed analysis using both historical and current information.[878] In the 2019 GT&S rate case, TURN did not have any concerns about MEA's forecasting methodology and, in fact, TURN's Opening Testimony in this proceeding proposes potentially using MEA's 2017 core customer demand forecast as a ceiling.[879] Given this, it is unclear why TURN does not want to use MEA's more recent forecast.

TURN also argues that the highest peak core customer demand during the last 10 years occurred on December 8, 2013, and that the demand on this day should be used in PG&E's analysis, rather than the MEA forecast.[880] This concern is readily addressed. As PG&E's witness Roger Graham explained at the hearing, there are numerous reasons why the peak day core demand forecast would be higher than a date which occurred almost a decade ago (*i.e.*, December 2013) including the undisputed fact that PG&E has interconnected thousands of new core customers in the intervening decade.[881]

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876 PG&E Opening Brief, pp. 215-218.

877 TURN Amended Opening Brief, p. 269.

878 PG&E-16-E, p. 7B-10, line 29 to 7B-11, line 1.

879 TURN-07, p. 8, lines 14-16.

880 TURN Amended Opening Brief, p. 270.

881 Tr. Vol. 6, 972:18 to 973:6, 973:19 to 974:10, PG&E/Graham; see also PG&E Opening Brief, pp. 216-218.

TURN also raises questions as to why peak day demand would be increasing when average demand for core customers is decreasing, and the impact of energy efficiency.[882] These issues were addressed in our Opening Brief.[883] TURN fails to offer any evidence of its own to demonstrate that peak day demand is decreasing, nor did TURN retain an expert like MEA to offer an opinion on peak day demand. Instead, TURN simply speculates that peak day demand should be decreasing, without any evidence to support this speculation. TURN's position regarding a correlation between average usage and peak day demand is also disputed by Wild Goose and Lodi, as explained in Section 3.6.1.2.2 below.

TURN argues that no witness from MEA was provided at the hearing and MEA's analysis is proprietary.[884] Notably, TURN did not ask detailed discovery questions regarding MEA's analysis and since TURN signed a confidentiality agreement, if it had asked it likely could have been provided with more information about MEA's model and underlying assumption. One of TURN's discovery requests about the MEA analysis was propounded on August 16, 2021 and responded to on August 30, 2021, almost a year before the 2022 hearings in this proceeding. TURN had more than a year to ask additional discovery regarding the MEA analysis, but it completely failed to do so.[885] Instead, TURN waited until the last minute, on the day Mr. Graham was cross-examined, to ask more detailed questions about MEA's analysis.

TURN also states that Mr. Graham was not familiar with MEA's methods and then selectively edits a quote from the hearing.[886] The complete text is:

> Q Okay.· Now, is it correct to say that the MEA analysis uses a lineal regression?
>
> A I'm not exactly sure of the techniques they used to make this --

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882 TURN Amended Opening Brief, pp. 270-271.

883 PG&E Opening Brief, pp. 215-216.

884 TURN Amended Opening Brief, p. 272.

885 PG&E-16-E, Appendix A, pp. AppA-321 to AppA-339.

886 TURN Amended Opening Brief, p. 272.

Q Okay. Well, on page 322 in attachment to the data response, you have several lines shown on the graph there.· Did PG&E use one of those lines in particular for purposes of developing its forecast?

A I believe we used the most current line.[887]

Mr. Graham's testimony was narrowly focused on the specific type of regression technique used by MEA, not MEA's entire analysis.

Finally, TURN argues that PG&E's reliance on the MEA analysis is uncorroborated hearsay evidence.[888] *TURN v. PUC*, 223 Cal.App.4th 945 (2014) (*TURN*), cited in TURN's Opening Brief, makes clear that hearsay evidence is admissible in Commission proceedings.[889] In *TURN*, PG&E had requested official notice of certain documents from the CAISO and the California Energy Commission (CEC) but did not offer any witness to sponsor these documents or provide testimony concerning them.[890] Thus, the documents were uncorroborated hearsay.

The facts here are completely different. PG&E did not simply ask the Commission to take official notice of the MEA analysis with no witness to offer or support that analysis. Instead, Mr. Graham offered testimony regarding the MEA analysis[891] and sponsored discovery requests that include the underlying data used in the MEA analysis as well as the MEA results.[892] Mr. Graham also sponsored discovery requests in response to Wild Goose and LGS that explained the time period for the data used in the MEA analysis.[893] All of these data request responses are in evidence in this proceeding and were provided well in advance of the hearing. At the hearing, Mr. Graham responded to questions regarding the MEA analysis and

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887 Tr. Vol. 6, p. 965:4-15, PG&E/Graham.

888 TURN Amended Opening Brief, p. 273.

889 TURN Amended Opening Brief, p. 273, fn. 807; *TURN*, 223 Cal.App.4th at 959-960 (hearsay evidence admissible in Commission proceedings).

890 *TURN*, 223 Cal.App.4th at 953.

891 PG&E-16-E, p. 7B-10, line 23 to p. 7B-11, line 17.

892 PG&E-16-E, Appendix A, pp. AppA-321 to AppA-339.

893 WGL-01, Attachment B.

how it was used by PG&E.[894] Simply because Mr. Graham was unable to answer a single question about a specific regression analysis technique used by MEA does not mean that MEA's analysis is uncorroborated hearsay. Rather, Mr. Graham corroborated the MEA analysis. TURN's desperate last-minute attempt to have the Commission disregard the MEA analysis simply reflects the fact that the MEA analysis conclusively supports PG&E's position.

3.6.1.2.2 Core Customer Demand Issues Raised By Wild Goose And LGS

Contradicting TURN, Wild Goose and LGS agree that customer behavior and demand on peak days (*i.e.*, days of extreme cold) will be different than the demand and behavior during average days.[895] Wild Goose and LGS question, however, why the core customer demand in PG&E's updated Peak Day Supply Standard is higher than the December 9, 2013 peak day demand.[896] The answer to this question is straightforward. As Mr. Graham testified at the hearing, there are numerous reasons for increases in core customer peak demand most notably that in the nearly decade of time that has elapsed since 2013, PG&E has connected thousands of additional core customers.[897] Given that there are thousands of additional customers now being served, one would naturally expect the peak day demand for core customers to increase beyond the 2013 levels during a similar cold-day event.

3.6.1.3 PG&E's Electric Generation Demand Forecast Is Reasonable

The electric generation gas demand forecast included in the Peak Day Supply Standard is located on Line 3 of Table 7-15 in Exhibit PG&E-03. TURN, Wild Goose and LGS raise a number of issues regarding the electric generation demand forecast which we addressed in our

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894 Tr. Vol. 6, 962:1 to 963:3, 963:22 to 966:2, PG&E/Graham.

895 Wild Goose and LGS Opening Brief, p. 9 ("While it may be true that peak day demand is governed by different parameters and customer behavior than average demand, the record still shows that the highest peak day core demand in the last decade was 2,384 MMcf/d on December 9, 2013.").

896 *Id.*

897 Tr. Vol. 6, 972:18 to 973:6, 973:19 to 974:10, PG&E/Graham.

Opening Brief.[898] Most of the arguments raised by these parties in their Opening Briefs have already been addressed. However, there are several arguments that require an additional response.

TURN expresses some confusion regarding which electric generation forecast is being offered by PG&E in this proceeding. The forecast included in PG&E's updated Peak Day Supply Standard was based on the best information available at the time and, in testimony, PG&E explained how this forecast was developed.[899] PG&E provided additional information in discovery, including data regarding all of the new gas-fired generation included in PG&E's forecast[900] and a detailed description of how electric generation demand was calculated.[901] In its testimony, TURN argued that PG&E's electric generation forecast was inconsistent with the average demand data in the 2020 California Gas Report.[902] TURN also argued that PG&E's analysis did not include the Preferred System Plan adopted by the Commission in D.22-02-004.[903] In response to these arguments, Mr. Graham offered the <u>2022</u> California Gas Report which included assumptions from the Preferred System Plan and noted that the electric generation demand forecasts in the updated 2022 California Gas Report are in fact higher than the forecasts used in our updated Peak Day Supply Standard.[904] This was offered for purposes of comparison and to rebut TURN's argument about PG&E's forecast not considering the Preferred System Plan. PG&E did not, however, offer the 2022 California Gas Report as the basis for a new forecast. Mr. Graham made this clear at the hearing:

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898 PG&E Opening Brief, pp. 218-222.

899 PG&E-03, p. 7-49, lines 6-12.

900 TURN-07-Atch1, response to TURN_003-Q36.

901 TURN-07-Atch1, response to TURN_003-Q35.

902 TURN-07, p. 12, lines 3-10.

903 TURN-07, p. 8, lines 18-22.

904 PG&E-16-E, p. 7B-12, line 17 to p. 7B-13, Table 7B-1.

Q Have these new forecasts been approved by any governmental agency?

A No.· And my testimony is not adopting these forecasts.· I present it as an alternative to the criticism that was levied on our electric gen forecast, but it didn't use some of the more recent inputs that are available for the electric gen like the preferred resource and those types of things. So I offered this as an alternative so it's not PG&E's proposal.· PG&E still stands by its original forecast in this case.[905]

TURN's apparent confusion as to which forecast PG&E is using was clearly addressed at the hearing.

TURN argues that there are differences between the data reflected in the 2022 California Gas Report and PG&E's Peak Day Supply Standard.[906] While true, this does not change PG&E's underlying analysis. As explained above, the 2022 California Gas Report was included in our Rebuttal Testimony in response to TURN's arguments for comparison purposes. PG&E has not proposed using it for the electric demand forecast included in the Peak Day Supply Standard.

TURN proposes as an alternative an electric generation forecast based on the 2020 California Gas Report.[907] There are several problems with this proposal. First, the 2020 California Gas Report is now out of date, superseded by the 2022 California Gas Report. If TURN wants to rely on the California Gas Report, it should rely on the most up to date version, which PG&E provided in Rebuttal Testimony.[908] Second, TURN alternatively criticizes the California Gas Report and then relies on it.[909] Third, TURN uses average monthly peak electric generation demand rather than peak day demand.[910] Averaging peak demand over a month results in a lower peak day demand. However, it is the peak day demand that PG&E needs to

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905 Tr. Vol. 6, 975:8-19, PG&E/Graham.

906 TURN Amended Opening Brief, pp. 275-276.

907 TURN Amended Opening Brief, pp. 277-278.

908 PG&E-16-E, p. 7B-13, Table 7B-1.

909 TURN-07, p. 6, lines 16-19.

910 TURN Amended Opening Brief, p. 278.

address, not an average.[911] In short, TURN's proposal is based on outdated data, is from a source that TURN criticizes, and is based on averages over a month rather than peak days.

Wild Goose and LGS argue that PG&E's electric generation demand forecast is "excessive" citing the 2020 California Gas Report. As we explained in our Opening Brief, the numbers cited by Wild Goose and LGS from that report are for average demand, not peak day demand.[912] Wild Goose and LGS also cite average day demand forecasts from the CARD proceeding.[913] The flaws in this argument are discussed above in Section 3.6.1.1.

3.6.1.4 TURN's Revised Peak Day Supply Standard

Based on its proposals, TURN presents a revised Peak Day Supply Standard.[914] There are several important flaws with TURN's analysis.

First, in addition to core customer demand and electric generation demand, a third important part of the Peak Day Supply Standard is industrial demand.[915] TURN did not dispute PG&E's industrial demand forecast in its Opening Testimony.[916] However, in its Opening Brief, TURN now argues that the 2022 California Gas Report forecast for industrial demand should be adopted for the Peak Day Supply Standard because it is lower than the forecast used by PG&E in its Opening Testimony.[917] This is simply cherry-picking. TURN criticizes the use of the 2022 California Gas Report forecast for electric generation because it is higher than the electric generation demand forecast in PG&E's Opening Testimony but then, when the forecast for industrial demand in the 2022 California Gas Report is lower, TURN embraces it. Notably,

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911 Tr. Vol. 6, 982:1-5, PG&E/Graham.

912 PG&E Opening Brief, pp. 221-222.

913 Wild Goose and LGS Opening Brief, p. 10.

914 TURN Amended Opening Brief, pp. 280-281.

915 PG&E-03, p. 7-48, Table 7-15, line 2.

916 TURN Amended Opening Brief, p. 279.

917 TURN Amended Opening Brief, p. 279.

when all four demand forecasts in the 2022 California Gas Report are considered, it exceeds the demand forecast in PG&E's Opening Testimony.[918]

Second, TURN's analysis uses its flawed forecasts for core customer demand and electric generation demand. These issues are addressed in Sections 3.6.1.2 and 3.6.1.3 above.

3.6.1.5 Inclusion Of Inventory Management And Reserve Capacity In The Peak Day Supply Standard

Wild Goose and LGS argue that PG&E's Inventory Management and Reserve Capacity services provide sufficient backup capacity.[919] However, PG&E can only provide these services if it has sufficient storage capacity. The Inventory Management and Reserve Capacity services are included in the updated Peak Day Supply Standard as a part of the overall storage need.[920] Providing these services creates in part the capacity shortfall that we are proposing to address, in part, by the retention of Los Medanos.[921] In addition, it is notable that while TURN and SCGC/PA propose eliminating Reserve Capacity, Wild Goose and LGS appear to support this service and indicate that it provides "sufficient backstop capacity."[922]

3.6.2 Curtailment

PG&E's updated Peak Day Supply Standard includes two services intended to ensure gas system reliability – Inventory Management and Reserve Capacity.[923] Inventory Management is 300 MMcf/d and Reserve Capacity is 250 MMcf/d for a total of 550 MMcf/d. Both of these

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918 Compare PG&E-03, p. 7-48, Table 7-15, line 5 (PG&E total demand forecast) to PG&E-16-E, p. 7B-13, Table 7B-1, line 5 (2022 CGR total demand forecast).

919 Wild Goose and LGS Opening Brief, pp. 10-11.

920 PG&E-03, p. 7-48, Table 7-15, line 15 (Inventory Management and Reserve Capacity).

921 PG&E-03, p. 7-48, Table 7-15, line 18 (capacity shortfall).

922 Wild Goose and LGS Opening Brief, p. 10.

923 PG&E-03, p. 7-48, Table 7-15, line 15; p. 7-50, lines 11-15; p. 7-54, lines 13-29.

services and the corresponding amounts were approved by the Commission in the 2019 GT&S rate case.[924] No party disputes the need for or the amount of Inventory Management.

SCGC/PA and TURN do dispute the need for and amount of Reserve Capacity. These parties assert that Reserve Capacity can be eliminated or reduced if PG&E revises its curtailment protocols. Eliminating or reducing Reserve Capacity would decrease the capacity shortfall identified in PG&E's updated Peak Day Supply Standard.[925] SCGC/PA and TURN argue that if Reserve Capacity is eliminated or reduced and the corresponding capacity shortfall decreases, the Los Medanos storage facility is not needed and/or other work to address the capacity shortfall, such as drilling new wells, may not need to be performed.[926] Below, we address SCGC/PA's arguments in Section 3.6.2.1 and TURN's arguments in Section 3.6.2.2.

3.6.2.1 Curtailment Issues Raised By SCGC/PA

3.6.2.1.1 The Number Of Potential Curtailments Is Substantial

SCGC/PA initially try to downplay the importance of and need for Reserve Capacity. To do so, however, SCGC/PA selectively quote facts that do not tell the entire story. For example, SCGC/PA allege that Reserve Capacity is intended to address unplanned maintenance outages and that this type of outage occurred "on only about fourteen percent of the days during the five years 2013-2018" and only one of those outages occurred on a peak day.[927] SCGC/PA argue that if Reserve Capacity is eliminated and replaced by curtailments, that curtailments would be infrequent given the limited number of unplanned maintenance outages.

As a preliminary matter, potential curtailments resulting from unplanned outages on 14% of the days during a year is a substantial amount, and although unplanned outages may happen

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924 D.19-09-025, p. 24, Table 1 and pp. 34, 40.

925 See PG&E-03, p. 7-48, Table 7-15. If the Reserve Capacity included on Line 15 is reduced or eliminated, this reduces the total withdrawal needed on Line 16 and correspondingly reduces the capacity shortfall on Line 18.

926 SCGC/PA Opening Brief, pp. 11-12.

927 SCGC/PA Opening Brief, p. 3.

on a limited number of peak days, the number of potential curtailments can still be substantial. More importantly, Reserve Capacity is used for significantly more types of events than just for unplanned maintenance outages. Reserve Capacity also addresses forecasting errors, reduction of the supply at an interconnection, pipeline outages, and demand forecast uncertainty.[928] Thus, the number of events addressed by Reserve Capacity is likely substantially higher than the 14% cited by SCGC/PA. SCGC/PA's exclusive focus on unplanned maintenance outages, which are a subset of the events addressed by Reserve Capacity, does not tell the entire story of potential curtailments if Reserve Capacity is eliminated.[929]

In addition, if Reserve Capacity is replaced by curtailments, the number of curtailments will likely be substantially higher than the number of events where Reserve Capacity would actually have been used. Reserve Capacity is available in real time to meet operational needs. Thus, if an event is forecasted to occur, but the event does not materialize, there is no impact on customers because the Reserve Capacity was available but did not need to be used. Curtailments, on the other hand, are based on advance notice to customers to curtail their gas usage. As Mr. Graham explained, to be effective curtailments must be called sufficiently in advance of a potential shortage event.[930] As a result, even if the actual number of events in a given year where curtailment is needed are relatively low, the number of curtailments called will likely be much higher. Mr. Graham's undisputed testimony demonstrated that PG&E would likely need to call <u>70 curtailments per year</u> when the circumstances and forecasts indicate a potential shortage.[931] Thus, SCGC/PA's assertion that calling curtailments would be "rare" is unfounded and contrary to the undisputed evidence.[932]

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928 PG&E-16-E, p. 7B-4, line 26 to p. 7B-5, line 12.

929 *Id.*

930 PG&E-03, p. 7-56, lines 17-30.

931 PG&E-03, p. 7-58, lines 1-9.

932 SCGC/PA Opening Brief, p. 3.

3.6.2.1.2 The Curtailment Protocols Advocated By SCGC/PA May Have Adverse Consequences

After discussing the potential for and number of curtailments, SCGC/PA then discuss PG&E's current Gas Rule 14 curtailment procedures. Gas Rule 14 has been approved by the Commission and includes well-established curtailment protocols dating back more than 20 years. These curtailment protocols balance the interests of various customers including gas-fired generators, non-core industrial and commercial customers, and core residential customers. As the Commission explained some time ago when gas-fired generators proposed changing Gas Rule 14 to prioritize gas-fired generators during potential curtailment events, "the process leading up to the curtailment and diversion priorities contained in the PG&E Gas Accord [*i.e*, gas Rule 14] was not developed overnight. These priorities should not be changed without a thorough evaluation of the ramifications resulting from the proposed modification … ."[933]

SCGC/PA recognize that the current Gas Rule 14 does not allow sufficient time for curtailments that could eliminate the need for Reserve Capacity.[934] Thus, SCGC/PA suggest that PG&E adopt a new approach based on curtailment protocols adopted by SoCalGas.[935] We addressed the problems resulting from SoCalGas' curtailment protocols in our Opening Brief, including statements by SCGC in a separate Commission proceeding expressing concern about the impact of SoCalGas' protocols.[936]

The evidence that SCGC/PA rely on to support their claim that SoCalGas' curtailment protocols are effective actually tells the exact opposite story.[937] The Commission Staff Report

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933 D.02-02-008, p. 15.

934 SCGC/PA Opening Brief, p. 4.

935 SCGC/PA Opening Brief, pp. 4-6.

936 PG&E Opening Brief, pp. 228-229.

937 SCGC/PA Opening Brief, p. 5, fn. 13 (citing SCGC/PA-01[-E], Attachment G, as support concerning the effectiveness of SoCalGas curtailment protocols).

relied on by SCGC/PA highlights the price spikes and reliability impacts on the SoCalGas system after curtailment was implemented:

> Limited gas supply caused by the constraints on the SoCalGas system had caused both gas and electricity prices to spike on high demand, hot days in summer 2018, leading to concerns that similar spikes would occur on high demand, cold days in the winter. However, the early winter was relatively warm, and SoCalGas was initially able to meet demand with flowing supplies from the pipelines and withdrawals from its non-Aliso gas storage fields: Honor Rancho, Playa del Rey, and La Goleta.
>
> In contrast, the latter half of the winter brought variable conditions then a prolonged stretch of cold weather, culminating in a February that the National Weather Service declared the coldest since 1962. Complicating gas supply concerns was the fact that weather forecasts repeatedly failed to accurately predict the weather. Uncertainty and cold weather contributed to gas price spikes across the country, including in the SoCal Border and SoCal Citygate markets. <u>As a result, electricity prices in California experienced major price hikes as well. The continuous wave of cold weather strained the SoCalGas system as demand for natural gas grew more rapidly than expected</u>.[938]

Commission Staff then concludes:

> For instance, comparing the two-week winter 2017-18 cold snap to this past winter's February weather <u>highlights the significance of ample gas storage</u>, the impact of ramping hours on system conditions, and the cascading effects of gas supply shortages on electricity prices.[939]

Thus, contrary to SCGC/PA's assertion, services such as Reserve Capacity and the corresponding storage needed to provide Reserve Capacity are essential to gas system reliability.

SCGC/PA point to SoCalGas curtailments that occurred in February 2019 as an example of effective curtailments.[940] Again, this does not tell the full story. While SoCalGas did curtail electric generators in February 2019 to address demand on peak days, these curtailments came with consequences. As the Commission Staff explained in a subsequent report:

> Gas and electric prices were lacked the volatile swings seen in winter 2019-20. The peak gas price of $6.74/MMBtu occurred on November 22, 2019, and <u>is significantly lower than the peak price of $26/MMBtu seen last winter on February 18, 2019</u>. <u>During winter 2018-19, the highest daily average electricity</u>

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938 SCGC/PA-01-E, Attachment G, p. 4 (emphasis added).

939 SCGC/PA-01-E, Attachment G, p. 5 (emphasis added).

940 SCGC/PA Opening Brief, p. 6.

price was almost $146/MWh on February 22, 2019, during a sustained cold snap, Stage 4 OFO, and a mandatory curtailment of electric generation. On the other hand, this winter's highest daily average electricity price of $51.25/MWh occurred on November 22, 2019. Furthermore, SoCalGas did not declare any voluntary or mandatory curtailments of electric generation this winter.[941]

In other words, SoCalGas' curtailments along with the peak day gas demand likely resulted in electric generation prices that were nearly 200% higher than prices later in the year. SCGC/PA's assertion that curtailment is a panacea that will allow for the elimination of Reserve Capacity ignores the potential adverse impacts of curtailments.

SCGC/PA assert that PG&E has a sufficient number of large electric generation customers to replace Reserve Capacity with curtailment of electric generation facilities.[942] However, this ignores the explanation that we provided in Opening and Rebuttal Testimony, and summarized in our Opening Brief, that there are a number of reasons that real-time curtailment which is needed to replace Reserve Capacity will not work on PG&E's system.[943] Moreover, it is notable that SCGC/PA did not consult with any electric generation customers as to how SCGC/PA's proposed curtailment protocols would impact these customers.[944] SCGC/PA's proposal to curtail electric generation customers, without their input and despite what has happened with SoCalGas curtailments, is neither reasonable nor prudent and this proposal should be rejected.

3.6.2.1.3 Impact On PG&E's Request In This Proceeding

Finally, it is important to note that SCGC/PA candidly acknowledge that if their curtailment proposal is adopted, this will not address the entire gas capacity shortfall identified in

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941 CPUC, *Winter 2019-2020 SoCalGas Conditions and Operations Report* (Dec. 15, 2020), <https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/winter2019-20lookbackreport-final.pdf> (as of Dec. 6, 2022) (emphasis added).

942 SCGC/PA Opening Brief, p. 6.

943 PG&E Opening Brief, pp. 226-227.

944 PG&E-36, SCGC/Palo Alto response to PG&E_SCGC-PA003-Q05.

PG&E's updated Peak Day Supply Standard analysis.[945] To address the Peak Day Supply Standard capacity shortfall, PG&E proposed: (1) retaining Los Medanos; (2) drilling new wells at McDonald Island and Gill Ranch; and (3) cross-compression.[946] SCGC/PA recognize that curtailment only gets you part way to addressing the capacity shortfall and that either retaining Los Medanos or new well drilling and compression will be necessary.[947] This is in contrast to other parties, such as TURN, who advocate that Los Medanos be sold or decommissioned and that no new drilling or cross-compression is needed. We strongly believe that retention of Los Medanos, drilling new wells, and cross-compression are all needed mitigations. The Commission should approve the necessary investments associated with PG&E's proposal.

3.6.2.2 Curtailment Issues Raised By TURN

TURN's arguments largely mirror SCGC/PA.[948] TURN argues that PG&E should model its curtailment process after SoCalGas but ignores the problems the SoCalGas protocols have created.

3.6.3 Issues Raised by Wild Goose And LGS

Wild Goose and LGS raise a number of issues that primarily focus on the retention of PG&E's Los Medanos facility and the updated Peak Day Supply Standard. Below, we address: (1) comments regarding the Natural Gas Storage Strategy or "NGSS" adopted in the 2019 GT&S rate case; (2) comments regarding Wild Goose and LGS drilling and retrofit costs; (3) allegations that PG&E's proposal is anti-competitive; and (4) the Redwood Constraint and Independent Storage provider (ISP) alternatives. TURN also raises a brief argument regarding ISP alternatives which we address below as well.

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945 SCGC/PA Opening Brief, p. 11.

946 PG&E-03, p. 7-52, line 23 to p. 7-53, line 17.

947 SCGC/PA Opening Brief, p. 11.

948 TURN Amended Opening Brief, pp. 282-283.

3.6.3.1 Comments Regarding The 2019 GT&S Natural Gas Storage Strategy

Wild Goose and LGS argue that in the 2019 GT&S rate case, PG&E made a "compelling case" for divesting Los Medanos.[949] However, these parties ignore the clear admonition of the Commission in that proceeding:

> Accordingly, to decommission Los Medanos, PG&E must file a Tier 2 Advice Letter on or after December 31, 2021, demonstrating that it has the requisite storage capacity to operate without the Los Medanos storage field. Until the PG&E's Tier 2 Advice Letter is approved, PG&E is not permitted to remove more than half of the working gas at Los Medanos or sell or begin decommissioning activities at Los Medanos.[950]

The Commission was well aware when the 2019 GT&S rate case decision was issued that the forecasts for gas storage needs and capacity shortfalls were fluid as a result of regulatory uncertainty and other issues and thus required that before decommissioning or selling Los Medanos, PG&E demonstrate that the facility was no longer needed.[951] Consistent with the Commission's direction, we undertook an updated Peak Day Supply Standard analysis for this proceeding.[952]

Because the 2019 NGSS was based on data from 2017 and earlier, it was entirely reasonable to update the data and the analysis for this proceeding. Our updated analysis indicated exactly what the Commission had feared, that there is not sufficient storage capacity to operate the natural gas system without Los Medanos. As PG&E explained in its Opening Testimony, one of the primary drivers for changes between the 2019 NGSS and the updated Peak Day Supply Standard is the impact of the CalGEM inspection requirements and associated outage impact, which occurred after the 2019 GT&S rate case decision was issued.[953] Based on our updated analysis and forecast, which incorporates an optimistic view of these recent

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949 Wild Goose and LGC Opening Brief, pp. 11-13.

950 D.19-09-025, p. 72.

951 D.19-09-025, pp. 71-72 (describing uncertainty).

952 PG&E-03, p. 7-47, lines 14-24.

953 PG&E-03, p. 7-51, line 25 to p. 7-52, line 10.

CalGEM requirements, we are proposing to retain Los Medanos. Wild Goose and LGS are proposing that the Commission simply turn a blind eye to the reality of the regulatory impacts that have occurred since 2019. The Commission should reject this approach.

Wild Goose and LGS also argue that, in light of the 2019 NGSS, PG&E's proposal to undertake capital improvements at Los Medanos is not reasonable.[954] However, if the Los Medanos facility is needed, which the evidence clearly demonstrates that it is, PG&E cannot simply ignore regulatory and operational needs for the facility. In this proceeding, PG&E is proposing a number of critical capital upgrades that are necessary to keep the Los Medanos facility operational and in compliance with regulatory requirements. First, PG&E is proposing to perform reworks and retrofits to wells at Los Medanos. It is undisputed that these reworks and retrofits are required by CalGEM regulations. Second, PG&E is proposing to replace the operational controls at Los Medanos, which are now past their useful life and are critical for well control systems.[955] Finally, PG&E is proposing to replace the compressor at Los Medanos which is now obsolete.[956] No party disputes the need for these capital upgrades to the Los Medanos facility if it is retained.

3.6.3.2 Comments Regarding Drilling And Retrofit Costs

Wild Goose and LGS assert that PG&E's costs for well drilling and retrofits are too high.[957] However, other than comparing PG&E's costs to their own costs, these parties offer no evidence that PG&E's costs are unreasonable; nor do they make any effort to address the cost information provided in PG&E's testimony and workpapers. More importantly, Wild Goose and LGS ignore the undisputed fact that PG&E's gas storage facilities have deeper storage formations and are laid out differently than the Wild Goose and LGS facilities, which naturally

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954 Wild Goose and LGS Opening Brief, pp. 14-15.

955 PG&E-03, p. 7-43, lines 3-10.

956 PG&E-03, p. 6-32, lines 7-21.

957 Wild Goose and LGS Opening Brief, pp. 14-15.

results in higher costs for PG&E to perform drilling and retrofits.[958] One would expect that given the differences in facility characteristics, the drilling and re-work costs would be different. As PG&E witness Lucy Redmond explained:

> Drilling and conversion costs will necessarily vary based on a number of factors which includes those identified above [*i.e.*, shallower formations and facility layout]. The fact that one storage field operator has estimated costs that are lower than PG&E's cost forecasts does not demonstrate that PG&E's cost forecasts are unreasonable.[959]

The fact that PG&E's costs are different than Wild Goose and LGS does not make our costs unreasonable.

3.6.3.3 PG&E's Proposal Is Not Anti-Competitive

Wild Goose and LGS argue that PG&E's proposed capital upgrades are front-loaded.[960] However, the timing of the reworks and retrofits is required by CalGEM regulation and the replacement of obsolete equipment is necessary to ensure there is not a breakdown of critical facility equipment. PG&E's proposals are necessary to meet regulatory requirements or operational needs, not for an anti-competitive purpose as Wild Goose and LGS imply. Further, Wild Goose and LGS are well aware of these regulatory requirements as they are also subject to the same requirements under CalGEM.

Wild Goose and LGS also assert that the Commission "should not permit PG&E to invest ratepayer funds in the construction of substantial excess capacity that will not be needed for core storage or for park and loan services."[961] The problem with this argument is that PG&E is not proposing to construct substantial excess capacity. The Los Medanos facility is an existing storage facility that has been operating for decades. PG&E is simply proposing to retain this facility to meet clearly demonstrated capacity shortages during the rate case period (2023-2026)

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958 PG&E-16-E, p. 7A-9, lines 12-28.

959 PG&E-16-E, p. 7A-10, lines 4-7.

960 Wild Goose and LGS Opening Brief, p. 15.

961 Wild Goose and LGS Opening Brief, p. 18.

and to perform the capital upgrades needed to keep the facility compliant with regulations and operating reliably.

Wild Goose and LGS argue that PG&E's rates for park and lend services may undercut independent storage producer or "ISP" prices.[962] There are several flaws with this argument. First, as we explained in our Opening Brief, PG&E's park and lend service rates are approved by the Commission. If Wild Goose and LGS believe that PG&E's park and lend pricing is below market, they can address that issues with the Commission which approved PG&E's rates.[963] It is not reasonable, however, to advocate for the sale or decommissioning of Los Medanos, an existing facility that is critical for system reliability, simply because Wild Goose and LGS believe park and lend rates should be higher. In their Opening Brief, Wild Goose and Lodi argue that parking and lending rates are based on existing market circumstances.[964] If Wild Goose and LGS believe those circumstances have changed, they can certainly propose through a petition or other regulatory proceeding that the Commission change PG&E's park and lend service rates.

Second, as Wild Goose and LGS concede, PG&E's park and lend rates provide a <u>minimum</u> charge.[965] However, PG&E may and often does charge more than this amount.[966] The evidence cited in Wild Goose's and LGS' Opening Brief makes this clear. On page 16 of their Opening Brief, Wild Goose and LGS provide PG&E's park and lend transaction volume and average weighted price for a 3½ year period between January 1, 2019 and July 19, 2022. Dividing the total revenue based on volume and price by the total volume results in an average

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962 Wild Goose and LGS Opening Brief, p. 16.

963 PG&E Opening Brief, pp. 239-240.

964 Wild Goose and LGS Opening Brief, p. 18.

965 Wild Goose and LGS Opening Brief, p. 16.

966 Pricing information for specific transactions is confidential, as PG&E indicated to Wild Goose and LGS. See WGL-04, p. 6.

price for park and lend services of $0.16/Decatherm (Dth). This is 60% higher than the assumed average price of $0.10/Dth referred to by Wild Goose and LGS that PG&E had used for its analysis of various options to address the capacity shortfall.[967] This is also higher than the minimum price established by the tariff. In short, actual prices for transactions are often higher than the minimum tariff price cited to by Wild Goose and LGS or the assumed price used by PG&E in its options analysis.

Third, while Wild Goose and LGS recognize that PG&E's park and lend service has a "price floor" (*i.e.*, minimum price),[968] ISPs do not have a price floor for similar services. Thus, contrary to Wild Goose and LGS' argument, ISPs can undercut PG&E's prices for park and lend and, because PG&E's prices are regulated, it cannot reduce its price below the price floor. Notably, Wild Goose and LGS have not offered any evidence in this proceeding as to the prices they offer for similar services and thus the Commission has no evidence on which to weigh these parties' claims that PG&E is undercutting their prices.

Finally, Wild Goose and LGS argue that there will be excess storage capacity based on a park and lend analysis that these parties are just now introducing in their Opening Brief.[969] Wild Goose's and LGS' analysis was not included in their testimony, nor did they conduct any cross-examination on this issue at the hearing. More importantly, the Wild Goose and LGS analysis is not looking at physical capacity and needs for storage, which is the focus of the updated Peak Day Supply Standard analysis and of PG&E's proposal to retain Los Medanos. Instead, their analysis is just looking at what capacity is available for storage customers to obtain park and lend services. Moreover, the Wild Goose and LGS analysis is limited to a single winter

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967 In their Opening Brief, Wild Goose and LGS refer to an average price of $0.010/Dth used in PG&E's analysis of options. See Wild Goose and LGS Opening Brief, p. 16. This appears to be a typo because the workpaper cited by Wild Goose and LGS in footnote 59 of their brief refers to an assumed average price of $0.10/Dth. See PG&E-03, WP 7-61.

968 Wild Goose and LGS Opening Brief, p. 16.

969 Wild Goose and LGS Opening Brief, pp. 16-17.

2022-2023, rather than the entire time period of this rate case (2023-2026).[970] The Wild Goose and LGS analysis is also flawed because while they assert that PG&E will have excess capacity to make available for park and lend services, they then assert in a single sentence, with no evidentiary support, that "[t]his excess capacity, priced at extremely low park and lend tariff rates, does represent a competitive threat to ISPs."[971] But Wild Goose and LGS offer no evidence to support this statement and fail to provide any evidence about their own pricing or the capacity they have available to market.

In short, Wild Goose and LGS' assertions regarding anti-competitive pricing are based primarily on assertions of potential harm, unsupported by any evidence, and a new analysis of excess capacity for park and lend services that is limited to a single winter.

3.6.3.4 The Redwood Constraint And ISP Alternatives

Wild Goose and LGS argue that instead of retaining Los Medanos, PG&E could contract for ISP capacity or purchase an ISP facility.[972] However, as we explained in Rebuttal Testimony and our Opening Brief, there is a physical pipeline constraint on PG&E's gas transmission system (referred to as the Redwood Constraint) that limits deliveries to 2,700 MMcf/d.[973] That physical constraints prevents more than 2,700 MMcf/d from flowing into load centers like the Bay Area.[974] The Redwood Constraint is not simply something that PG&E believes exists. TURN, Wild Goose, and LGS expressly agreed in the 2019 GT&S MOU that

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970 Wild Goose and LGS Opening Brief, p. 17.

971 Wild Goose and LGS Opening Brief, p. 17.

972 Wild Goose and LGS Opening Brief, pp. 18-19.

973 PG&E-16-E, p. 7B-18, line 12 to p. 7B-20, line 19; PG&E Opening Brief, pp. 236-238.

974 PG&E-16-E, p. 7B-19, Figure 7B-1.

the Redwood Constraint was 2,700 MMcf/d.[975] In the 2019 GT&S rate case, no party disputed the existence of the Redwood Constraint and the Commission determined that it existed.[976]

Wild Goose and LGS argue that on cold days, not as much gas will be delivered to the California border from Canada, and thus the ISPs can provide more gas because there is extra, unused capacity in PG&E's transmission pipelines.[977] This reflects a misunderstanding of how the constraint works. As PG&E explained in Rebuttal Testimony:

> The Redwood Path constraint applies to almost all combinations of gas coming from the California-Oregon border and northern ISP withdrawals. Wild Goose and LGS are correct that during cold peak day events the market supplies less gas from the California-Oregon Border and thus the ISPs can provide more deliveries than identified in PG&E's updated Peak Day Supply Standard analysis (Exhibit (PG&E-3), Chapter 7, Table 7-15 of my opening testimony). However, the total still cannot be more than 2,700 mmcf/d. The Redwood Path constraint is a physical limitation that the ISPs cannot overcome simply because they want to provide more storage services.[978]

The fallacy in Wild Goose's and LGS' argument is best seen in the updated Peak Day Supply Standard, which is provided as Table 7-15 on p. 7-48 of Exhibit PG&E-03. In Table 7-15, there are two lines reflecting Northern Gas Supply (Lines 6 and 7). The gas supply available from the North, where both Wild Goose and LGS are located, includes supplies on the Redwood Path coming from Canada and other out-of-state sources and the Northern ISPs. The actual numbers delivered from these two sources may change from day to day. For example, one day supplies from outside California may be 1,800 MMcf/d while the supplies form Northern ISPs are 900 MMcf/d. The key however is that supplies from both sources (*i.e.*, outside California and the Northern ISPs) are limited to 2,700 MMcf/d as a result of the physical constraint. This is reflected in Line 8 which shows a Northern Supply limitation that is consistently 2,700 MMcf/d

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975 WGL-02, Attachment A, p. 11-Atch1-2, Section III.b ("Joint Parties agree on the following constraints: Redwood Constraint 2,700 mmcf/d").

976 D.19-09-025, p. 78 (finding that the redwood Constraint exists and that no party disputed the constraint).

977 Wild Goose and LGS Opening Brief, pp. 20-21.

978 PG&E-16-E, p. 7B-20, line 23 to p. 7B-21, line 3.

across all years. Thus, while the amount of gas from outside California and the Northern ISPs may vary between these two sources during certain periods of time, such as the winter, the constraint will always be 2,700 MMcf/d. This constraint is built into PG&E's updated Peak Day Supply Standard as indicated on Line 8 of Table 7-15.

Wild Goose and LGS argue that the Lodi facilities are located downstream of where Lines 400 and 401 begin to diverge and that they are closer to the transmission lines that serve the Bay Area than the McDonald Island and Los Medanos storage facilities.[979] There are several flaws with this argument. First, Wild Goose and LGS neglect to mention that the map they include from discovery and rely on for their argument shows "approximate locations" and is not exact, as PG&E stated in its discovery response.[980] Second, and more importantly, the fact is the Lodi facilities are not connected to PG&E transmission lines below the constraint. Whatever their proximity may be, these facilities are not connected below the Redwood Constraint.

Moreover, Wild Goose and LGS have never requested that their facilities be connected below the Redwood Constraint. The Lodi facility is owned by LGS and to interconnect it to Line 400 or another transmission line below the Redwood Constraint would require that LGS request an interconnection, something that LGS has never done.[981] This case has been pending for more than a year. If Wild Goose and LGS had believed they can offer a better solution to the capacity shortage identified by PG&E in the updated Peak Day Supply Standard, they could have easily requested an interconnection study and proposed building the necessary facilities to interconnect elsewhere on PG&E's system. Notably, they have failed to make any effort to do

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979 Wild Goose and LGS Opening Brief, pp. 21-22.

980 WGL-04, p. 67 ("See approximate locations on the map below.").

981 WGL-04, p. 5.

so. Wild Goose and LGS also ignore the challenges interconnecting storage to the local transmission system.[982]

Wild Goose and LGS claim that PG&E's representation of the Redwood Constraint in Figure 7B-1 of its rebuttal testimony is misleading because the Lodi and Kirby Storage fields "are closer to the main transmission lines that serve the Bay Area load center than Los Medanos and McDonald Island."[983] This is another red herring. Figure 7B-1 is a "representation of the existing Redwood path constraint."[984] It is not intended to be to scale nor did PG&E represent that it was to scale. Instead, it is intended to provide a clean and simple representation of the system configuration. Notably, other than allegations regarding distance and scale, Wild Goose and LGS do not assert that the system configuration represented in Figure 7B-1 is wrong.

Wild Goose and LGS argue that PG&E should be directed to study interconnecting the Lodi facilities further downstream on PG&E's transmission system as an alternative to Los Medanos.[985] There are several problems with this proposal. First, this process would likely take several years or potentially much longer. As we explained in our Opening Brief, the Los Medanos facility is needed now to address capacity shortfalls as early as 2022-2023 (and growing each year).[986] PG&E cannot delay the Los Medanos reworks required by CalGEM regulations and the replacement of obsolete equipment. Second, the only testimony offered in this proceeding directly addressing the feasibility of an interconnection study and the potential cost was offered by Mr. Graham at the hearing who explained:

> Q Okay.· If it turned out that constructing such a line would be cheaper than keeping the Los Medanos Storage Field open, would that in fact be an option that's at least worth considering?

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982 WGL-04, p. 5.

983 Wild Goose and LGS Opening Brief, p. 22.

984 PG&E-16-E, p. 7B-18, lines 24-26.

985 Wild Goose and LGS Opening Brief, p. 23-24.

986 PG&E Opening Brief, pp. 233-236, 242-243.

> A There would be a lot of additional things that PG&E would need to know besides just a cost of that line.· The capacity that is available from that facility.· Lodi Wild Goose has been extremely secretive.· We've· asked numerous data requests of those· entities to try to get at exactly how much· capacity it would have during, let's say, a late winter when their inventories are drawn down and they've refused to provide that.
>
> So it's not clear at all that building that line would actually help support the system.· The line is actually quite expensive, even though it may not be a long distance.· There is a very significant river crossing, you know, the major Delta River that crosses under the Antioch, the Carquinez bridges there go into the San Francisco Bay would need to be crossed to get between those facilities and PG&E's Antioch Terminal, or further south.· So it would take quite a bit of analysis both on PG&E's part, as well as more information from Lodi, to be able to do that analysis.

Wild Goose and LGS offer hoped for solutions that may occur at some point down the road. However, the capacity shortfall exists now and PG&E's customers who depend on reliable gas service cannot simply wait and hope that these solutions materialize.

Finally, Wild Goose and LGS propose that PG&E be directed to explore options to contract for ISP storage or acquire part or all of an ISP storage facility.[987] As PG&E explained in Rebuttal Testimony, "even if you assume that the ISP storage facilities can address the capacity shortfall, which they cannot, there is no evidence that the ISPs will offer reasonable contractual or purchase terms, especially if they know that PG&E needs the storage capacity because Los Medanos has been decommissioned or sold prematurely. The ISPs would then be in a position to dictate terms and conditions that may be very unfavorable to PG&E's customers."[988] Moreover, the retirement of Los Medanos would reduce the overall physical firm withdrawal capacity available in the PG&E service area. Independent from the disposition of Los Medanos, the purchase of ISP capacity by PG&E for operational purposes would reduce the available firm withdrawal capacity available for sale to the market. Both scenarios would increase price volatility at the Citygate and reduce the reliability of the PG&E system during extreme weather events.

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987 Wild Goose and LGS Opening Brief, p. 26.

988 PG&E-16-E, p. 7B-23, lines 6-12.

TURN also argues that PG&E should consider ISP alternatives if PG&E is concerned about a capacity shortfall.[989] However, TURN offers no separate analysis to support this argument. For the reasons stated above, TURN's proposal should be rejected.

3.6.4 Core Gas Supply Firm Storage

In our Opening Testimony, we proposed to increase the firm storage for PG&E's Core Gas Supply based on our Peak Day Supply Standard.[990] TURN proposed to reduce that amount based on its revised Peak Day Supply Standard.[991] Given the flaws in TURN's revised Peak Day Supply Standard, as explained in Section 3.6.1 above, TURN's proposal should be rejected.

TURN also recommends that the Commission make clear in "its GRC decision here that the adoption of a gas storage assignment to PG&E's Core Gas Supply function makes no assumption how the costs should be allocated among the Core and Noncore in the GT&S CARD proceeding."[992] PG&E does not oppose this recommendation.

3.6.5 Well Reworks And Retrofits – Capital (MAT 3L3)

The Reworks and Retrofits Program includes 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. This work primarily relates to retrofit/conversion of wells from their existing condition of tubing and packer to dual barrier construction consistent with CalGEM requirements and regulations but can also involve reworking a well that is impacted by activities such as pressure testing. MAT 3L3 includes the capital work associated with this conversion and inspection activity.[993] PG&E's 2023 capital expenditure forecast is $85.199 million, however, as reworks are completed, the capital

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989 TURN Amended Opening Brief, pp. 283-284.

990 PG&E-03, p. 7-55, lines 1-14.

991 TURN Amended Opening Brief, pp. 284-285.

992 TURN Amended Opening Brief, p. 286.

993 PG&E Opening Brief, p. 246.

expenditures decline significantly in 2025 and 2026. The 2026 capital expenditure forecast is $18.553 million.[994]

TURN is the only party that addresses the Reworks and Retrofits Program. TURN acknowledges that this work is required by CalGEM regulations but disputes the unit costs and the number of reworks required.[995] TURN recommends a 2023 capital expenditure forecast of $63.051 million that also declines in the later years. TURN's 2026 capital expenditure forecast is $6.869 million.[996] Below we address the unit cost and number of rework issues raised by TURN.

3.6.5.1 Unit Costs

TURN argues that PG&E's unit cost forecast should be reduced by approximately $260,000 per well from $3.298 million (PG&E's forecast) to $3.031 million (TURN's forecast).[997] In our Opening Brief, we explained in detail the flaws with TURN's proposal.[998] TURN's Opening Brief largely reiterates its testimony, but several points require a brief further response.

First, TURN argues that PG&E has approached reworks in a risk-based manner and thus "the most potentially problematic wells" should have already been addressed.[999] While it is true that PG&E used a risk-based approach in scheduling its work, the actual condition of a well and the amount of work required cannot be fully known until the rework process starts. As PG&E witness Lucy Redmond explained at the hearing in response to Judge DeAngelis' question:

ALJ DeANGELIS:·

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994 PG&E Opening Brief, p. 247, Table 3-40 (including annual capital expenditure forecasts for 2023-2026).

995 TURN Amended Opening Brief, pp. 286-287.

996 TURN Amended Opening Brief, pp. 293, 302 (TURN forecast for MAT 3L3 for 2023-2026).

997 TURN Amended Opening Brief, pp. 287-288.

998 PG&E Opening Brief, pp. 249-251.

999 TURN Amended Opening Brief, p. 288.

> Can you help me understand. Can a well be reclassified from 1 to 1A to 2 during the course of a rework program?

WITNESS REDMOND:

> Yes. It's very common that we go in with the intention of typically performing a Type 1 or a Type 1A inspection. So to differentiate for everyone here, a Type 1 is simple -- from 2019 and forward -- is simply installing a packer element and a new tubing string to meet the dual-barrier construction requirement of CalGEM.
>
> During the course of performing that inspection activity that also takes place, we could identify a defect that requires remediation in which the course of the project would change from a Type 1 to a Type 2, which would require the placement and cementing of a new inner string essentially installing a brand-new production casing in that well. In addition, you would then have to run a packer element and the tubing string to regain that dual-barrier construction requirement.
>
> Similarly, a Type 1A is installation of a new gravel pack. So if we're trying to -- the gravel pack over time needs replacement, and so for any reason, if we're looking to increase the rate on that well, we'll try to install a gravel pack -- we will install a gravel pack which will help improve performance.
>
> Similarly, as with the Type 1, in the case of a 1A, we are performing that inspection, and we identify a feature or some type of remediation that needs to take place, the Type 1A can be go to a Type 2.[1000]

While PG&E has risk-ranked its rework projects, this does not mean that lower ranked projects are less complex or will be less costly. PG&E also addressed this issue in Rebuttal Testimony explaining in detail why risk prioritization may not necessarily decrease unit costs.[1001] TURN's Opening Brief is completely silent with regard to this undisputed testimony.

Second, TURN argues, without an evidentiary support, that as PG&E gains experience the costs should come down.[1002] It is true that PG&E is gaining experience with reworks; however well work projects are not simple, routine widgets to count. Each project is an intricate and specialized program designed to maintain control of high reservoir pressures while work is conducted a mile into the earth. While familiarity with performing "typical scopes of work" is

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[1000] Tr. Vol. 6, 1000:15 to 1001:24, PG&E/Redmond.

[1001] PG&E-16-E, p. 7A-17, line 27 to p. 7A-19, line 8.

[1002] TURN Amended Opening Brief, p. 288.

acknowledged, this sentiment by TURN oversimplifies the skill and risk associated with this type of work and essentially ignores other existing factors that impact cost. As Ms. Redmond explained in Rebuttal Testimony:

> The last area related to cost is the increasing scarcity of California local vendors who provide services and materials related to the oil and gas industry, and global supply pressures related to COVID-19 and current events with the Russian invasion of Ukraine. Many California vendors have closed shop or greatly reduced their service offerings and have relocated staff to more oil and gas friendly states, especially as attention is turned to ramping up domestic supply. This is resulting in higher costs to source and procure materials and to contract with qualified vendors. <u>In fact, Wild Goose and LGS explicitly called out in their testimony that expected higher costs forecasts will materialize due to these phenomena</u>.[1003]

Thus, TURN's rhetoric about cost decreases is not only inconsistent with the evidence offered by PG&E but it is also inconsistent with the evidence offered by Wild Goose and LGS.

Finally, TURN argues that PG&E's entire rebuttal on the issue of unit costs was based on an argument regarding the use of 2018 data by TURN.[1004] Even a cursory review of PG&E's rebuttal testimony demonstrates that this assertion is simply wrong. In addition to addressing the issue of 2018 data, PG&E's rebuttal also demonstrated that: (1) permitting times (both initial and supplemental permits during well work) are increasing; and (2) costs are increasing due to scarcity. Both of these factors are pushing unit costs upward, and thus PG&E's forecast, prepared more than a year ago, is likely conservative. Moreover, at the hearing Ms. Redmond explained well types can readily change during the rework process which will result in substantially higher costs.[1005] If anything, given this undisputed evidence, PG&E's unit cost forecast (which is based largely on vendor quotes from 2021) likely understates the actual costs that will be incurred during the 2023-2026 time frame.[1006]

1003 PG&E-16-E, p. 7A-17, lines 17-26 (footnote omitted) (emphasis added).

1004 TURN Amended Opening Brief, pp. 289-290.

1005 Tr. Vol. 6, 1000:15 to 1001:24, PG&E/Redmond.

1006 PG&E-03, WP 7-30 to WP 7-32 (cost calculation for rework types).

3.6.5.2 Number Of Well Reworks And Retrofits

TURN's Opening Brief largely repeated arguments from testimony.[1007] We addressed these arguments in our Opening Brief.[1008] Notably, TURN does not dispute Ms. Redmond's detailed explanation in Rebuttal Testimony as to why PG&E is forecasting additional emergent work as a result of CalGEM testing requirements. Instead, TURN simply says that PG&E, the Commission, and stakeholders should discuss this matter further with CalGEM.[1009] PG&E welcomes these discussions and TURN's participation. However, until the regulations are changed, PG&E's undisputed evidence concerning the forecasted amount of emergent work is more than sufficient support for our forecast of the number of wells that will need to be reworked during the rate case period. The Commission should adopt a forecast based on the facts, not TURN's "hope" that regulations will change in the future. And, as TURN notes, if the regulations do change in the future and the number of emergent wells decrease, customers will be refunded any overcollection through the Gas Storage Balancing Account (GSBA).[1010]

3.6.6 Well Reworks And Retrofits – Expense (MAT AH2)

The Reworks and Retrofits Program is an expense program that includes the scope of work to perform reinspections of wells following conversion to tubing and packer as required by CalGEM's regulations. In addition, this program includes work to address any integrity issues identified as emergent that require a rig mobilization (*i.e.*, response to a failed pressure test).[1011] PG&E's 2023 forecast for this program is 3.207 million, but the forecasts for 2025 and 2026 increase substantially based on reinspection compliance deadlines. The forecast for 2025 is $5.040 million and the forecast for 2026 is $24.056 million.[1012]

1007 TURN Amended Opening Brief, pp. 290-292.

1008 PG&E Opening Brief, pp. 247-249.

1009 TURN Amended Opening Brief, p. 292.

1010 TURN Amended Opening Brief, p. 292.

1011 PG&E Opening Brief, p. 253.

1012 PG&E Opening Brief, p. 254, Table 3-43.

TURN is the only party that addresses this program and recommends eliminating the forecast for 2023-2025 and reducing the 2026 forecast to $5.410 million.[1013] TURN does not dispute PG&E's forecasted unit costs, instead it disputes the number of reinspections that will be required.

First, TURN argues that ten (10) reinspections associated with emergent work resulting from CalGEM requirements should be eliminated. As with retrofits described above in Section 3.6.5.2, TURN's proposed reduction is based on its hope that the CalGEM regulations will change.[1014] TURN does not dispute PG&E's testimony that, based on current CalGEM regulations, PG&E's forecast of emergent work is entirely reasonable.[1015]

Second, TURN argues that eleven (11) reworks may not be required by PHMSA and CalGEM regulations.[1016] We addressed this argument in our Opening Brief and demonstrated that TURN's reading of the PHMSA and CalGEM regulations was mistaken.[1017] We also explained that our forecast, which assumed reinspections every 7 years, was conservative compared to the current CalGEM requirement of reinspections every 2 years.[1018]

TURN does not and cannot dispute that current CalGEM regulations require reinspections every two years. Instead, TURN's once again hangs its hat on the "hope" that CalGEM will modify its regulations in response to a pending PG&E petition.[1019] However, as TURN acknowledges the CalGEM regulations have not changed yet and as Ms. Redmond explained in Rebuttal Testimony, CalGEM is currently requiring SoCalGas to perform

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1013 TURN Amended Opening Brief, p. 299.

1014 TURN Amended Opening Brief, p. 294.

1015 PG&E Opening Brief, pp. 254-255.

1016 TURN Amended Opening Brief, pp. 294-296.

1017 PG&E Opening Brief, pp. 255-257.

1018 PG&E Opening Brief, p. 255-256.

1019 TURN Amended Opening Brief, pp. 296-298.

reinspections every 2 years, except for a small population of brand-new wells.[1020] TURN's proposal to essentially eliminate any funding for the reinspection program based on TURN's hoped for regulatory changes is unreasonable and imprudent. Notably, PG&E's 7-year reinspection forecast is completely consistent with statements by Wild Goose and LGS that they expect to perform reinspections every 7 years.[1021]

3.6.7 Well Integrity Assessments – Expense (MAT AH1)

The Integrity Inspections and Surveys Program covers the scope of work to perform integrity inspection and surveys on storage wells including: (1) annual and periodic compliance surveys; (2) thru-tubing barrier inspection surveys; and (3) direct well integrity and production casing/barrier inspections and tests. 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.

TURN is the only party that addresses well integrity assessments and proposes a reduced 2023 forecast of $7.290 million, which declines in the late years of the rate case (2025-2026).[1022] TURN's proposed reduction is based on the number of wells required. TURN argues that fewer wells are needed and thus fewer assessments required based on its revised Peak Day Supply Standard.[1023] The flaws with TURN's proposed Peak Day Supply Standard revisions are addressed above in Section 3.6.1.

3.6.8 New Well Storage Drilling – Capital (MAT 3L1)

Drilling new wells at existing storage facilities is critical to ensure that the natural gas can be injected into or withdrawn from storage facilities when needed. New wells are especially critical because CalGEM regulations regarding retrofits and re-works, as well as more frequent

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1020 PG&E-16-E, p. 7A-26, lines 6-9.

1021 PG&E-35, Wild Goose and LGS response to PG&E_JointLW004, Question 2.

1022 TURN Amended Opening Brief, pp. 299-300.

1023 TURN Amended Opening Brief, pp. 299-300.

inspection cycles, can result in existing wells being taken out of service frequently and for extended periods of time. In addition, the tubing and packer configuration required by CalGEM regulations reduces well capacity.[1024] Finally, as well inspection projects are performed more frequently under CalGEM regulations, well obsolescence continues to increase as more wells are subject to mechanical damage during downhole well projects and will necessitate permanent abandonment to mitigate damage. PG&E has seen this phenomenon play out in the past several years during increased inspections and expects this trend will continue. To ensure gas transmission system reliability given these regulatory impacts, PG&E is proposing to drill 12 new wells with capital costs of $18.886 million in 2023, $45.884 million in 2024, and $32.973 million in 2025.[1025] We addressed in detail in our Opening Brief the need for new wells.[1026]

In its Opening Brief, TURN addresses this issue in a single paragraph relying on its flawed analysis of the Peak Day Supply Standard.[1027] TURN proposes no new well drilling during the rate case period (2023-2026) despite the significant impact on storage field availability as a result of CalGEM and PHMSA regulations. TURN simply ignores this evidence.

3.6.9 Well Controls And Continuous Monitoring – Capital (MAT 3L5)

The scope of this program is to install safety-related equipment to monitor pressure and gas flow at PG&E's storage fields. Projects in this program include installation or replacement of equipment to: (1) monitor injection flow at McDonald Island; (2) monitor annular pressure at all storage fields; and (3) replace older monitoring equipment at McDonald Island. In addition, this

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1024 PG&E Opening Brief, pp. 243-244.

1025 PG&E Opening Brief, p. 244, Table 3-39.

1026 PG&E Opening Brief, pp. 243-246.

1027 TURN Amended Opening Brief, p. 300.

program includes necessary controls upgrades at the Los Medanos facility.[1028] PG&E's capital forecast for this project is $1.365 million in 2023 and $7.525 million in 2024.

TURN is the only party that addresses this program and proposes completely eliminating the 2024 capital forecast.[1029] TURN's argument is based on its assertion that Los Medanos should not be retained, which we addressed in our Opening Brief[1030] and above in Sections 3.6.1 through 3.6.3.

3.7 Gas Operations And Maintenance[1031]

Operations and maintenance (O&M) activities cover both Gas Distribution and Gas Transmission and Storage assets. Maintenance of gas facilities is an integral component to managing threats and the O&M programs are foundational to enable the Asset Family Owners to identify and mitigate threats on the gas system. The requested expenditures will help mitigate safety and reliability risks related to delivering gas through approximately 43,400 miles of gas main, nearly 3.6 million gas service connections, and approximately 6,600 miles of transmission pipeline. In this section of our Reply Brief, we address issues regarding our O&M program forecasts raised by parties in their Opening Briefs:

TABLE 3-7
O&M PROGRAM DISPUTED ISSUES

Section	Disputed Program	Party
3.7.1	Locate and Mark	TURN, Cal Advocates
3.7.2	Standby Governance	TURN
3.7.3	Meter Protection Program	TURN, Cal Advocates
3.7.4	Relocation of Meter Sets	TURN

1028 PG&E Opening Brief, p. 251.

1029 TURN Amended Opening Brief, pp. 301-302.

1030 PG&E Opening Brief, pp. 232-243.

1031 Gas Operations and Maintenance is addressed in Chapter 8 of PG&E's Prepared Testimony, PG&E-03, and further addressed in Chapter 8 of PG&E's Rebuttal Testimony, PG&E-16-E.

3.7.1 Locate And Mark – Expense (MAT DFA)

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. Excavators must contact 811 prior to proposed excavation, generating a notification (USA ticket). USA tickets are transmitted electronically to PG&E to respond to or "work," including locating and field marking all subsurface installations identified within the area of proposed excavation, providing records of the locations of the subsurface installations, or advising the excavator PG&E operates no facilities within their proposed area of excavation.[1032]

PG&E forecasts $77.6 million of expense in 2023 for the GD portion of the Locate and Mark program. TURN proposes a 2023 GD Locate and Mark MAT DFA forecast of $74.1 million, which results in an expense reduction of $3.5 million. Cal Advocates recommends a 2023 forecast of $36.9 million for GD Locate and Mark MAT DFA, which is $40.7 million lower than PG&E's request. PG&E addresses the Opening Brief arguments of TURN[1033] and Cal Advocates[1034] below.

3.7.1.1 PG&E's Forecast Of 12 Percent Growth In DFA Tickets Is Reasonable

As explained in PG&E's Opening Brief,[1035] PG&E's 2023 unit forecast is based on the number of Locate and Mark USA tickets worked in 2019 split between GD and GT, with a 12 percent year over year escalation applied. PG&E uses the 12 percent increase seen in ticket volume between 2018 and 2019,[1036] the most recent full year of tickets worked that was not impacted by work stoppages caused by the COVID-19 pandemic.[1037] The 12 percent growth

1032 PG&E Opening Brief p. 262.

1033 TURN Amended Opening Brief, pp. 303-308, Section 3.7.1.

1034 CAL Advocates Opening Brief, pp. 72-75, Section 3.7.1.

1035 PG&E Opening Brief pp. 264-266, Section 3.7.1.1.

1036 PG&E-16-E, p. 8-11, lines 2-5.

1037 PG&E-16-E, PG&E's response to Data Request TURN_049-Q01Rev01(d.ii), dated 4/1/22, p. AppA-342.

rate also 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.[1038] Even though the expected growth in tickets has not materialized yet, PG&E expects to see an increase in tickets by 2023 as a result of the Excavation Board continuing to develop its oversight.[1039]

TURN argues that PG&E should have used the 10% growth rate increase seen between 2016-2019 as the basis for its forecast.[1040] In its Opening Brief, PG&E explained that TURN's 4-year average does not represent the most recent pre-COVID growth rate use seen from 2018 to 2019, and therefore understates likely growth in tickets.[1041] PG&E's use of the 2018-2019 growth rate is not "cherry picking" as TURN alleges.[1042]

TURN also claims that PG&E provides no evidence that the outreach efforts of the Excavation Board will result in a significant increase in tickets.[1043] As PG&E explained in its Opening Brief, TURN incorrectly attributes PG&E's 12 percent forecast ticket volume increase to Area of Continuous Excavation (ACE) tickets alone.[1044] While the new regulations include implementing the use of ACE tickets, they also include investigation and enforcement by the Excavation Board of all excavators, not just in ACE areas. PG&E expects this will increase

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1038 PG&E-16-E, p. 8-11, lines 5-11.

1039 PG&E-16-E, p, 8-13, lines 9-20.

1040 TURN Amended Opening Brief, p. 304.

1041 PG&E Opening Brief, p. 265.

1042 TURN Amended Opening Brief, p. 306.

1043 TURN Amended Opening Brief, p. 306.

1044 TURN calculated that ACE tickets amounted to five-thousandths of one percent of the tickets PG&E worked in 2021. [TURN-06, p. 31, lines 6-7.] TURN calculates this percentage by dividing the number of onsite meetings performed for ACE tickets completed between July 2020 and December 31, 2021 (34), by PG&E's 2021 ticket forecast (723,318). This calculation is incorrect because it compares actual work performed to a forecast and uses only the portion of Locate and Mark tickets that resulted in onsite meetings, which does not reflect the total number of Locate and Mark tickets worked. PG&E-16-E, p. 8-13, fn. 12.

ticket volumes not only in ACE areas, but more generally as well.[1045] Thus the relatively small numbers of recorded ACE tickets in 2020 and 2021 cited by TURN[1046] do not provide any indication of the overall growth of tickets expected when the Excavation Board fully implements its oversight program. This is especially true since the California Dig Safe Board 2020 Results Report states that planned in-person events targeting outreach to these groups, were hampered by the COVID-19 pandemic.[1047]

PG&E responded in its Opening Brief[1048] to Cal Advocates' recommendation to use a five percent year-over-year increase in tickets worked, based on the average annual increase in tickets worked from 2016-2020.[1049] Cal Advocates argues that the 2018-2019 period relied on my PG&E for its 12% growth rate represents an outlier when compared to recorded tickets from 2016-2020.[1050] As explained in PG&E's Opening Brief, however, Cal Advocates' 6-year average includes data from almost 7 years ago (2016) that is not representative of today's conditions and also includes the non-typical year of 2020 that was affected by COVID-19.[1051] It also fails to take into account the aggressive and escalating outreach to excavators being implemented by the Excavation Board as discussed above. In its Opening Brief, Cal Advocates argues that PG&E should have already realized an increase in annual tickets because PG&E fully implemented the Dig Safe Board's regulations by July 1, 2020.[1052] However, as explained

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1045 PG&E-16-E, p. 8-13, line 21 to p. 8-14, line 2.

1046 TURN Amended Opening Brief, p. 305.

1047 This information is publicly available on the California Underground Facilities Safe Excavation Board website. PG&E-16-E, PG&E provided a link in PG&E's response to Data Request Cal Advocates_181-Q06(b), dated 12/21/21, pp. AppA-345 to AppA-346.

1048 PG&E Opening Brief, pp. 265-266.

1049 CALPA-02, p. 41, lines 23-24.

1050 Cal Advocates Opening Brief, p. 74.

1051 Even TURN acknowledges that the number of tickets worked in 2020 dropped due to COVID-19 issues. See TURN-06, p. 30, lines 16-20.

1052 Cal Advocates Opening Brief, p. 73.

above, 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.

For all these reasons the Commission should adopt PG&E's 2023 Locate and Mark ticket forecast and find that PG&E's 12 percent growth rate is reasonable.

3.7.1.2 PG&E's Unit Cost Is Reasonable

In its Opening Brief, PG&E demonstrates why its proposed unit cost of $86 per Locate and Mark ticket is reasonable, and why Cal Advocates' proposed $49 unit cost is not reasonable.[1053] In summary, Cal Advocates' unit cost is too low because it (1) used 2020 that did not represent normal operating conditions as it was impacted by work stoppages caused by the COVID-19 pandemic; (2) excluded shareholder funded costs from the unit cost calculation that will become part of base ratepayer expenses in 2023. Cal Advocates did not address the unit cost issue in its Opening Brief.

3.7.2 Standby Governance – Expense (MAT DFB)

In the standby process, a PG&E field employee monitors excavation activity on both GD and GT assets in a watch and protect capacity to prevent damage to PG&E's critical facilities. PG&E's 2023 forecast for GD Standby Governance is $0.5 million and for GT Standby Governance is $7.5 million.[1054] TURN proposes a 2023 expense forecast for GD Standby Governance of $0.4 million as compared to PG&E's expense forecast of $0.5 million, which results in an expense reduction of approximately $9 thousand dollars,[1055] and a 2023 GT Standby Governance forecast of $5.3 million, which is $2.1 million lower than PG&E's forecast

1053 PG&E Opening Brief, pp. 266-267, Section 3.7.1.2.

1054 PG&E-16-E, p. 8-18, lines 18-20.

1055 PG&E-16-E, p. 8-19, lines 16-20.

of $7.5 million.[1056] PG&E addresses TURN's arguments[1057] in its Opening Brief[1058] and below.

3.7.2.1 PG&E's GD Standby Governance Forecast Is Reasonable

PG&E's forecasted increase in Locate and Mark tickets worked (see Section 3.6.1 above) 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).[1059] TURN's recommendation to reduce the DFB forecast is based on assuming a 10 percent growth in tickets, compared to PG&E's 12 percent assumption. PG&E explains why its 12 percent growth rate for both Locate and Mark and Standbys is reasonable in its Opening Brief and in Section 3.7.1 of this Reply Brief. The Commission should therefore adopt PG&E's 2023 forecast for GD Standby Governance of $0.5 million without any reduction.

3.7.2.2 PG&E's GT Standby Governance Forecast Is Reasonable

Both TURN and PG&E use recorded 2019 numbers as the baseline for their GT DFB forecasts. However, TURN uses this figure for 2023 without escalation, while PG&E uses the same 12 percent annual escalation rate applicable to Locate and Mark because PG&E expects the need for standby activities will continue to increase in direct correlation with the increase in Locate and Mark tickets worked.[1060] TURN claims that 12 percent growth is not justified because "units fluctuated in 2015-2018 and then declined dramatically in 2019."[1061] However, since 2019, standby units have trended higher, and PG&E expects the need for standby activities will continue to increase in direct correlation with the increase in Locate and Mark tickets

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1056 PG&E-16-E, p. 8-20, lines 20-23.

1057 TURN Amended Opening Brief, pp. 303-308, Section 3.7.1.

1058 PG&E Opening Brief, pp. 269-270, Section 3.7.2.2.

1059 PG&E-16-E, p. 8-20, lines 3-16.

1060 *Id*.

1061 TURN Amended Opening Brief, p. 307.

worked.[1062] In 2020, for example, recorded tickets increased to 5,774 (an 11 percent increase from 2019).[1063] TURN also argues "continuing work of the Standby Governance Team justifies using the 2019 recorded units (5,221) as the basis for the 2023 forecast."[1064] Damage prevention activities do not remain static, however.[1065] Despite implementation of new processes and procedures that reduced standbys and made the group more efficient and effective, PG&E forecasts an increase in Locate and Mark tickets, and as industry recommendations evolve, it is expected that the need to perform standbys will also increase.[1066]

3.7.3 Meter Protection Program (MAT EXB)

The purpose of the Meter Protection Program (MPP) is to protect meters and risers that are vulnerable to vehicular damage, by installing steel posts, and to install service valves where existing service valves are inaccessible.[1067] Inadequate meter protection is noted when PG&E field personnel visit a meter set, whether as part of a survey or for other reasons. PG&E's 2023 expense forecast for the MPP is $35.4 million, for 43,193 meter protection locations, at a unit cost of $821.[1068] TURN recommends reducing the forecast by $11.8 million by slowing the pace of remediation.[1069] Cal Advocate recommends a $22.8 million reduction in the forecast

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1062 PG&E Opening Brief, pp. 269-270.

1063 PG&E-16-E, p. 8-21, lines 6-10.

1064 TURN Amended Opening Brief, p. 307.

1065 PG&E Opening Brief, p. 270.

1066 PG&E-16-E, p. 8-21, line 20-27.

1067 PG&E Opening Brief, p. 270.

1068 PG&E-3-ES, WP 8-21, line 3.

1069 PG&E Opening Brief, p. 272. TURN also recommends the Commission require PG&E provide an RSE for Meter Protection for the Loss of Containment on Gas Customer Connected Equipment (CCE) risk for the next GRC. This recommendation is addressed in Section 3.2.2.4 of PG&E's Opening brief.

reflecting a unit reduction to 15,421 meter protection locations in 2023 in contrast to PG&E's request of 43,193 locations.[1070]

PG&E addresses TURN's arguments[1071] and Cal Advocates' arguments[1072] in its Opening Brief[1073] and below.

3.7.3.1 The Commission Should Not Delay The Remediation Of The Existing Backlog Of MPP Units

TURN does not take issue with PG&E's forecast of EXB MPP units, or PG&E's unit cost. TURN's reduction is based on remediating PG&E's forecast of 81,133 backlogged/pending units at the beginning of this GRC rate case period over 20 years, and not over 5 years as proposed by PG&E.[1074] PG&E addresses TURN's proposal to extend remediation of the backlog in its Opening Brief.[1075] In summary: (1) low RSE scores for this program do not justify slowing the pace of remediating unsafe meter installations and allowing the back log to grow; (2) the pace of the 1990 meter protection program should not be used as a benchmark for remediating the current back log; and (3) notwithstanding the ongoing Long-Term Planning Rulemaking, the Commission should adopt PG&E's approach for the continued compliance with federal regulations regarding meter protection.

In its Opening Brief, TURN further claims that "PG&E has been unable to remediate all locations within two years. PG&E stretched the goal to five years in its 2020 GRC forecast."[1076] However, this is due the fact that as part of the 2020 GRC settlement, PG&E's original forecast

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1070 PG&E Opening Brief, p. 272; CALPA-02, p. 45, lines 5-6.

1071 TURN Amended Opening Brief, pp. 308-311, Section 3.7.2.

1072 Cal Advocates Opening Brief, pp. 75-82, Section 3.7.2.

1073 PG&E Opening Brief, pp. 270-272, Section 3.7.3.

1074 TURN Amended Opening Brief, p. 309.

1075 PG&E Opening Brief, pp. 272-274, Section 3.7.3.1.

1076 TURN Amended Opening Brief, p. 309.

$13.238 million was reduced to $8.238 million.[1077] The lower forecast did not allow PG&E to address as many meters as it originally proposed and has allowed the backlog to grow. If PG&E's 2023 forecast is cut as TURN proposes, the backlog of unprotected meters will simply continue and even grow in the future.

3.7.3.2 PG&E's 2023 Forecast Of MPP Units Is Reasonable

PG&E's 2023 forecast of 43,193 meter protection locations consists of 4 separate forecasts:[1078] (1) 3,410 locations with difficult access (known as Can't Get In, or CGI locations) based on an eight percent CGI rate seen from work performed by PG&E's contractor in 2020;[1079] (2) 19,380 "New Finds" based on expected new Abnormal Operating Conditions of "AOC" locations identified through routine Leak Survey and Atmospheric Corrosion (AC) inspection plans along with field services activities; (3) 20,283 Existing Locations (or AOC backlog as it is also referred to) based on total pending meter protection locations (81,133) divided by the four-year 2023 rate case period;[1080] and (4) 120 Customer Call-ins.

Cal Advocates takes issue with the 43,193 unit forecast and proposes 15,421 meters instead.[1081] Cal Advocates argues that PG&E's forecasts for CGI units, New Finds, Exist Units (backlog units); and Customer Call Ins are all too high and unsupported.[1082] PG&E has

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1077 2020 GRC Settlement adopted in the final GRC decision, D.20-12-005, pp. 4-5. Section 2.2.5, reducing PG&E's forecast $13.238 million to $8.238 million.

1078 PG&E Opening Brief, p. 270-271.

1079 PG&E-3-ES, WP 8-21, lines 25 and 28.

1080 PG&E-16-E, PG&E's response to Data Request CalAdvocates_183-Q02Supp01(c), dated 1/10/22, pp. AppA-348 to AppA-349.

1081 Cal Advocates Opening Brief, p. 76.

1082 Cal Advocates Opening Brief, pp. 77-79, Section 3.7.2.1 (Existing Units/Backlog); pp. 79-80, Section 3.7.2.2 (New Finds); p. 81, Section 3.7.2.3 (Customer Call Ins); and pp. 81-82, Section 3.7.2.4 (CGIs).

addressed Cal Advocates arguments in detail in its Opening Brief.[1083] In summary, Cal Advocates' unit forecasts are understated because: (1) for CGI's, PG&E's approach of using historic find data (and not completion data relied on by Cal Advocates) is the correct approach to forecast a 2023 CGI population that will allow the backlog of these types of meter protection to be effectively addressed going forward; (2) the total number of New Finds is increasing in comparison to prior years primarily because the frequency of leak survey inspections, where meter protection locations are identified, has increased; (3) Cal Advocates' New Find methodology relies on actual meter protection units mitigated in 2021 and not on a forecasted find rate, ignoring the fact that PG&E is forecasting to try and address a larger number of MPP units in 2023, and not simply repair at historic rates; (4) Cal Advocates' Existing Location (backlog) calculation is wrong because it fails to include the largest contributor to the existing Meter Back log: meters found through leak survey inspections; (5) Cal Advocates' backlog remediation pace of five years instead of PG&E's four-year forecast pace, will only contribute to further increasing a backlog of work as additional locations are found and added to the meter protection program scope; and (5) Cal Advocates ignores Customer Call In locations in its forecast.

In its Opening Brief, with respect to the Existing Unit/Backlog forecast, Cal Advocates claims that PG&E did not explain the 51,934 meter locations that it included to arrive at the 81,133 total Existing Unit back log needing remediation in the 2023-2026 period.[1084] However, PG&E has clearly explained the basis for the 51,934 locations. Cal Advocates' forecast methodology uses the Existing (backlog) Locations in PG&E's database (33,814) as of June 2020 and adds only the meters found in the field in 2021. However, MPP meters are discovered not just in the field, but continuously through various means including leak survey inspections.

1083 PG&E Opening Brief, p. 274, Section 3.7.3.2 (CGIs); p. 275, Section 3.7.3.3 (New Finds); pp. 276-277, Section 3.7.3.4 (Existing Units/Backlog); and p. 277, Section 3.7.3.5 (Customer Call Ins).

1084 Cal Advocates Opening Brief, p. 78.

Meters needing protection found through leak survey inspections in 2021 number 51,934 through November 22, 2021 as provided to Cal Advocates in a discovery response.[1085] These unremedied meter protection locations found in the 2021 survey were excluded in Cal Advocates' calculations for the backlog forecast. These units will need to be addressed along with the 33,814 units that were in the backlog before 2021.

For all these reasons, the Commission should adopt PG&E's unit forecast of 43,193 meter protection units in 2023 and reject Cal Advocates' understated forecast of 15,421 meters.

3.7.4 Relocation Of Meter Sets – Capital (MAT 27A)

The purpose of the Relocation of Meter Sets Program is two-fold: (1) meter protection through the re-location of the meter set;[1086] and (2) relocating the meter set due to an inaccessible service valve.[1087] PG&E forecasts 250 capital units to be completed in 2023 at cost of $7.2 million.[1088] TURN is the only party that addresses this program in its testimony and forecasts 184 units in 2023 reducing PG&Es' forecast by $1.9 million. TURN's forecast is the result of slowing the pace of the capital meter protection program (MAT 27A) to match its recommendation for slowing the pace of the expense meter protection program (MAT EXB). As explained in PG&E's Opening Brief, TURN's proposal should not be adopted.[1089] Delaying expense (EXB) or capital (27A) meter protection work beyond PG&E's forecast timeframe of 2026 is unreasonable as explained in Section 3.7.3.1 above. By performing the necessary meter protection work, customers' gas meters can be protected from the risk of vehicular damage and

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1085 PG&E-16-E, PG&E's response to Data Request Cal Advocates_183-Q02Supp01, dated 1/10/22, pp. AppA-347 to AppA-353. The 51,934 total appears in the table at the top of p. AppA-353.

1086 The type of work performed to remediate a Meter Protection location dictates whether it is capital (MAT 27A) or expense (MAT EXB). PG&E-16-E, p. 8-37, lines 25-27.

1087 PG&E-03, p. 8-36, lines 1-4.

1088 PG&E's derivation of the 250 units is set forth at PG&E-16-E, p. 8-36, line 5 to p, 8-37, line 3.

1089 PG&E Opening Brief, p. 278-279, Section 3.7.4.

the potential for gas release. Extending the pace means the meter protection risk will remain unaddressed for a longer period of time.

3.8 Gas Operations Corrosion Control[1090]

PG&E's Corrosion Control Program capital and expense forecasts are designed to mitigate the threats of corrosion to PG&E's gas distribution (excluding customer meter sets), transmission, and storage assets. These forecasts are based on PG&E's risk assessment of these threats; and PG&E's plan to reduce these risks. In this section of our Reply Brief, we address issues regarding our Corrosion Control program forecasts raised by parties in their Opening Briefs:

TABLE 3-8
CORROSION CONTROL DISPUTED ISSUES

Section	Disputed Program	Party
3.8.1	GD Atmospheric Corrosion Mitigation – Mains	Cal Advocates
3.8.2	GD Atmospheric Corrosion Mitigation – Services	Cal Advocates
3.8.3	GD Capital Corrosion Control	Cal Advocates
3.8.4	GT&S Corrosion Control Capital Expenditures	Cal Advocates

Cal Advocates' proposal to continue the Internal Corrosion Balancing Account (ICBA) is addressed in Section 3.14.3.3 of this Reply Brief.

3.8.1 GD Atmospheric Corrosion Mitigation – Mains (MAT FHL)

This program mitigates deficient coating systems identified during atmospheric corrosion inspections of steel distribution main spans.[1091] Typical mitigation projects include coating repair or coating replacement.[1092] PG&E is forecasting to spend $3.2 million in 2023 to

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1090 Gas Operations Corrosion Control is addressed in Chapter 9 of PG&E's Prepared Testimony, PG&E-03, and further addressed in Chapter 9 of PG&E's Rebuttal Testimony, PG&E-16-E.

1091 PG&E Opening Brief, p. 281.

1092 PG&E-03, p. 9-27, lines 1-18.

mitigate 145 GD Main spans that were identified during 2020 atmospheric corrosion inspections, an increase of approximately $2.7 million compared to 2020 recorded costs[1093] and an increase of 117 spans compared to 2020 recorded units.[1094] 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 Inspection Project (MAT FHK).[1095] Cal Advocates is the only party that addresses this program and proposes $1.2 million (a $2.0 million reduction) in the forecast claiming that PG&E did not support the significant increase in the number of main mitigation projects in 2023 due to an increase in the number of spans discovered in 2020,"[1096] and recommending a revised unit cost of $11,231 based on 2021 partial year data, compared to PG&E's $21,961 unit cost, which was based on the 2018-2020 average.[1097]

In its Opening Brief,[1098] PG&E addressed Cal Advocates' arguments.[1099] In summary, Cal Advocates' forecast of 108 mitigation projects in 2023 is too low because:[1100] (1) Cal Advocates' recommended 2023 main mitigation rate incorrectly assumes that atmospheric corrosion inspections and remediations are conducted in the same year.[1101] The vast majority of PG&E's atmospheric corrosion remediation projects occur, however, in the third year following the atmospheric corrosion inspections (i.e., 2023 span remediation projects were

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1093 PG&E-03, p. 9-27, lines 14-18.

1094 A.18-12-009, PG&E GD Pipeline Safety Report No. 2020, p. 28, Table 7-1, line 51.

1095 PG&E-03, WP 9-48.

1096 CALPA-02, p. 58, lines 16-18.

1097 CALPA-02, p. 60, lines 2-4. PG&E cannot duplicate the calculation utilized by Cal Advocates to provide $1.209 million (108 x $11,231 ≠ $1.209 million).

1098 PG&E Opening Brief, pp. 281-284, Section 3.8.1.

1099 Cal Advocates Opening Brief, pp. 86-90, Section 3.8.1.2.

1100 PG&E Opening Brief, p. 282-284.

1101 PG&E Opening Brief, p. 282.

identified during 2020 span inspections)[1102]; (2) Cal Advocates acknowledges that PG&E identified an additional 532 spans following a records research project[1103] but does not consider the impact of this effort in its unit forecast.[1104] The increase in 2023 GD Main Atmospheric Corrosion Mitigation, MAT FHL, is due to the number of newly-identified spans;[1105] and (3) Cal Advocates relies on 2021 recorded data that was not available when PG&E submitted its 2023 GRC.[1106]

With regard to unit costs, PG&E's 2023 unit cost forecast of $21,961 is based on the average unit cost for this work stream for the period 2018-2020, escalated to 2023 while Cal Advocates recommends utilization of a calculated partial-year 2021 unit cost ($11,231) without escalation for 2023.[1107] Cal Advocates' unit cost is significantly lower (~55 percent) than the average of 2018-2020 unit cost adjusted to 2021 dollars and should be rejected.[1108]

In its Opening Brief, Cal Advocates makes the following additional arguments.

First, Cal Advocates derived their recommended 2023 mitigation rate (15 percent) by dividing the number of 2021 main span mitigations (78) by the of 2021 main span inspections (519) .[1109] Cal Advocates appears to acknowledge that its mitigation rate incorrectly assumes that atmospheric corrosion inspections and remediations are conducted in the same year and correctly re-calculates the 2021 mitigation rate at 43%.[1110] If this corrected rate were applied to

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1102 PG&E-16-E, p. 9-10, lines 15-23.

1103 CALPA-02, p. 58, lines 13-15.

1104 PG&E Opening Brief, p. 283.

1105 PG&E-16-E, p. 9-11, lines 5-12.

1106 PG&E-16-E, p. 9-11, lines 13-17; PG&E Opening Brief, p. 283.

1107 CALPA-02, p. 59, lines 22-26.

1108 PG&E-03, WP 9-16, line 10 provides a 2021 unit cost of $20,562.79. ($11,231 / $20,562.79 = ~0.55).

1109 CALPA-02, p. 59, Table 2-45.

1110 Cal Advocates Opening Brief, p. 89.

PG&E's forecast of 2023 inspections, the forecast remediation units would exceed PG&E's forecast. However, without explanation or justification Cal Advocates then rejects the corrected 2021 mitigation rate of 43% mitigation rate because it is "much larger than the rate of 18% derived by comparing 2018 inspections (435 inspections) with 2021 mitigation projects (78 mitigations).[1111] Given the acknowledgment in Cal Advocates' Opening Brief that the corrected mitigation rate of 43% is significantly higher than the 15% rate used in Cal Advocates' recommended 2023 forecast of 108 spans, the Commission should reject Cal Advocates' recommendation, and instead adopt PG&E's 2023 forecast of 145 spans requiring remediation.

Second, with respect to PG&E's unit cost forecast of $21,961 which is based on the 2018-2020 average unit cost for this work stream, escalated to 2023, Cal Advocates claims "PG&E's 2023-unit cost should be ignored because it cherry picks recorded data to arrive at the highest unit cost for its forecast."[1112] The basis for this claim is "because the 2018-unit cost for this year is 52% higher than the 2021-unit cost." This criticism is unwarranted. First, 2021 data was not available to PG&E at the time it prepared its forecast. Second, use of 2021 recorded data violates the Commission's rate case plan, and should be rejected. The use of 2021 recorded data in this GRC is further discussed in Section 1.5 of PG&E's Opening Brief. PG&E's use of the 2018-2020 average is sound forecasting practice and comports with the rate case plan. The Commission should adopt PG&E's $21,961 forecast.

3.8.2 GD Atmospheric Corrosion Mitigation – Services (MAT FHM)

GD Atmospheric Corrosion Mitigation - Services mitigates 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 is forecasting $1.6 million in 2023 to mitigate 1,822 standard historic units (coating

1111 Cal Advocates Opening Brief, p. 89.

1112 Cal Advocates Opening Brief, p. 89.

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.[1113]

Cal Advocates recommends $3.924 million for MAT FHM, which is $8.348 million less than PG&E's request claiming that PG&E has not met its burden of proof for service riser units.[1114] Cal Advocates calculated its 3.924 million forecast by adjusting PG&E's November 30, 2021-recorded expense amount of $3.597 million to include an estimate of December expenses ($327,000 = 1/11th of $3.597 million) for the repair of 24,366 units.

In its Opening Brief, PG&E responded to Cal Advocates forecast and arguments, demonstrating that PG&E's forecast is reasonable.[1115] First, since PG&E did not implement the expansion of service riser remediation requirements[1116] 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.[1117] Second, PG&E used an engineering estimate that 5 percent of future inspections would result in service risers requiring remediation under the new requirements. This was entirely appropriate since the 2021 data that Cal Advocates relies on was not available when PG&E prepared its forecast, and in any event 2021 data is not representative of the future rate of riser repair.[1118] Finally, Cal Advocates'

1113 PG&E Opening Brief, p. 284, and fn. 1198: "In 2017, PG&E standardized the atmospheric corrosion inspection of main and service spans including a more rigorous inspection of the soil to air transition zone per 49 CFR 192, Subpart I requirements, along with a requirement to mitigate any wrap damage in that zone. In 2021, the inspection of soil to air transitions at service risers became more rigorous, and the subsequent repair of wrap damage was expanded to include said risers. PG&E-03, p. 9-28, lines 12-19."

1114 Cal Advocates Opening Brief, p. 84.

1115 PG&E Opening Brief, pp. 284-286, Section 3.8.2.

1116 PG&E-16-E, p. 9-13, lines 3-7.

1117 PG&E Opening Brief, p. 285.

1118 PG&E Opening Brief, p. 285-286.

recommendation to adopt the 2021 adjusted recorded expense amount of $3.9 million for 2023 does not provide for standard annual cost escalation.[1119]

In its Opening Brief, Cal Advocates states “Cal Advocates does not dispute that its recommendation should be modified to include annual cost escalation.”[1120] Despite admitting this error, however, Cal Advocates continues to propose its testimony forecast of $3.924 million.[1121] At a minimum, Cal Advocates should be required adjust its forecast to reflect this error.

Cal Advocates also continues to argue “PG&E failed to meet its burden to prove 55,000 [riser repairs] is reasonable.”[1122] To further support its claim, Cal Advocates asserts that the number of risers needing corrective action has declined over the past three years, stating “between 2019-2021, PG&E identified an average of 24,835 risers per year for corrective action.”[1123] However, 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. It is this expansion of remediation requirements that drives the increase in riser repairs forecast by PG&E. 2019-2021 recorded data would there not reflect this increase.[1124]

For all these reasons, the Commission should adopt PG&E’s forecast for 55,000 service riser coating remediations at the soil-to-air interface, that is based on an engineering estimate of a five percent find rate applied to PG&E’s approximate 1.1 million annual service riser inspections.[1125]

1119 PG&E Opening Brief, p. 286.

1120 Cal Advocates Opening Brief, p. 86.

1121 CALPA-02, p. 53, Table 2-38.

1122 Cal Advocates Opening Brief, p. 86.

1123 *Id*.

1124 PG&E-16-E, p. 9-14, lines 12-23.

1125 PG&E-16-E, p. 9-12, lines 22-25.

3.8.3 GD Capital Corrosion Control (MATs 50D/50Q)

GD Capital Corrosion Control includes the following work activities: Rectifier Replacements (MAT 50D); Capital Coating Remediation of Spans > 100 feet (MAT 50D); and GD Capital Contacted Casing Remediation of Casings > 100 feet (MATs 50D/50Q).[1126] PG&E's GD Capital Casing Mitigation forecast for MAT 50D/50Q is $15.3 million in 2021 and $19.5 million in 2020.[1127]

Cal Advocates accepts PG&E's 2023 forecast but recommends that PG&E's 2021 forecast for MAT 50D/50Q, $15.3 million, be reduced by $4.5 million to $10.9 million; and that the PG&E's 2022 forecast, $19.5 million, be reduced by $8.7 million to $10.9 million. Cal Advocates' recommended 2021 and 2022 capital forecasts are based on PG&E's January-November 2021 recorded costs.[1128]

In its Opening Brief, PG&E responded to Cal Advocates' forecast and arguments, demonstrating that PG&E's 2021 and 2022 forecasts are reasonable and appropriate.[1129] Cal Advocates' proposal to replace PG&E's 2021 forecast with 2021 recorded costs is inappropriate because it predates PG&E's filing.[1130] The use of 2021 recorded data in this GRC is further discussed in Section 1.5 of PG&E's Opening Brief. In addition, even if 2021 actuals are used, Cal Advocates failed to use the full 2021 data provided by PG&E on March 9, 2022, more than 90 days prior to Cal Advocates' submission of its testimony.[1131] Actual 2021 recorded costs are

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1126 See PG&E-03, p. 9-19, lines 15-21 and p. 9-24, line 16 to p. 9-25, line 5 (MAT 50D - Rectifiers); p. 9-25, line 6 to p. 9-29, line 12 (MAT 50D – Atmospheric); and p. 9-30, lines 9-16 (MATs 50D/50Q – Casings). Mitigation of contacted casings greater than 100 feet was historically recorded to MAT 50D; however, this work transitioned to a new/dedicated MAT 50Q on January 1, 2021.

1127 PG&E-16-E, p. 9-26, Table 9-9, line 1.

1128 PG&E Opening Brief, pp. 286-287.

1129 PG&E Opening Brief, pp. 287-289.

1130 PG&E-16-E, p. 9-17, lines 14-19.

1131 PG&E Opening Brief, p. 287.

$11.3 million.[1132] In its Opening Brief, Cal Advocates states "Cal Advocates does not dispute the 2021 recorded cost for MAT 50Q of $11.3 million."[1133] Thus, if the Commission adopts 2021 recorded costs instead of PG&E's 2021 forecast, the correct number is $11.3 million, not $10.9 million.

Cal Advocates proposal to replace PG&E's 2022 forecast of $19.5 million with 2021 recorded costs (claimed to be $10.9 million) is not reasonable because it ignores the fact that PG&E forecasted completion of all backlog GD Capital Casing Mitigation projects in 2022 and the transition of the program to find it/fix it in 2023. Cal Advocates' recommendation would effectively place a cap on 2022 funding for GD Capital Casing Mitigation and result in projects being delayed until future years.[1134]

Cal Advocates further justifies its recommended 2021 and 2022 adjusted recorded capital forecasts of $10.9 million by claiming that "with the exception of 2019, PG&E's recorded annual capital expenditures from 2016-2020" and January-November 2021 were $10 million or less.[1135] However, 2017-2019 total recorded expenditures do not provide a reasonable basis to forecast the program in 2022 because this program was in transition from developmental in the 2017 GRC (2017-2019) to full scale in the 2020 GRC (2020-2022).[1136]

As discussed in PG&E's Opening Brief, Cal Advocates' claim that PG&E underspends Commission -authorized capital expenditure funding for casing mitigation is flawed since it relies on spending in a different MAT code.[1137] In its Opening Brief, Cal Advocates further claims that "PG&E does not explain how completing the backlog projects by 2022 is achievable

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1132 PG&E-16-E, p. 9-17, lines 6-10.

1133 Cal Advocates Opening Brief, p. 92.

1134 PG&E Opening Brief, pp. 287-288.

1135 CALPA-02, p. 63, lines 1-8.

1136 PG&E Opening Brief, p. 287.

1137 PG&E Opening Brief, p. 287.

given its history of underspending."[1138] Specifically, Cal Advocates claims that PG&E "fails to explain the discrepancy between mitigation projects PG&E completed as of November 30, 2021 (41 projects) and mitigation projects PG&E forecasted for 2021 (72)." However, as explained in PG&E's testimony, the performance of casing work during the 2020-2022 period was affected by disruptions caused by the COVID 19 global pandemic. These impacts included an approximate two month shut down of work, followed by restrictions and commensurate reduction of contractor resources.[1139] These impacts have resulted in the need to perform additional work in 2022. The data cited by Cal Advocates is therefore 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.

Finally, in its Opening Brief, Cal Advocates argues that "the Commission should impose a negative evidentiary inference against PG&E where there is inadequate record for, or confusion about, how migrated or transitioned work supports the revenue request."[1140] This proposal is completely unwarranted. PG&E has clearly and transparently explained the MAT code realignment:

> Mitigation of contacted casings greater than 100 feet was historically recorded to MAT 50D; however, this work transitioned to a new / dedicated MAT 50Q on January 1, 2021.[1141]

As PG&E explained "the GD Capital Casing Mitigation program did not exist until 2017. [The program transitioned] from developmental in the 2017 GRC (2017 2019) to full scale in the 2020 GRC (2020-2022)."[1142] The development of the new program and creation of a new MAT code

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1138 Cal Advocates Opening Brief, p. 93.

1139 PG&E-03, p. 9-77, line 3 to p. 9-78, line 20 (explaining impacts on expense casings) and WP-9-103, Table 9-60, line 8.

1140 Cal Advocates Opening Brief, p. 91.

1141 PG&E-16-E, p. 9-16, fn. 33.

1142 PG&E-16-E, p. 9-18, lines 12-17.

(50Q) to capture this work was done for valid operational and work management reasons and not to cause any confusion as Cal Advocates implies.

3.8.4 GT&S Corrosion Control Capital Expenditures (MAT 3K1, 3K4, 3K9)

PG&E's GT&S Capital Corrosion Control programs included MATs 3K1, 3K4, and 3K9. PG&E's forecast for 2021 for these programs are shown in parentheses: MAT 3K1, Internal Corrosion Program ($12.0 million); MAT 3K4 AC Interference Program ($11.7 million); and MAT 3K9, DC Interference Program ($10.4 million).[1143] Cal Advocates proposes that PG&E's 2021 forecasts for these three MAT codes be replaced by January-November 2021 recorded expense.[1144] This results in a 2021 GT&S Capital Internal Corrosion Mitigation forecast for MAT 3K1 of $1.4 million; a 2021 GT&S Capital AC Interference forecast for MAT 3K4 of $3.4 million; and a 2021 GT&S Capital DC Interference forecast for MAT 3K9, of $6.8 million. Cal Advocates does not challenge PG&E's 2022 or 2023 forecasts for these programs.

Cal Advocates' recommendation to replace PG&E's 2021 forecast with November 30, 2021 recorded capital expenditures should be rejected. PG&E's 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 Commission's Rate Case Plan. Cal Advocates' proposal to replace PG&E's 2021 forecast with 2021 recorded financials is addressed in more detail in Section 1.5 of PG&E's Opening brief.[1145]

PG&E also pointed out in its Opening Brief that Cal Advocates' forecasts were based on partial-2021 data and should be replaced with the full year recorded costs. In its Opening Brief, Cal Advocates states that it "does not object to the Commission adopting PG&E's 2021 recorded expenditures for MATs 3K1, 3K4, and 3K9." Accordingly, if the Commission decides to replace

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1143 PG&E-16-E, p. 9-20, lines 7-13.

1144 PG&E-16-E, p. 9-20, line 20 to p. 9-21, line 2.

1145 PG&E-16-E, p. 9-21, lines 12-20.

PG&E's forecast with 2021 actuals it should adopt the following: $1.3 million (MAT 3K1); $3.3 million (MAT 3K4); and $7.4 million (MAT 3K9).[1146]

3.8.5 The Internal Corrosion Balancing Account (ICBA)

Cal Advocates' proposal to continue the ICBA[1147] is addressed in Section 3.14.3.3 of this Reply Brief.

3.9 Gas Operations Leak Management[1148]

PG&E's Leak Management programs consist of gas leak surveys and leak grading, gas leak repairs, and gas service and main replacements when needed to remediate gas leaks. PG&E's Leak Management programs mitigate safety and 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 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. In this section of our Reply Brief, we address issues regarding our Leak Management program forecasts raised by parties in their Opening Briefs:

TABLE 3-9
LEAK MANAGEMENT PROGRAM DISPUTED PROGRAMS

Section	Disputed Program	Party
3.9.1	Below Ground Distribution Main Leak Repair	Cal Advocates
3.9.2	Distribution Meter Set Leak Repair	Cal Advocates
3.9.3	Below Ground Distribution Service Replacement	Cal Advocates
3.9.4	Transmission Leak Repair	TURN, Cal Advocates

1146 PG&E-16-E, 9-21, lines 9-11.

1147 Cal Advocates Opening Brief, pp. 125-126, Section 3.14.3.4.

1148 Gas Operations Leak Management is addressed in Chapter 10 of PG&E's Prepared Testimony, PG&E-03, and further addressed in Chapter 10 of PG&E's Rebuttal Testimony, PG&E-16-E.

Cal Advocates' proposal to discontinue the New Environmental Regulations Balancing Account (NERBA) is addressed in Section 3.14.3.4 of this Reply Brief.

3.9.1 Below Ground Distribution Main Leak Repair (MAT FIG)

Below Ground Distribution Main Leak Repair is the work to repair leaks on gas distribution mains.[1149] PG&E's main leak repair complies with the work required by federal regulations. PG&E's 2023 forecast for this program is $33.7 million.[1150] Cal Advocates is the only party that addresses this program and proposes a reduction of $7.4 million reflecting a lower leak find rate and a lower unit cost per repair than PG&E's forecast.[1151] PG&E addressed Cal Advocates' recommendation to reduce the forecast in its Opening Brief.[1152] PG&E addresses Cal Advocates' further Opening Brief arguments below.[1153]

3.9.1.1 PG&E's Leak Find Rate Is Reasonable

In its Opening Brief, PG&E described how it derived its 2.04 percent leak find rate.[1154] PG&E also showed why Cal Advocates' 0.84 percent leak find rate is flawed.[1155] Specifically (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

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1149 PG&E-03, p. 10-29, line 19 to p. 10-30, line 9.

1150 PG&E-16-E, p. 10-3, Table 10-1, line 9. This forecast is net of a $12.7 million errata reduction that is explained in PG&E-16-E, p. 10-8, lines 11-19.

1151 CALPA-02, p. 74, lines 9-16.

1152 PG&E Opening Brief, pp. 292-294, Section 3.9.1.

1153 Cal Advocates Opening Brief, pp. 96-101, Section 3.9.1.1.

1154 PG&E Opening Brief, pp. 292-293, Section 3.9.1.1.

1155 PG&E Opening Brief, pp. 292-293.

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 due to Call-ins from customer odor complaints.

In its Opening Brief, Cal Advocates offers further arguments to support its low 0.84 leak find rate. These arguments are flawed as discussed below.

First, Cal Advocates argues that its 0.84 percent leak find rate is justified because "[t]he number of found leaks is decreasing."[1156] However, as discussed above, Cal Advocates' approach does not result in a representative or accurate find rate because it relies on the single lowest year (2021) to establish a forecast that covers only one-third of the total system survey, and also excludes the volume of call in leaks. Cal Advocates' recommendation does not align with PG&E's three-year compliance survey and only accounts for a portion of the system. The conditions of the survey areas within each year vary, thus resulting in different leak find rates.[1157] In contrast, PG&E's 2.04 percent leak find rate is based on three-year (2018-2020 June YTD)[1158] actual leak find rates and includes customer odor complaints.

Second, Cal Advocates argues that PG&E's methodology for determining its 2.04% leak find rate is "confusing [and] leaves much unexplained."[1159] Specifically, Cal Advocates claims "PG&E used an undefined "blend" of 2018-2020 data in its calculation instead of an average from the same period." However, in its Rebuttal Testimony PG&E clearly explained its methodology:

> PG&E's leak "find rate per 1 thousand services surveyed" for each leak grade are based on a blend of 2018-2020 June YTD actuals broken down by Division.[1160] Using these find rates, PG&E forecast 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

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1156 Cal Advocates Opening Brief, p. 97.

1157 PG&E-16-E, p. 10-10, lines 20-23.

1158 PG&E-16-E, p. 10-9, lines 4-12.

1159 Cal Advocates Opening Brief, p. 98.

1160 PG&E-03, WP 10-39, Workpaper Table 10-34, fn. A.

> and obtained a total 2023 forecast leak volume of 27,739.[1161] This total, divided by the total leak survey volume of 1,361,716 units,[1162] yields PG&E's overall find rate of 2.04%.[1163]

Furthermore, PG&E's workpapers provide a step-by-step explanation of how the division leak find rate data was used to calculate the forecast.[1164] Thus there is no mystery in PG&E's methodology or calculations as Cal Advocates claims.

Third, Cal Advocates claims that "PG&E's argument that Cal Advocates 'does not align with the three-year compliance leak survey cycle' fails to substantiate the company's confusing leak-find rate methodology and raises alarming implications."[1165] However, unlike Cal Advocates' leak rate that is based on data from a single year (2021), PG&E's leak find rate methodology is based on leak find data from each division for the most recent three year period prior submitting its forecast (2018-2020 YTD). Table 10-34, WP 10-39 clearly shows this.[1166] Furthermore, there is nothing alarming about PG&E's statement

> The conditions of the survey areas within each year vary, thus resulting in different leak find rates. These conditions include different pipe age, material, and environmental factors such as soil conditions and location within the service

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1161 These steps are all set forth in PG&E-03, WP 10-33, Workpaper Table 10-28, lines 1-10.

1162 PG&E-03, WP 10-41, line 100.

1163 PG&E-16-E, p. 10-9, lines 4-12.

1164 PG&E-03, WP 10-39, Table 10-34, shows a table of leak rates by division and leak type. The Forecast Number of Leaks Found by Grade is then calculated using the division data and is shown in WP 10-38, Table 10-33. In WP 10-37, Table 10-32, the Forecast Leak Find Rate by Leak Type is then calculated for each year by dividing the Forecast Number of Leaks Found by Grade from WP 10-38, Table 10-33 by the No. of Surveys per Year. Finally, WP 10-33, Table 10-28, calculates the Forecast Leak Volume for 2023 by Leak Type, multiplying leak find rates from WP 10-37, Table-10-32 by the forecasted leak survey volume for 2023. After adding Leak Find Volume from Call-Ins, the sum of the leak volumes by grade is the 27,739 total leak forecast for 2023 (WP 10-33, Table 10-28, line10).

1165 Cal Advocates Opening Brief, p. 99.

1166 The only exception as explained in note (B) of PG&E-03, WP 10-39, Table 10-34, is for Above Ground Grade 2 and 3 leaks: "AG2 & AG3 only uses 2020 YTD thru June to account for the change in procedure [that] categorizes above ground riser thread leaks as non-gradable moving forward."

> territory. As a result, a single year find rate is not representative of the true, average historical find rate.[1167]

It stands to reason that a leak rate based on survey data that represents all of PG&E's system, and not on just on survey data that covers one third of the system, is a better measure of the leaks that PG&E is likely to encounter over the 4-year GRC cycle. PG&E's leak rate is based on survey data from 2018 to 2020 and thus includes find rates for the entire system. Cal Advocates uses 2021 data, covering only one third of the system, which is much less likely to be representative of area-to-area and year-to-year variations.

Finally, Cal Advocates accuses PG&E of failing to provide information about customer call-ins.[1168] However, PG&E's workpapers clearly show this information. Table 10-28, WP 10-33 that calculates the forecast leak volume for 2023, has a column "Leak Find Volume from Call-Ins" that shows the call-in volume by type of leak. Footnote (C) explains the source of the call-in data.

For all these reasons, the Commission should reject Cal Advocates' low leak 0.84% find rate and adopt PG&E's leak find rate of 2.04%.

3.9.1.2 PG&E's 2023 Forecasted Unit Cost Is Reasonable

PG&E's 2023 forecasted unit cost for leak repairs is based on 2020 recorded costs plus a 3.75 percent escalation due to annual Internal Brotherhood of Electrical Workers (IBEW) wage increases.[1169] Cal Advocates' unit cost is based on 2021 recorded costs divided by 2021 recorded leak repairs as of November 30, 2021.[1170] As discussed in PG&E's Opening Brief, Cal Advocates unit cost is flawed because it is based on 2021 data not available at the time of

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1167 PG&E-16-E, p. 10-10, lines 22-26.

1168 Cal Advocates Opening Brief, p. 98-99.

1169 PG&E-03, WP 10-47, lines 13-26.

1170 CALPA-02, p. 79, lines 19-21 and p. 80, Table 2-63.

filing; used partial-2021 data; and does not include the 3.75 percent escalation to account for the IBEW annual wage increase.[1171]

In its Opening Brief, Cal Advocates agrees that escalation should have been applied and states, "[a]ccounting for this escalation increases Cal Advocates' recommendation to $8,193 per unit."[1172] Regardless of this correction, however, PG&E requests that the Commission reject Cal Advocates unit cost because it is based on 2021 data, and instead adopt PG&E's unit cost of $8,871 that is based on 2020 base-year recorded costs.[1173]

3.9.2 Distribution Meter Set Leak Repair (MAT FIS)

Meter Set Leak Repair is the work to repair non-hazardous leaks on gas meter sets.[1174] PG&E forecasts 139,749 meter repairs in 2023 at a total forecasted expense of $16.2 million.[1175] Repair of non-hazardous meter set leaks within 36 months is required pursuant to PG&E's internal Work and Compliance Matrix.[1176] Cal Advocates is the only party that addresses this program and proposes a reduction of $8.7 million based on a lower number of repair units and a lower unit cost per repair compared to PG&E's proposal.

PG&E responded to Cal Advocates' arguments in its Opening Brief,[1177] and responds to Cal Advocates' further Opening Brief arguments below.[1178]

1171 PG&E Opening Brief, pp. 293-294, Section 3.9.1.2.

1172 Cal Advocates Opening Brief, p. 101.

1173 PG&E Opening Brief, pp. 293-294.

1174 PG&E-03, p. 10-30, line 12 to p. 10-31, line 4.

1175 PG&E-16-E, p. 10-12, lines 19-27.

1176 PG&E-03, p. 10-30, lines 19-22.

1177 PG&E Opening Brief, pp. 294-298, Section 3.9.2.

1178 Cal Advocates Opening Brief, pp. 101-104, Section 3.9.1.2.

3.9.2.1 PG&E's Forecasted Units Are Reasonable

PG&E used historical average find rates from 2018 to 2020 YTD June plus an additional 10 percent to address pending units to achieve a target of approximately 70,000 pending meter set leak repair units by the end of this rate case cycle. PG&E's 9.48 percent leak find rate (*i.e.*, number of expected leaks on services surveyed) is based on a combination of meter set leaks at 8.08 percent and riser thread leaks at 1.4 percent.[1179] Cal Advocates' method for calculating a lower 7.4 percent leak find rate is flawed because it (1) is not an accurate representation of the leak finds year over year because it is based on a single year of data and does not align with PG&E's three-year compliance survey;[1180] (2) would allow the pending meter set leak volume to continue to grow year over year and would not allow leaks to be repaired within a 36-month time frame as required by PG&E's Work and Compliance Matrix;[1181] and (3) under-counts total leaks because it fails to recognize that PG&E's Leak Grading procedure was updated in March 2020 which reallocated riser thread leaks to MAT FIS.[1182]

In its Opening Brief, Cal Advocates makes the following additional arguments.[1183]

First, Cal Advocates argues that "PG&E's request is excessive and meter repair should continue at the historic level. [¶] From 2016 to November 30, 2021, PG&E's annual repair costs for MAT FIS did not exceed $7 million."[1184] However, because riser thread leaks have now been added to MAT FIS leak repair, this historic comparison is inappropriate. The recorded costs shown in Cal Advocates' testimony reflect FIS costs prior to this change.[1185] As shown in Cal Advocates' testimony, riser thread leaks will add over $3.5 million to the annual cost of FIS

1179 PG&E Opening Brief, pp. 295-297, Section 3.9.2.1.

1180 PG&E Opening Brief, p. 296.

1181 PG&E Opening Brief, p. 296-297.

1182 PG&E Opening Brief, p. 297.

1183 Cal Advocates Opening Brief, pp. 101-104, Section 3.9.1.2.

1184 Cal Advocates Opening Brief, p. 101.

1185 CALPA-02, p. 82, Table 2-65.

leak repair.[1186] The remainder of the requested increase in PG&E's proposed forecast for FIS would allow PG&E to repair the volume of annual leak finds and meet the Company's objective of a maintaining a steady-state backlog of approximately 70,000 pending non-hazardous meter set leaks, and not having this backlog continue to grow.[1187] PG&E seeks to repair non-gradable leaks within a 36-month time frame as required by PG&E's Work and Compliance Matrix.[1188] 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."[1189] This statement only makes sense if adequate funding is granted: MAT FIS is 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.

Second, Cal Advocates argues that "PG&E's explanation for its find-leak rate is confusing and flawed."[1190] However, PG&E has clearly explained its forecast for this MAT code that is composed of meter set repairs and riser thread repairs that were recently moved to this MAT code due to a change in grading policy:

> PG&E determined a 9.48 percent of leak find rate based on a combination of meter set leaks at 8.08 percent and riser thread leaks at 1.4 percent. The meter set leak find rate is based on a three-year average (2018-2020 YTD June) of recorded finds divided by total services leak surveyed.[1191] The riser thread leaks find rate is based on a blended leak find rate of above ground Grade 2 and 3 leaks from 2018-2020 YTD June minus the 2020 YTD June leak find rate to calculate the

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1186 CALPA-02, p. 82, Table 2-66.

1187 PG&E-03, p. 10-30, lines 15-19.

1188 PG&E-03, p. 10-30, lines 19-22.

1189 Cal Advocates Opening Brief, p. 102.

1190 Cal Advocates Opening Brief, p. 102.

1191 PG&E-03, WP 10-58, lines 1-5.

> incremental find rate to MAT FIS.[1192] The adjustment was to account for leaks that were removed from MAT FIH and categorized under MAT FIS instead due to a change to PG&E's Leak Grading procedure which reallocated riser thread leaks as non-gradable leaks. This allowed PG&E to account for the procedure change that went into effect in 2020.[1193]

The riser thread leak find rate calculations are detailed in PG&E's work papers, Table 10-36, WP 10-46.

3.9.2.2 PG&E's 2023 Forecasted Unit Cost Is Reasonable

PG&E's 2023 forecasted unit cost is based on a combination of costs to repair meter set leaks, and cost to repair riser thread leaks, broken down by Field Services and Maintenance & Construction (M&C).[1194] Cal Advocates' unit cost is based on 2021 recorded costs of meter set repairs divided by 2021 recorded leak repairs (both as of November 30, 2021) and similarly for riser thread leaks.[1195]

Cal Advocates' approach is flawed because it does not take into consideration a full years' work, meaning the 2021 recorded data used was as of November 31, 2021. Also, Cal Advocates uses 2021 data which was not available at the time PG&E filed on June 30, 2021. This is inconsistent with the base year of 2020 recorded costs used in accordance with the Commission's Rate Case Plan.[1196] The use of 2021 recorded data in this GRC is further discussed in Section 1.5 of PG&E's Opening Brief.

3.9.3 Below Ground Distribution Service Replacement (MAT 50G)

Simple service replacement is the work to replace or deactivate entire or stub services due to leaks and complies with federal regulations.[1197] Cal Advocates' forecast exceeds PG&E's revised forecast of $14.4 million due to a post-February 28, 2022 forecast reduction by PG&E of

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1192 PG&E-03, WP 10-46, lines 1-8.

1193 PG&E-16-E, p. 10-13, lines 16-27.

1194 See PG&E-03, WP 10-62, Table 10-51.

1195 PG&E-16-E, p. 10-17, lines 1-3.

1196 PG&E-16-E, p. 10-17, lines 6-11.

1197 PG&E-03, p. 10-33, lines 2-26.

$7.3 million.[1198] PG&E's forecast reduction is due to correction of an error in the use of historical MAT code splits used to determine the leak repair forecast that results in a 2023 unit forecast of 978 rather than the 1,476 in PG&E's February 28, 2022 forecast.[1199] PG&E recommends that the Commission adopt PG&E's adjusted forecast of $14.4 million which is lower that Cal Advocates' forecast.[1200] In its Opening Brief, Cal Advocates appears to accept PG&E's revised forecast.[1201]

3.9.4 Transmission Leak Repair (MAT JOP)

Transmission leak repair is the work to repair leaks on gas transmission facilities. PG&E's transmission leak repair complies with the work required by GO 112-F and Leak Abatement Best Practice 21.[1202]

Cal Advocates agrees with PG&E's forecast for number of units for Grade 1 and Grade 2 above ground and below ground leaks. However, Cal Advocates disagrees with PG&E's above ground Grade 3 leak unit forecast, and recommends a $7.2 million reduction.[1203] TURN recommends adopting a five-year average (2016-2020) unit cost instead of PG&E's proposed two-year average (2019-2020) unit cost, and recommends a $1.2 million reduction.[1204]

1198 PG&E-16-E, p. 10-5, Table 10-3 line 1 and p. 10-6, Table 10-4, line 1. See PG&E-16-E, p. 10-31, Table 10-7, line 3 for PG&E's adjusted forecast for 2021 through 2026.

1199 PG&E-16-E, p. 10-18, lines 6-8.

1200 PG&E Opening Brief, pp. 298-299, Section 3.9.3.

1201 Cal Advocates Opening Brief, p. 106, Section 3.9.2.

1202 PG&E-03, p. 10-43, line 7 to p. 10-44, line 8. Under Best Practice 21 adopted in the Leak Abatement OIR, all leaks must be repaired within three years of discovery, except for leaks that are costly to repair relative to their size. D.17-06-015, p. 159, OP 5 and p. 153, COL 23.

1203 CALPA-02, p. 92, lines 9-14.

1204 TURN-05, p. 13.

PG&E responded to Cal Advocates' and TURN's proposed reductions in its Opening Brief,[1205] and addresses further arguments made by Cal Advocates[1206] and TURN[1207] in their Opening Briefs below.

3.9.4.1 PG&E's Forecast of Grade 3 Transmission Leak Repairs Is Reasonable

The 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.[1208] At the time PG&E developed its GRC forecast, only data for 2020 YTD June was available.[1209] TURN accepts PG&E's 2023 unit count, but Cal Advocates contests the above ground Grade 3 leak forecast.

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 the 2018 and 2019 leaks because PG&E should have already resolved them by 2023."[1210] However, PG&E's 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.[1211] 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 ground Grade 3 leaks from 2020 and not 2019.[1212] Moreover, by using the 2020 YTD June above ground Grade 3 leak count, Cal Advocate's calculation does not take into consideration leaks found in the

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1205 PG&E Opening Brief, pp. 300-302, Section 3.9.4.

1206 Cal Advocates Opening Brief, pp. 105-106, Section 3.9.1.3.

1207 TURN Amended Opening Brief, pp. 311-312, Section 3.9.1.

1208 PG&E-16-E, p. 10-20, lines 27-29.

1209 PG&E-16-E, p. 10-20, lines 25-30.

1210 Cal Advocates Opening Brief, p. 106.

1211 PG&E Opening Brief, pp. 300-301.

1212 PG&E-03, WP 10-66, line 41, fn. F.

second half of 2020 that will require repair by 2023. Cal Advocates therefore significantly understates the above Ground Grade 3 leak count for 2020.[1213]

Furthermore, Cal Advocates' speculation that PG&E's forecast somehow shows that PG&E has not been repairing above ground Grade 3 leaks within 36 months[1214] is wholly without basis. There is no evidence that PG&E has not been complaint with its leak repair obligations and timelines.

For these reasons, the Commission should adopt PG&E's 2023 above ground Grade 3 leak repair forecast that is based on an estimate of active open leaks in 2020, and must be repaired within 3 years, i.e., in 2023.

3.9.4.2 PG&E's Proposed Unit Cost Is Reasonable

PG&E's 2023 forecasted unit cost for meter set repair is based on a 2-year average. TURN recommends that instead of PG&E's 2-year average, the unit cost be based on a five-year average, due to the significant annual fluctuation in average annual unit costs.[1215] TURN's approach is flawed because the Best Practice 21 requirement that above ground Grade 3 be repaired within 36 months was not in effect until 2017 and thus the costs in 2016 and part of 2017 were less. In addition, prior to 2019, Gas Pipeline Operations and Maintenance (GPOM) performed leak survey at facilities as part of routine maintenance, and leak repairs were captured as correctives under MWC JP rather than gradable leaks under MAT JOP. In 2019, this work was transitioned to the leak survey department resulting in higher leak find rates.[1216] For these reasons data from the years 2016-2018 used as part of TURN's unit forecast do not reflect the work currently being performed in MAT JOP[1217] and the Commission should adopt PG&E's

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1213 PG&E-16-E, p. 10-21, lines 6-17.

1214 Cal Advocates Opening Brief, p. 105.

1215 TURN Amended Opening Brief, p. 312.

1216 PG&E-03, p. 10-44, lines 2-7.

1217 PG&E-16-E, p. 10-22, line 25 to p. 10-23, line 7.

approach that is based on a two-year average (2019-2020) that captures the work being performed in this program.

3.9.5 New Environmental Regulations Balancing Account (NERBA)

Cal Advocates' proposal to discontinue the NERBA[1218] is addressed in Section 3.14.3.4 of this Reply Brief.

3.10 Gas System Operations[1219]

PG&E's Gas System Operations (GSO) function is responsible for maintaining sufficient design day capacity on the system, and for planning and operating the GD and GT&S system. The GSO forecast also includes engineering for local GD facilities and activities related to the manual operation of gas facilities in the field. The GSO function also covers the design of PG&E's GT&S system, including the capabilities of the backbone and storage facilities used to calculate costs and rates in other chapters. In this section of our Reply Brief, we address issues regarding our Gas System Operations program forecasts raised by parties in their Opening Briefs:

TABLE 3-10
GAS SYSTEM OPERATIONS DISPUTED PROGRAMS

Section	Disputed Program	Party
3.10.1	Gas Distribution Control Center (GDCC) Operations	Cal Advocates
3.10.2	Gas Distribution Manual Field Operations – Expense	Cal Advocates
3.10.3	GT&S Operations	Cal Advocates
3.10.4	Electric Power for Compressor Fuel and Other Electric Equipment	Cal Advocates
3.10.5	Gas Distribution SCADA Visibility Program – Remote Terminal Units	TURN
3.10.6	Gas Transmission SCADA Visibility Program	TURN
3.10.7	Gas Transmission Capacity for Load Growth	TURN

1218 Cal Advocates Opening Brief, pp. 123-124, Section 3.14.3.3.

1219 Gas System Operations is addressed in Chapter 11 of PG&E's Prepared Testimony, PG&E-03, and further addressed in Chapter 11 of PG&E's Rebuttal Testimony, PG&E-16-E.

3.10.1 Gas Distribution Control Center (GDCC) Operations (MAT FGA)

The GDCC enables GSO to mitigate operational gas distribution system 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 GDCC 24 hours a day, 7 days a week, to remotely monitor the gas distribution system, including key equipment, and to respond quickly to mitigate events that could occur despite PG&E's preventative efforts.[1220] PG&E forecasts $8.8 million in 2023 expense.[1221] Cal Advocates' originally proposed a reduction of $839,000 based on the disallowance of PG&E's forecast expenditures for the Gas Control Room Consolidation plan and disallowance of PG&E's forecast for the SCADA Predictive Health Analytics project.[1222] In its Opening Brief, however, Cal Advocates recommends $357,000 million less than PG&E to reflect a calculation error.[1223]

PG&E responded to Cal Advocates' proposed reduction in its Opening Brief,[1224] and addresses further arguments made by Cal Advocates[1225] in its Opening Brief below.

3.10.1.1 Cal Advocates' Proposed Reduction Includes Erroneous Costs

In its Opening Brief, PG&E identified an error in Cal Advocates' recommended disallowance.[1226] As discussed above, Cal Advocates has adjusted its recommendation to reflect this, and reduced its disallowance from $0.879 million to $0.357 million.[1227]

1220 PG&E-03, p. 11-38, lines 8-15.

1221 PG&E Opening Brief, p. 304, Table 3-58.

1222 CALPA-03, p. 6, lines 9-10 and lines 21-22; PG&E-16-E, p. 11-10, line 27 to p. 11-11 line 2.

1223 Cal Advocates Opening Brief, p. 107, fn. 520.

1224 PG&E Opening Brief, pp. 305-308.

1225 Cal Advocates Opening Brief, pp. 107-108, Section 3.10.1.

1226 PG&E Opening Brief, p. 305.

1227 Cal Advocates Brief, p. 107, fn. 520.

3.10.1.2 Costs Associated With PG&E's Consolidation Plan Are Recoverable

In its prepared testimony, PG&E proposed a reorganization of its gas system control center (Consolidation Plan) to operate the gas system under a geographical structure (north-south) rather than the current functional structure (distribution-transmission) in order to capture certain efficiencies and benefits. The reorganization was subject to approval by members of the IBEW.[1228] After filing the 2023 GRC on June 30, 2021, members of the IBEW voted to not adopt PG&E's proposed Gas Control Room Consolidation.[1229] In order to maintain safe operation of the gas system, PG&E plans to backfill the approximately six additional gas control operators and supervisors that were left vacant in preparation for implementation of the Gas Control Room Consolidation plan.[1230] PG&E forecasts that the cost of backfilling the six gas control operators and supervisor positions left vacant will exceed the incremental cost forecast for the Gas Control Room Consolidation plan described.[1231]

Cal Advocates argues in its Opening Brief 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'"[1232] However, PG&E's work papers do contain information that allows the incremental cost of hiring the additional Gas Control employees to be estimated.[1233] 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

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1228 The reorganization is described in PG&E-16-E, p. 11-12, line 24 to p. 11-13, line 18.

1229 PG&E-16-E, PG&E's response to Data Request CalAdvocates_252-Q003(e), dated 2/17/22, p. AppA-374.

1230 The Consolidation Plan would have allowed PG&E to operate with approximately six fewer FTE employees in the control room than would otherwise be required to operate each system resulting in savings. PG&E stated in its testimony that it had left six vacant positions unfilled in preparation for implementation of the Consolidation Plan. PG&E-16-E, p. 11-13, lines 17-18.

1231 PG&E-16-E, p.11-14, lines 9-11.

1232 Cal Advocates Opening Brief, pp. 107-108.

1233 PG&E-03, WP 11-19.

Control employee and by multiplying that cost by the six FTEs to be hired.[1234] This $1.586 million annual cost of hiring six additional Gas Control employees is nearly three times the cost of the 2021 Gas Control Consolidation forecast of $559,556.[1235]

The Commission should adopt PG&E's forecast despite the fact that the Gas Control Room Consolidation will not be implemented, because the six positions left vacant in anticipation of the consolidation will now need to be filled and will exceed the cost that would have been incurred to implement the consolidation.

3.10.1.3 The SCADA Predictive Health Analytics Work Is Reasonable

Cal Advocates claims PG&E has not shown that the Supervisory Control and Data Acquisition (SCADA)[1236] Predictive Health Analytics program that is now part of GDCC activities is a new expense that requires additional funding.[1237] However, Cal Advocates misunderstands the nature of this work. This is not new or additional work, but merely a shift to MAT FGA of existing work previously charged to other MAT codes.[1238] The SCADA Predictive Health Analytics was forecast as part of the 2019 GT&S Rate Case[1239] and the 2020

1234 See PG&E-03, WP 11-19. The additional cost per Gas Control employee can be calculated by taking the fully burdened hourly rate for 2023 (line 5) and multiplying that value of $127.16 by 2,080 working hours in a year ($127.16 * 2,080) = $264,493. The 2,080 hour annual working hours assumption is shown on line 6. The total cost of hiring six additional Gas Control employees can then be calculated by taking the additional cost per employee of $264,493 and multiplying that value by six ($264,493 * 6) = $1,586,958.

1235 PG&E-03, WP 11-21, line 13.

1236 PG&E's SCADA program provides pressure and flow data to the GDCC to provide 24/7 monitoring of the gas distribution system. SCADA devices are a central tool that provides GDCC operators visibility into the gas system. PG&E-16-E, p. 11-25, lines 8-12.

1237 CALPA-03, p. 7, lines 4-6.

1238 PG&E Opening Brief, pp. 307-308, Section 3.10.1.3.

1239 PG&E-16-E, p. 11-AtchB-1 to p. 11-AtchB-4 (Workpapers for MWCs JV and 2F from 2019 GT&S case (A.17-11-009), Exhibit (PG&E-13), WP 12-30 to WP 12-33).

GRC[1240] in MAT JVA and MAT 2FA as a technology project. In preparing the 2023 GRC 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 GRC is simply an accounting cost transfer for continuing activities and is not a new program to the GRC.[1241] PG&E is not forecasting any incremental headcount additions to perform SCADA Predictive Health Analytics work in this GRC.

Cal Advocates now argues "PG&E fails to explain why it modified the accounting codes for this work activity."[1242] However, as PG&E explained in testimony, in prior rate cases, the tools and predictive health methodologies to mine the data were continuously being developed and modified, and were therefore appropriately funded as part of ongoing information technology (IT) projects. However, as PG&E has since transitioned much of this work to ongoing standard work of analyzing the operational data provided by these foundational systems, it is not appropriate to continue recording these expenses to IT projects.[1243]

Accordingly, the Commission should adopt PG&E's full forecast for MAT FGA, including the costs for SCADA Predictive Health Analytics work which is simply a transfer of costs from the IT department to Gas Operations for the same activity.

3.10.2 Gas Distribution Manual Field Operations – Expense (MAT FGB)

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

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1240 PG&E-16-E, Attachment C, p. 11-AtchC-1 to p. 11-AtchC-3 (Workpapers for MATs JVA and 2FA from 2020 GRC (A.18-12-009), HE-14: Exhibit (PG&E-3), WP 11-28 to WP 11-30).

1241 PG&E-16-E, p. 11-15, lines 8-15.

1242 Cal Advocates Opening Brief, p. 108.

1243 PG&E-16-E, p. 11-14, line 27 to p. 11-15, line 4.

activities. Furthermore, when system demands are high, and to deal with other abnormal situations, personnel may be dispatched to operate certain field equipment manually.[1244]

PG&E based the 2023 forecast of $1.1 million on 2020 recorded expenses, plus escalation. Cal Advocates' proposed reduction of $226,000 is based on utilizing 2021 recorded expenditures as the basis for the 2023 forecast. Cal Advocates asserts that its proposed reduction is warranted because "PG&E's expenses decreased by over 10% per year on average for each year over the historical period 2016 and 2021."[1245]

PG&E addressed Cal Advocates' arguments in its Opening Brief.[1246] In summary (1) Cal Advocates' reduction is too steep, and does not address the potential variability of these operations and (2) PG&E also objects to Cal Advocates' use of 2021 recorded costs as the basis for the 2023 MAT FGB forecast.

In its Opening Brief, Cal Advocates continues to argue that the declining trend in MAT FGB costs justifies using 2021 costs instead if the base year of 2020.[1247] However, 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.[1248] 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.[1249]

Accordingly, the Commission should adopt PG&E's forecast which represents a reasonable balance between the declining trend and the continued variability of this work.

1244 PG&E-16-E, p. 11-15, line 26 to p. 11-16, line 3.

1245 CALPA-03, p. 8, lines 9-10.

1246 PG&E Opening Brief, pp. 308-309, Section 3.10.2.

1247 Cal Advocates Opening Brief, pp. 108-109.

1248 PG&E-16-E, p. 11-17, lines 9-14.

1249 PG&E-03, WP 11-3, Table 11-3, line 12.

3.10.3 GT&S Operations (MAT CMA)

PG&E requires 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 our SCADA and other GTCC systems, support customers using the system, and plan for capacity and operations on a daily and longer-term basis. These organizations are forecast under MAT CMA.[1250] PG&E's 2023 forecast for MAT CMA is $17.3 million. Cal Advocates proposes a $1.9 million reduction based on the disallowance of PG&E's forecast expenditures for the Gas Control Room Consolidation plan and the SCADA Predictive Health Analytics project, and the disallowance of PG&E's request for expenditures related to the hiring of five incremental gas transmission system planning employees.[1251]

PG&E responded to Cal Advocates proposed reduction in its Opening Brief,[1252] and addresses further arguments made by Cal Advocates[1253] in its Opening Brief below.

3.10.3.1 The Gas Control Room Consolidation Forecast Is Reasonable

As discussed in Section 3.10.1.1 above, in relation to the GDCC (MAT FGA), the IBEW voted to not adopt PG&E's proposed Gas Control Room Consolidation plan, and PG&E plans to backfill approximately six additional gas control operators and supervisors that were left vacant in preparation for implementation of the consolidation plan. Since the estimated $1.586 million[1254] annual cost of backfilling these positions is nearly three times the cost of the 2021 Gas Control Consolidation forecast of $559,556,[1255] Cal Advocates' proposal to disallow Gas Control Room Consolidation costs should be rejected.

1250 PG&E-03, p. 11-12, line 10 to p. 11-14, line 5.

1251 CALPA-3, pp. 6-10, summarized at PG&E-16-E, p. 11-18, lines 7-27.

1252 PG&E Opening Brief, pp. 309-312, Section 3.10.3.

1253 Cal Advocates Opening Brief, pp. 110-111, Section 3.10.3.

1254 This calculation is shown in Section 3.10.1.1 above.

1255 PG&E-03, WP 11-21, line 13.

3.10.3.2 SCADA Predictive Health Analytics

As discussed in Section 3.10.1.1 above in relation to the GDCC (MAT FGA), the SCADA Predictive Health Analytics program is not new or additional work and should be funded. The forecast presented in the 2023 GRC is simply an accounting cost transfer for continuing activities and is not a new program to the GRC.[1256] Thus there is no basis to remove these costs from PG&E's forecast.

3.10.3.3 Hiring Additional Gas Transmission System Planning (GSP) Employees Is Reasonable

As addressed in PG&E's Opening Brief,[1257] PG&E fully justified the need for five additional local transmission engineers citing a significant volume increase in gas system planning work associated with integrity management, integrated investment planning, and emergency support.[1258] Prior to the hiring of the five GSP engineers in May 2021, PG&E was unable to meet the observed volume of gas system planning requirements without additional support. This resulted in several transmission projects where GSP support was requested and unfulfilled.[1259] PG&E's GSP team also performed a workload study vs. resources that showed that PG&E's GSP team was projected to be understaffed by 17 percent by 2021.[1260]

In its Opening Brief, Cal Advocates continues to argue that PG&E has "failed to prove a need for [the] new employees."[1261] In light of the testimony and studies presented by PG&E,[1262] this is simply not true.

1256 PG&E-16-E, p. 11-15, lines 8-15.

1257 PG&E Opening Brief, pp. 311-312, Section 3.10.3.3.

1258 PG&E-16-E, p. 11-20, lines 24-29.

1259 PG&E-16-E, p. 11-21, lines 3-6.

1260 CALPA-37, PG&E's Response to Cal Advocates 283-Q001, dated 8/15/22, and Attachment 283-Q001Atch01.

1261 Cal Advocates Opening Brief p. 110.

1262 PG&E Opening Brief, pp. 311-312, Section 3.10.3.3.

Cal Advocates also argues that although PG&E hired the five employees in May 2021, PG&E fails to explain the similarity between 2021 and 2020 expenses.[1263] This observation, however, does not stand up to scrutiny. The cost of the additional engineers was only incurred for the second half of 2021, representing an incremental cost of approximately $0.5 million. This amount is within the kind of variability seen historically for this MAT code. For example, the 2019 cost of $12.4 million was approximately $0.5 million less than the 2016 recorded cost of $12.9 million.[1264] Thus, the fact that 2021 costs did not precisely increase by $0.5 million to reflect the five engineers that were hired does not demonstrate that these new hires are not a legitimate incremental cost for this MAT CMA that should be reflected in PG&E's forecast.

For all these reasons, the Commission should adopt PG&E's forecast for MAT CMA, including the incremental cost of hiring five new engineering staff.

3.10.4 Electric Power For Compressor Fuel And Other Electric Equipment (MAT CMB)

PG&E operates electric-powered gas compressors at Bethany and Delevan compressor stations on the backbone transmission system, at the McDonald Island storage facility, and on the local transmission system in Santa Rosa. Since customers cannot provide in-kind fuel for electric compressors, PG&E must obtain electricity to power them. To ensure that shippers pay the cost of this electric power, PG&E includes the costs of electricity for electric-powered gas compressors in rates. MAT CMB also includes the costs for electric power used by SCADA devices, station buildings, and other electric equipment on the transmission system.[1265]

PG&E recorded $27.0 million to MAT CMB in 2020, and is forecasting to spend $29.1 million in 2023, a $2.1 million increase.[1266] The forecast increase is driven by increased

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1263 Cal Advocates Opening Brief, p. 111.

1264 PG&E-03, WP 11-3, Table 11-3, line 3.

1265 PG&E-03, p. 11-43, line 27 to p. 11-44, line 13.

1266 PG&E-3-ES, p. iii.

electricity usage and higher electricity costs to run the electric gas compressor stations, and by forecast escalation.[1267] Cal Advocates' recommendation of $27.5 million for MAT CMB reduces PG&E's forecast by $1.6 million.[1268] Cal Advocates claims that its forecast "reflects the historical spending levels recorded from 2016 to 2020."[1269]

PG&E's proposal to use the base year 2020 recorded spend escalated and adjusted for higher forecast usage and electricity prices is a sound forecasting approach.[1270] Cal Advocates' historical 2016-2020 average cost comparison does not cover these expected increases adequately.

Cal Advocates argues in its Opening Brief that "PG&E's increase over the six-year average is excessive and inadequately supported."[1271] However, PG&E's use of the base year 2020 is appropriate where historic costs trend upwards, as they do with MAT CMB. The historic costs for the six-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 in 2020.[1272] Use of a 2016 to 2020 average is therefore not appropriate and does not capture the increasing trend.[1273]

For these reasons PG&E's forecast of the cost of Electric Power for Compressor Fuel and Other Electric Equipment, that uses the base year of 2020 escalated to 2023, is reasonable and should be adopted.

1267 PG&E-03, p. 11-47, lines 24-28.

1268 Cal Advocates Opening Brief, p. 112.

1269 CALPA-03, p. 11, lines 10-14.

1270 PG&E-03, p. 11-47, lines 13-28.

1271 Cal Advocates Opening Brief, pp. 111-112.

1272 PG&E-03, WP 11-3, Table 11-3, line 4.

1273 D.04-07-022, pp. 15-16 (if recorded costs show a certain trend, use of the base year is an appropriate basis for the test year forecast.)

3.10.5 Gas Distribution SCADA Visibility Program – Remote Terminal Units – Capital (MAT 4AM)

PG&E's GD SCADA program sends pressure and flow data to the GDCC to provide 24/7 monitoring of the gas distribution system. If the devices detect conditions that are out of the normal range, they send an alarm to the GDCC that is investigated and remediated. Data from SCADA devices also help GSP engineers validate and calibrate hydraulic models leading to more efficient designs and support predictive health analytics.[1274]

PG&E's GD SCADA visibility program (MAT 4AM) is focused on installation of remote terminal units (RTUs) that are capable of real time data transmission with multiple sensing capabilities, including pressure transmitters, pressure differential transmitters, switches, and other instruments.[1275] PG&E forecast a 2023 capital expense of $22.8 million for the GD SCADA program.[1276] PG&E's strategy is to provide 100 percent visibility into all hydraulically independent systems (HIS) containing 50 or more customers by 2025 to provide the GDCC with increased visibility into system performance that allows quicker identification and response to abnormal operating conditions.[1277]

TURN proposes to cancel the GD SCADA visibility program completely and provide no further funding.[1278] TURN claims that the RSE for this program shows that the value of the risk reduction from PG&E's proposed work would be minimal compared to the program's costs.[1279] TURN provides no other basis for cancelling the program.

1274 PG&E-16-E, p. 11-25, lines 8-18.

1275 PG&E Opening Brief, p. 314.

1276 PG&E Opening Brief, p. 315, Table 3-62.

1277 PG&E Opening Brief, p. 316.

1278 TURN-02, p. 139, lines 1-2.

1279 TURN-02, p. 124, lines 5-7.

PG&E addressed TURN's proposed cancellation of the GD SCADA program in its Opening Testimony.[1280] PG&E responds below to further arguments advanced by TURN in its Opening Brief.[1281]

3.10.5.1 The SCADA Visibility Program Is Justified And Reasonable And Should Not Be Cancelled Based On RSE Scores

PG&E provided extensive testimony discussing the operational and regulatory drivers justifying this program.[1282] No party, including TURN, addressed this testimony. Visibility by operators into the conditions of the system is central to the safety of PG&E's operations and is consistent with state and federal regulation to identify and mitigate the risk of abnormal operating conditions. SCADA is the chief tool used by the GDCC to ensure safe distribution system operations.[1283]

The justifications for the GD SCADA program can be summarized as follows: (1) PG&E is forecasting to install RTUs at the remaining 297 locations identified to provide 100 percent visibility into all hydraulically independent systems (HIS) containing 50 or more customers.[1284] To fully understand what is occurring in these systems, PG&E needs visibility of all the input gas sources to each HIS; (2) completing PG&E's GD SCADA network provides the GDCC the ability to implement a predictive approach to operating the system;[1285] (3) contrary to TURN's claim that PG&E has already installed the highest risk locations, only approximately 10 percent, or 30 locations out of the remaining 297 forecast SCADA installations on the GD system are

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1280 PG&E Opening Brief, pp. 314-319, Section 3.10.5.

1281 TURN Amended Opening Brief, pp. 318-327, Section 3.10.1.

1282 PG&E-03, p. 11-31, line 10 to p. 11-34, line 7, and p. 11-79, line 14 to p. 11-88, line 2; PG&E-16-E, p. 11-26, line 17 to p. 11-28, line 17.

1283 PG&E-16-E, p. 11-27, lines 14-18.

1284 PG&E Opening Brief, pp. 315-317, Section 3.10.5.1.

1285 PG&E 16-E, p. 11-28, lines 12-17.

classified as "low risk";[1286] [1287] and (4) PG&E's GDCC SCADA program also supports and enhances compliance with state and federal regulations requiring the installation of monitoring systems on PG&E's gas pipeline system to provide indications of abnormal conditions to address unsatisfactory operating conditions and to minimize hazards and systemic risks to the gas system, including accidents, explosions, fires, and dangerous conditions.[1288]

TURN did not address in testimony the operational justifications for this program. One example is the need to have a SCADA device on each HIS with 50 or more customers in order to have full visibility into gas system conditions. In Prepared Testimony, PG&E explained:

> PG&E's strategy is to provide 100 percent visibility into all HISs containing 50 or more customers by 2025. The term "100 percent visibility" means having at least one SCADA device to monitor each regulator station, and one to monitor the HIS's low-pressure region. Many HISs having between 50 and 500 customers can be monitored using only a single device to measure both the regulator station feed into the HIS and HIS low-pressure points, since pressure throughout such small systems varies relatively uniformly in response to load. HISs serving 500 or more customers require at least two devices, and often more, depending on the regulator station design (either spring or pilot operated), the HIS pressure (either high pressure, semi-high pressure or low pressure), the number of customers in the HIS, and the number of regulator stations that feed the HIS.[1289]

The operational importance of full SCADA deployment for each HIS with 50 or more customers is further explained in Section H.2.c of PG&Es' opening testimony.[1290] TURN did not address any of this testimony in its showing, implying that TURN does not believe full visibility into each Hydraulically Independent System is necessary. Other testimony unaddressed by TURN includes how SCADA provides the GDCC the situational awareness to more effectively predict conditions that may lead to abnormal events, diagnostic capabilities to

1286 PG&E-16-E, p. 11-30, lines 1-8; PG&E-16-E, Appendix A, PG&E's response to Data Request TURN_208-Q001, dated 5/24/22, p. AppA-381.

1287 PG&E Opening Brief, pp. 317-318, Section 3.10.5.2.

1288 PG&E Opening Brief, p. 316.

1289 PG&E-03, p. 11-32, lines 3-15.

1290 PG&E-03, p. 11-82, line 22 to p. 11-83, line 17.

determine 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;[1291] PG&E's risk-based prioritization approach for SCADA deployment;[1292] and PG&E's cost-saving and value-based project execution strategy.[1293]

Instead, relying on a witness with no experience related to gas operations,[1294] TURN cites the relatively low RSE score for this program as the reason for cancelling the program.[1295] Using RSE scores in this way is not appropriate as explained in PG&E's Opening Brief Sections 2.3 and 3.2.2.[1296] While TURN faults PG&E for not explaining adequately, in TURN's view, how RSE scores were considered in its forecast for the GD SCADA program,[1297] by relying solely on the RSE score, TURN ignores the S-MAP Settlement Agreement[1298] that states RSEs are not meant to be the sole determining factor regarding whether risk control or risk mitigation programs should be selected for funding.

TURN advances additional arguments in its Opening Brief that are addressed below.

1291 PG&E-03, p. 11-83, lines 7-12.

1292 PG&E-03, p. 11-83, line 18 to p. 11-84, line 15.

1293 PG&E-03, p. 11-84, line 16 to p. 11-87, line 11.

1294 PG&E Opening Brief, pp. 318-319, "TURN witness Lesser . . . has not worked as an employee of a natural gas transmission or distribution utility; is not an expert on PHMSA regulations; and has no experience working on any committee of the AGA. In contrast, Mr. Menegus was the Senior Director of GSO whose responsibilities include: Gas Control and Gas Emergency Response, Gas System Hydraulic Planning, Gas Transmission Project Engineering and oversight of various engineering and support organizations, computerized systems, and technologies that enable the GSO function to be performed. Mr. Menegus . . .has 36 years of experience in engineering design of gas pipeline and station facilities; project management; system operations; operations and maintenance engineering; strategic planning; quality assurance; and developing new gas technologies. He has served as chair of the AGA Task Group on Automated Valves and served on the Interstate Natural Gas Association of America Task Force on Emergency Preparedness and Response."

1295 TURN-02, p. 123, lines 6-8.

1296 PG&E Opening Brief, p. 318.

1297 TURN Amended Opening Brief, p. 323.

1298 D.18-12-014, Attachment A, Appendix A, p. A-14, No. 26.

First, TURN's position in this case appears to be that RSE scores nullify all other justifications and reasons given by PG&E for these programs and overrides the opinions of PG&E's experts. TURN calls PG&E's program drivers "qualitative arguments" contrary to the Commission's multi-year efforts to inform the record with quantitative RSE analysis that allows prioritization of risk reduction proposals.[1299] The mere existence of RSE scores, however, does not mean that the Commission should ignore drivers such as the need to obtain 100% visibility into all Hydraulically Independent Systems containing 50 or more customers; the need for predictive tools to manage the system safely; and the need to install the remaining RTUs, 90 percent of which are high or medium risk. RSE scores should also not be used to dismiss the judgment of highly experienced experts such a PG&E's witness who are responsible for the safety of PG&E's system, especially when TURN has not provided testimony by an expert qualified in gas system operations.

Second, TURN down-plays the relevance of state and federal regulations that requiring the installation of monitoring systems on PG&E's gas pipeline system.[1300] These regulations are summarized in PG&E's testimony[1301] and Opening Brief.[1302] While PG&E's program goes beyond the minimum requirements of federal and state regulations, the program supports the intent of these regulations that operators install appropriate and effective system controls. As PG&E explained:

> The GD SCADA program supports and enhances compliance with state and federal regulations that requires the installation of monitoring systems on PG&E's GD system by having multiple points of visibility in a hydraulically independent system (HIS) in the event a SCADA asset fails. GD SCADA program is part of PG&E's efforts to apply industry best practices to its Gas Control function.[1303]

1299 TURN Amended Opening Brief, p. 324.

1300 TURN Amended Opening Brief, pp. 325-326.

1301 PG&E-03, p. 11-81, line 24 to p. 11-82, line 3.

1302 PG&E Opening Brief, p. 316.

1303 TURN-129, PG&E's Response to DR TURN_230-Q002.i.

This approach is also consistent with state law that encourages operators to exceed minimum requirements and apply best practices.[1304]

Finally, TURN argues that the GD SCADA program is classified by PG&E as a Type 4 "risk reduction" program, meaning PG&E views the program as discretionary.[1305] While under PG&E's Risk Based Portfolio Prioritization Framework the GD SCADA program is categorized as Work Type 4, which includes "discretionary" risk reduction initiatives, Subject Matter Expert input and judgment regarding the operational need for programs are a critical part of the prioritization process.[1306] In other words, Type 4 work can nevertheless be required based on the judgment of the managers and experts responsible for the safety of the assets. As PG&E's witness Dan Menegus, the Senior Director of Gas System Operations (GSO) responsible for Gas Control and Gas Emergency Response, Gas System Hydraulic Planning, Gas Transmission Project Engineering and oversight of various engineering and support organizations, computerized systems, and technologies that enable the GSO function to be performed testified:

> In my professional judgment, the remainder of the GD SCADA Visibility program is central to PG&E's obligation to put safety at the forefront of our operations and is consistent with state and federal regulation to identify and mitigate the risk of abnormal operating conditions. SCADA is the chief tool used by the GDCC to ensure safe distribution system operations. . . . Completing PG&E's GD SCADA network provides the GDCC the ability to implement a predictive approach to operating the system. . . . the GD SCADA program is the most effective method to safely and reliably monitor the GD system, allowing GDCC personnel to investigate potential abnormal conditions before they escalate into emergencies and to dispatch field personnel in an efficient and effective manner rather than relying on notifications from the public or emergency response personnel before actions can be initiated.[1307]

1304 California Public Utilities Code Section 961(b), (c) and (d): "Each gas corporation shall develop a plan for the safe and reliable operation of its commission-regulated gas pipeline facility" that "shall be consistent with best practices in the gas industry" and "[m]eet or exceed the minimum standards for safe design, construction, installation, operation, and maintenance of gas transmission and distribution facilities prescribed by regulations."

1305 TURN Amended Opening Brief, p. 320, and fn. 937.

1306 PG&E-16-E, p. 6-21, fn. 29 and PG&E-03, p. 2-22, lines 16-18.

1307 PG&E-16-E, p. 11-27, line 14 to p. 17-28, line 17.

For these operational and risk related reasons, the SCADA program is necessary and consistent with PG&E's designation of the work as Work Type 4.

3.10.5.2 The Remaining Proposed SCADA Installations Carry Significant Risk And Are Necessary

TURN continues to argue in its Opening Brief that the GD SCADA Visibility program is addressing relatively lower risk assets compared to those it targeted in the early years of the program.[1308] However, PG&E is forecasting a total of 68 "high" priority and 199 "medium" priority SCADA installations on the GD system out of the remaining 297 planned RTU locations. Only a fraction (approximately 10 percent, or 30 locations) of the remaining forecast SCADA installations on the GD system are classified as "low risk."[1309] Much of the work that remains is necessary to provide complete visibility to many of the larger HISs and complete SCADA equipment installations on smaller and single station HISs to effectively monitor these systems.[1310]

Furthermore, risk scoring is just one method to identify and prioritize locations on the GD system where SCADA should be installed. As discussed previously, the goal of PG&E's SCADA program is to provide 100 percent visibility into the GD system and provide enhanced predictive tools. This goal cannot be accomplished without continuing the installation of SCADA at the remaining 297 locations forecast in this GRC.[1311]

1308 TURN Amended Opening Brief, p. 321.

1309 PG&E-16-E, p. 11-30, lines 1-8; PG&E-16-E, PG&E's response to Data Request TURN_208-Q001, dated 5/24/22, p. AppA-381.

1310 PG&E-16-E, p. 11-29, lines 21-24.

1311 PG&E-16-E, p. 11-30, lines 11-15.

3.10.5.3 PG&E's Past Performance Is Consistent With The Goal Of Completing The GD SCADA Program By 2025.

TURN claims that PG&E has performed less work than authorized in past rate cases and therefore PG&E itself has recognized that GT SCADA "warrants low priority."[1312] However, no such implication can be drawn from PG&E's past execution of this program. First with respect to the 2017-2019 period, for work authorized in the 2017 GRC, while PG&E performed fewer units than imputed for the reasons set forth in PG&E's 2020 GRC testimony, this issue was resolved in the 2020 GRC settlement without any reduction or finding of deferred work.[1313] Second, with respect to PG&E's performance in the 2020-2022 GRC period, PG&E expects to complete all but 36 out of 366 RTU installations authorized in the 2020 GRC.[1314] Of these delayed units all but 13 were the result of COVID-19 delays:

> There are two primary drivers for not being able to complete the additional units: (1) construction and work execution delays incurred as a result of COVID-19 work standdowns to ensure there was proper safety protocol in place for field construction activities (23 planned units impacted in 2020); and (2) reallocation of funding from the RTU SCADA Program to PG&E's higher risk GD Over-Pressure Enhancements Program (MAT 50N) to offset higher costs in that program (13 units affected).[1315] In neither case was system reliability or safety reduced by not performing these units, and in the case of reallocating funding to MAT 50N, safety and reliability was enhanced.[1316]

This reallocation of resources for the 13 units not impacted by COVID-19 delays is in alignment with the Commission's expectation that during a rate case cycle a utility should adjust budgets and reprioritize spending to manage its operations in a safe and reliable manner.[1317] No party,

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1312 TURN Amended Opening Brief, p. 324.

1313 2020 GRC Settlement Agreement adopted in the final decision, D.20-12-005, Section 2.2.4, "resolves the issues TURN raised regarding Gas Distribution SCADA" without any disallowance or reductions.

1314 PG&E-03, p. 11-76, Table 11-20, line 2.

1315 See PG&E-03, Ch. 6 for a description of PG&E's OP Protection Enhancements program (MAT 50N).

1316 PG&E-03, p. 11-76, line 3-13.

1317 D.11-05-018, p. 27.

including TURN, argued that PG&E's actions in executing the GD SCADA program in the 2020-2022 period were imprudent or improper, or sought any deferred work disallowance.

3.10.6 Gas Transmission SCADA Visibility Program – Capital (MAT 76M)

The goal of the GT SCADA Visibility program is to install SCADA at all transmission regulating stations and compressor stations to enable a high degree of monitoring and control for the GTCC.[1318] 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. In this GRC, PG&E's forecast requests $2.8 million of 2023 capital expense funding to install a total of 32 additional SCADA sites (eight per year) on Local Transmission (LT) stations between 2023-2026, bringing LT regulator station visibility from 60 percent at the end of 2022 to approximately 69 percent by 2026.[1319]

TURN proposes to cancel the GT SCADA visibility program completely and provide no further funding. TURN claims that the RSE for this program "shows that the value of the risk reduction from PG&E's proposed work would be minimal compared to the program's costs."[1320] TURN provides no other basis for cancelling the program.

PG&E addressed TURN's proposed cancellation of the GT SCADA program in its Prepared Testimony.[1321] PG&E responds below to further arguments advanced by TURN in its Opening Brief.[1322]

1318 See generally, PG&E Opening Brief, p. 319.

1319 PG&E-16-E, p. 11-33, lines 1-11.

1320 TURN-02, p. 127, lines 1-3.

1321 PG&E Opening Brief, pp. 319-322, Section 3.10.6.

1322 TURN Amended Opening Brief, pp. 318-327, Section 3.10.1.

3.10.6.1 The SCADA Visibility Program Is Justified And Reasonable And Should Not Be Cancelled Based On RSE Scores

PG&E provided testimony discussing the operational and regulatory drivers justifying this program.[1323] No party, including TURN, addressed this testimony.

PG&E's GT SCADA Visibility program (1) provides the GTCC the situational awareness to identify conditions that may lead to abnormal events, diagnostic capabilities to determine 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;[1324] (2) provides the GTCC the ability to implement a predictive approach to operating the system;[1325] and (3) supports and enhances compliance with state and federal regulations as described in Section 3.10.5.1 of this brief for the GD SCADA program.[1326]

PG&E's goal of the Transmission SCADA Visibility program is to install SCADA at all transmission regulating stations and compressor stations. Since 2018, PG&E has at least one SCADA device at each backbone station that along with PG&E's Online Pipeline Simulator provides 100 percent visibility to the backbone system. By the end of 2022, PG&E estimates it will have 60 percent visibility into the LT system. New SCADA points are identified on an ongoing basis as system dynamics change and new risks are identified. PG&E's gas system is not static. The GT SCADA Visibility program provides funding for those additional points identified by operations as being needed to provide key visibility into the GT system.[1327]

Similar to the GD SCADA visibility program, TURN did not address in testimony the operational justifications for the GT SCADA program. In particular, TURN does not address

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1323 PG&E-03, p. 11-57, line 23 to p. 11-60, line 15; PG&E-16-E, p. 11-31, line 18 to p. 11-35, line 30.

1324 PG&E 16-E, p. 11-33, lines 19-24.

1325 PG&E-16-E, p. 11-33, line 25-26.

1326 PG&E Opening Brief, p. 320; PG&E-16-E, p. 11-34, lines 3-12.

1327 PG&E-16-E, p. 11-34, lines 13-23.

PG&E's operational drivers and justifications for continuing to install additional SCADA devices on the LT system,[1328] implying that TURN does not believe full visibility into the LT system is necessary.

Instead, relying on a witness with no experience related to gas operations,[1329] TURN cites the relatively low RSE score for this program as the sole reason for cancelling the program.[1330] Using RSE scores in this way is not appropriate as explained in PG&E's Opening Brief Sections 2.3 and 3.2.2.[1331] While TURN faults PG&E for not explaining adequately, in TURN's view, how RSE scores were considered in its forecast for the GT SCADA program,[1332] by relying solely on the RSE score, TURN ignores the S-MAP Settlement Agreement[1333] that states RSEs are not meant to be the sole determining factor regarding whether risk control or risk mitigation programs should be selected for funding.

In its Opening Brief, TURN advances the following further arguments.

First, TURN's position in this case appears to be that RSE scores nullify all other justifications and reasons given by PG&E for these programs and overrides the opinions of

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1328 PG&E-03, p. 11-57, line 22 to p. 11-59, line 3.

1329 PG&E Opening Brief, pp. 318-319, "TURN witness Lesser . . . has not worked as an employee of a natural gas transmission or distribution utility; is not an expert on PHMSA regulations; and has no experience working on any committee of the AGA. In contrast, Mr. Menegus was the Senior Director of GSO whose responsibilities include: Gas Control and Gas Emergency Response, Gas System Hydraulic Planning, Gas Transmission Project Engineering and oversight of various engineering and support organizations, computerized systems, and technologies that enable the GSO function to be performed. Mr. Menegus . . .has 36 years of experience in engineering design of gas pipeline and station facilities; project management; system operations; operations and maintenance engineering; strategic planning; quality assurance; and developing new gas technologies. He has served as chair of the AGA Task Group on Automated Valves and served on the Interstate Natural Gas Association of America Task Force on Emergency Preparedness and Response."

1330 TURN-02, p. 126, lines 6-8.

1331 PG&E Opening Brief, p. 318.

1332 TURN Amended Opening Brief, p. 323.

1333 D.18-12-014, Attachment A, Appendix A, p. A-14, No. 26.

PG&E's experts. TURN calls PG&E's program drivers "qualitative arguments" contrary to the Commission's multi-year efforts to inform the record with quantitative RSE analysis that allows prioritization of risk reduction proposals.[1334] The mere existence of RSE scores, however, does not mean that the Commission should ignore drivers such as the need to obtain operational visibility into the LT System, and the need for predictive tools to manage the system safely. RSE scores should also not be used to dismiss the judgment of highly experienced experts such a PG&E's witness who are responsible for the safety of PG&E's system, especially when TURN has not provided expert testimony by an expert qualified in gas system operations.

Second, TURN down-plays the relevance of state and federal regulations that requiring the installation of monitoring systems on PG&E's gas pipeline system.[1335] As explained in Section 3.10.5.1 above for the GD SCADA program, however, while PG&E's program goes beyond the minimum requirements of federal and state regulations its approach is consistent with the intent of the regulations, and state law that encourages operators to exceed minimum requirements and apply best practices.[1336]

Third, TURN argues that the GT SCADA program is classified by PG&E as a Type 4 "risk reduction" program, meaning PG&E views the prgram as discretionary.[1337] While under PG&E's Risk Based Portfolio Prioritization Framework the GD SCADA program is categorized as Work Type 4, which includes "discretionary" risk reduction initiatives, Subject Matter Expert input and judgment regarding the operational need for programs are a critical part of the

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1334 TURN Amended Opening Brief, p. 324.

1335 TURN Amended Opening Brief, pp. 325-326.

1336 California Public Utilities Code Section 961(b), (c) and (d): "Each gas corporation shall develop a plan for the safe and reliable operation of its commission-regulated gas pipeline facility" that "shall be consistent with best practices in the gas industry" and "[m]eet or exceed the minimum standards for safe design, construction, installation, operation, and maintenance of gas transmission and distribution facilities prescribed by regulations."

1337 TURN Amended Opening Brief, p. 320, and fn. 937.

prioritization process.[1338] In other words, Type 4 work can nevertheless be required based on the judgment of the managers and experts responsible for the safety of the assets. As PG&E's expert Dan Menegus the Senior Director of GSO responsible for Gas Control and Gas Emergency Response, Gas System Hydraulic Planning, and Gas Transmission Project Engineering testified:

> In my professional judgment, the PG&E's GT SCADA Visibility program is central to PG&E's obligations to put safety at the forefront of our operations and is consistent with state and federal regulation to identify and mitigate risk of abnormal operating conditions. SCADA is the chief tool used by the GTCC to ensure safe GT system operations. SCADA visibility provides the GTCC the situational awareness to more effectively identify conditions that may lead to abnormal events, diagnostic capabilities to determine 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. In addition, PG&E's GT SCADA program provides the GTCC the ability to implement a predictive approach to operating the system. As PG&E explained in its opening testimony, the GT SCADA program is the most effective method to safely and reliably monitor the GT system, allowing GTCC personnel to investigate potential abnormal conditions before they escalate into emergencies, and to dispatch field personnel in an efficient and effective manner, rather than relying on notifications from the public or emergency response personnel before actions can be initiated.[1339]

For these operational and risk related reasons, the GT SCADA program is necessary, consistent with PG&E's designation of the work as Work Type 4.

Finally, TURN claims that "PG&E admitted that its RSE analysis provides the best assessment of the reduction in frequency risk events and risk reduction that would result from PG&E's proposals."[1340] PG&E addresses this claim in Section 3.2.5 of this Reply Brief.

3.10.6.2 Visibility Into Local Transmission Conditions Is Critical

TURN claims in testimony and in its Opening Brief that PG&E has been prioritizing the highest risk parts of its GT SCADA system, and the remaining locations to be addressed in this

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1338 PG&E-16-E, p. 6-21, fn. 29 and PG&E-03, p. 2-22, lines 16-18.

1339 PG&E-16-E, p. 11-33, line 15 to p. 11-34, line 2.

1340 TURN Amended Opening Brief, p, 325.

rate case period pose relatively lower risk.[1341] This argument misses the key reason for achieving a high degree of SCADA visibility: abnormal conditions that cause incidents can occur anywhere on the system. High visibility allows quicker detection and quicker response thereby greatly increasing safety.[1342]

PG&E believes having 100 percent visibility into the local transmission system is necessary to support safe operations and enable the GTCC to actively monitor all parts of the GT system. Currently, PG&E has completed SCADA installations on the backbone transmission system and at other key monitoring locations to support the OPS and to reduce the span of MAOP visibility between backbone monitoring locations and local transmission stations. While PG&E has targeted the most impactful locations on the transmission system first, visibility is needed at all local transmission stations to identify and respond to abnormal operating conditions that may impact downstream distribution systems.[1343]

3.10.7 Gas Transmission Capacity For Load Growth – Capital (MAT 73A)

Capacity Projects install GT 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. The 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.[1344] PG&E forecast $8.6 million in capacity expenditures for this project in 2023.[1345] To develop the 2023 GRC capacity forecast for MAT 73A, PG&E prepared a program level forecast by utilizing a three-year average of recorded costs (2017-2019), and

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1341 TURN-02, p. 126, lines 9-16; TURN Amended Opening Brief, p. 321.

1342 PG&E Opening Brief, p. 321, Section 3.10.6.2.

1343 PG&E-16-E, p. 11-35, lines 8-19.

1344 PG&E Opening Brief, p. 322.

1345 PG&E Opening Brief, p. 323, Table 3-64.

dividing that forecast by 50 percent, escalated. The 50 percent reduction represents the level of uncertainty that PG&E has in projects being identified during the 2023 GRC period and is reflective of the cost necessary to build capacity on an as-identified basis.[1346]

TURN forecasts $6 million, a reduction of $2.6 million to PG&E's forecast.[1347] TURN agrees with PG&E's 50% reduction to the historical average for the 2023 test year forecast for MAT 73A.[1348] TURN, however, disagrees with PG&E's use of a 2017-2019 historical average instead of the three most recent years, 2018-2020.[1349] TURN also asserts that PG&E "could avoid the need for additional transmission [capacity] entirely in the near future"[1350] based on extrapolating PG&E's success in leveraging the use of alternatives to capacity expansion using peak-shaving and use of liquified natural gas (LNG) and compressed natural gas (CNG) support to address all instances of future transmission capacity demand growth.[1351]

PG&E addressed TURN's recommendations and arguments in its Opening Testimony.[1352] PG&E responds below to further arguments advanced by TURN in its Opening Brief.[1353]

3.10.7.1 PG&E's Forecast Is Reasonable

In its Opening Brief, PG&E explained that "PG&E prepared its 2023 forecast for MAT 73A at the end of 2020 in preparation for filing this GRC. Therefore, PG&E used the previous

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1346 PG&E Opening Brief, p. 321.

1347 TURN Amended Opening Brief, p. 314.

1348 TURN Amended Opening Brief, p. 313.

1349 TURN Amended Opening Brief, p. 314.

1350 TURN-07, p. 48, lines 4-6.

1351 PG&E-16-E, p. 11-37, lines 19-25.

1352 PG&E Opening Brief, pp. 322-326, Section 3.10.6.

1353 TURN Amended Opening Brief, pp. 313-318, Section 3.10.1.

three-years of available recorded data to inform the forecast (2017-2019)."[1354] This was the reason that PG&E used the 2017-2019 average cost as a basis for its forecast, not the 2018-2020 average recommended by TURN.

Since the forecast was developed and filed in June 2021, however, PG&E has identified four transmission capacity projects required to meet forecast load growth for the 2023-2026 period.[1355] Current project estimates are between $30 million and $55 million.[1356] PG&E's 2023-2026 forecast for MAT 73A is $34.6 million, representative of the low-end of potential project costs that PG&E may incur. If PG&E was to use a three-year average of 2018-2020 recorded costs, the 2023-2026 forecast would be approximately $25.5 million. In this scenario, PG&E would be significantly underfunded to perform identified capacity investments that maintain uninterrupted service to customers.[1357] The Commission should therefore adopt PG&E's forecast for MAT 73A.[1358]

In its Opening Brief, TURN argues that the four transmission capacity projects "required to meet forecast load growth" identified by PG&E in its rebuttal testimony are speculative and inadequately supported.[1359] First TURN claims that PG&E provides no showing in support of its new assertion that these four projects are required. However, in October 2021, PG&E provided detailed information regarding these projects, and the drivers for each in a data

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1354 PG&E Opening Brief p. 324; PG&E-16-E, p. 11-38, lines 9-11.

1355 PG&E-16-E, PG&E's response to Data Request TURN_041-Q06, dated 10/28/21 and attachment TURN_041-Q06Atch01, pp. AppA-375 to AppA-377.

1356 *Id*.

1357 PG&E-16-E, p. 11-39, lines 17-25.

1358 PG&E Opening Brief, p. 324.

1359 TURN Amended Opening Brief, p. 316.

response.[1360] PG&E provided a summary of the capacity reinforcement projects that were at that time in early stage of planning:

TABLE 3-11
2023 General Rate Case - Planned Capacity Projects for MAT 73A

Order Number	Project (PMO) ID	Planned Year	Project Name	Line (L)	Planned Project Scope	Current Pipeline Diameter	Planned Pipeline Diameter	Business Driver	Estimated Cost
74036588	R-1569	2023	Soscol DFM Reinforcement	DFM-0406-03	Replace approximately 0.75 miles of 4" pipe with 8" pipe.	4"	8"	Capacity replacement of approximately 0.75 miles of 4" pipe with 8" pipe in Napa County to support new residential and commercial demand.	$5 - $10M
TBD	TBD	2023+	Dougherty Valley (Blackhawk DFM) Reinforcement	DFM-2408-11	Replace approximately 1 to 1.8 miles of 6" pipe with 12" pipe.	6"	12"	Eliminates current pipeline capacity constraint for the Camino Tassajara and Dougherty Ranch communities by upsizing the 6" pipeline to 12". The project will also reduce the operating pressure requirements for the L-131 (Bay Area Loop) system allowing for more operational flexibility and system reliability. The upsizing of pipe from 6" to 12" will also remove in-line inspection pigging constraints on DFM-2408-11.	$10-$20M
TBD	TBD	2023+	L-172D New Business Reinforcement	L-172D	Install approximately 6,000ft. of 8" pipe parallel to L-172D which is currently a 6" pipeline.	6"	8"	New Business capacity reinforcement project for an agricultural customer to meet incremental demand increases of 500 thousand cubic feed per hour (Mcfh) of gas demand.	$5M
TBD	TBD	2023+	SF Peninsula High-Risk Winter Operation Elimination	L-101 & L-147	Install one regulator station on the L-101 and L-147 system and perform additional reinforcement activities.	24"	24"	Project will eliminate the need to perform high risk manual operations (valve throttling) during peak winter demand, by isolating the L-101 and L-147 subsystems.	$10-$20 M

The table shows for each planned project its location and scope, business driver, and estimated cost. As PG&E stated, these projects were in early stages of planning.

In the eight months between receiving this data response and filing its opening testimony, TURN requested no further information on these projects. TURN did not address these four projects in its opening testimony despite receiving the information about the projects in October 2021.[1361] Under these circumstances, it is not appropriate for TURN to now claim that PG&E has not provided sufficient detail regarding these projects. TURN also claims that PG&E did not demonstrate that PG&E considered alternatives to these new planned capacity projects.[1362] As PG&E testified, however, "[p]rior to the start of any capacity project, PG&E's GSP department evaluates the forecast capacity demand and identifies whether the system hydraulics can be

1360 PG&E-16-E, p. AppA-375, PG&E's response to Data Request TURN_041-Q06, dated 10/28/2021 and attachment TURN_041-Q06Atch01.

1361 TURN-07, p. 45, line 20 to p. 48, line 21.

1362 TURN Amended Opening Brief, p. 317.

manipulated to meet demand through cheaper alternatives. In many cases, a permanent capacity project is the recommended option due to reliability or safety concerns."[1363] Thus, TURN's speculation that PG&E did not consider alternatives to the four projects is unfounded.

The record contains a reasonable showing for the need, scope, and costs of the four new projects identified by PG&E. This evidence was not addressed or countered by TURN, nor did TURN seek additional detail on these projects. Accordingly, the Commission should adopt PG&E's forecast for MAT 73A in light of these anticipated capacity additions.

3.10.7.2 PG&E Cannot Ignore The Need For Additional Capacity Projects

TURN also asserts that PG&E "could avoid the need for additional transmission [capacity] entirely in the near future"[1364] based on extrapolating PG&E's success in leveraging the use of alternatives to capacity expansion using peak-shaving and use of LNG and CNG support to address all instances of future transmission capacity demand growth.[1365]

PG&E provided a comprehensive response to this claim in its Opening Brief.[1366] In summary TURN overstates PG&E's ability to avoid new capacity. In some instances, PG&E is able to leverage alternative measures to capacity expansion, such as the use of "peak-shaving" and distribution load shifting, and manual field operations.[1367] However, for many of the identified areas that require capacity reinforcements, peak-shaving and distribution load shifting are not viable options to meet forecast customer demand.[1368] Furthermore, despite the move

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1363 PG&E-16-E, p. 11-40 line 29 to 11-41, line 3.

1364 TURN-07, p. 48, lines 4-6.

1365 PG&E-16-E, p. 11-37, lines 19-25.

1366 PG&E Opening Brief, pp. 325-326.

1367 PG&E provided examples in PG&E-16-E, PG&E's response to Data Request TURN_003-Q05, dated 8/27/21, pp. AppA-378 to AppA-379.

1368 PG&E-16-E, p. 11-40, lines 7-19.

toward decarbonization PG&E continues to see load growth occur in a number of areas not currently affected by policies restricting gas usage.[1369]

3.11 Gas Technology

No party raised any issues regarding the Gas Technology program,[1370] nor recommended any reductions to PG&E's forecasts.

3.12 Other Gas Operations Support[1371]

PG&E's Other Gas Operations Support expense and capital forecasts enable Gas Operations to: comply with laws and regulations to protect the environment; qualify the workforce; maintain accurate maps and records of assets; provide services to noncore gas customers; equip employees with the tools and equipment they need to do their jobs safely and efficiently; and build and support the Gas Operations workforce. In this section of our Reply Brief, we address issues regarding our Other Gas Operations Support program forecasts raised by parties in their Opening Briefs:

TABLE 3-12
OTHER GAS OPERATIONS SUPPORT DISPUTED ISSUES

Section	Disputed Program	Party
3.12.1	Butte Rebuild	TURN, Cal Advocates
3.12.2	CEMA Straight Time Labor Program	TURN, Cal Advocates
3.12.3	Gas R&D and Deployment	TURN, Cal Advocates
3.12.4	Other Gas Operations Support	TURN, Cal Advocates
3.12.5	StanPac	TURN
3.12.6	StanPac	TURN

1369 PG&E-16-E, p. 11-41, lines 7-15.

1370 PG&E-03, Chapter 12, pp. 12-1 to 12-17.

1371 Other Gas Operations Support is addressed in Chapter 13 of PG&E's Prepared Testimony, PG&E-03, and further addressed in Chapter 13 of PG&E's Rebuttal Testimony, PG&E-16-E.

3.12.1 Butte Rebuild – Capital And Expense (MAT LXA And MAT 3QA)

These MAT codes are intended for catastrophic events, and activities include gas restoration and rebuild efforts attributed to major events, in declared counties, made by an official authority – either the US President or the Governor of California.[1372] The Community Rebuild Program is also discussed in detail in Exhibit PG&E-04, Chapter 23. The Community Rebuild Program reflects forecast expenses (MAT LXA) and capital expenditures (MAT 3QA) associated with replacing PG&E's infrastructure for the Town of Paradise.[1373] Cal Advocates recommends no funding for this program, and also recommends the removal of all costs for years 2019-2020.[1374] TURN recommends disallowing "rate recovery of any and all costs of PG&E's continuing efforts to repair facilities and restore service in areas impacted by the Camp Fire… ."[1375]

PG&E disagrees with Cal Advocates and TURN's recommendations and addressed this issue in Section 4.23 of its Opening Brief. PG&E further addresses this issue in Section 4.23 of this Reply Brief.

3.12.2 CEMA Straight Time Labor Program – Expense And Capital (MAT 21# And AB #)

PG&E requests recovery of straight time labor associated with Catastrophic Event Memorandum Account (CEMA) eligible activities as these costs are incremental to base rates because the GRC and GT&S forecasts are reduced commensurate with the cost of CEMA activities. Exhibit PG&E-04, Chapter 6, provides further details around the CEMA straight time labor request. PG&E's CEMA straight time labor request for Gas Operations is forecast in MAT 21# for capital and MAT AB# for expense.[1376]

1372 PG&E-16-E, p. 13-9, lines 20-24.

1373 PG&E-04, Ch. 23.

1374 CALPA-05, p. 5, lines 8-13.

1375 TURN-13, p. 1, lines 8-11.

1376 PG&E-16-E, p. 13-11, lines 9-15.

TURN concludes that the cost of employee straight time typically included in PG&E's CEMA applications, as in previous applications, is not an incremental CEMA cost. Those labor hours are already included in existing rates.[1377] TURN recommends that the Commission deny PG&E's request for a separate straight time balancing account to be included in the GRC proceeding. Any further consideration of reimbursing employee straight time costs for a CEMA claim should take place in a CEMA proceeding, not the GRC.[1378]

Cal Advocates proposes 2021-2023 capital reductions to MAT 21# of $2.0 million, $2.0 million and $2.1 million, respectively. Cal Advocates does not address the expense forecast for CEMA straight time labor in MAT AB#.[1379] PG&E disagrees with Cal Advocates' and TURN's recommendations.

PG&E disagrees with Cal Advocates and TURN's recommendations regarding straight time labor costs and addressed this issue in Section 4.6.3 of its Opening Brief. PG&E further addresses this issue in Section 4.6.4 of this Reply Brief.

3.12.3 Gas R&D And Deployment – Expense (MAT GZA)

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.[1380] This program is further described in PG&E's Opening Brief.[1381] PG&E's 2023 expense forecast is $11.5 million ($5.9 million GD and $5.6 million GT). Cal Advocates proposes a reduction of $5.2 million ($2.3

1377 TURN-12, p. 1, line 9.

1378 TURN-12, p. 3, lines 11-14.

1379 CALPA-03, p. 18, lines 9-18.

1380 PG&E-03, p. 13-19, lines 6-9.

1381 PG&E Opening Brief, pp. 334-336, Section 3.12.3.

million GD and $2.9 million GT). TURN proposes a reduction of $4.1 million ($2.0 million GD and $2.1 million GT).[1382]

PG&E addressed Cal Advocates' and TURN's arguments in its Opening Brief. PG&E disagrees with Cal Advocates' recommendation because PG&E's forecast R&D growth will aid in its efforts to expand beyond the traditional consortia, allow the utility to support the advancement and deployment of new technologies, and optimize innovation especially in the context of decarbonization.[1383]

TURN recommends that PG&E's Contributions to Collaborations and Consortiums "Other" category should be held to the last recorded year level of $1,777,248.[1384] However, as explained above, PG&E forecasts to continue to grow its R&D efforts beyond the traditional industry consortia. This investment includes support for deployment of new technologies within its operations to ensure that their benefits are rapidly captured. It will also include broader collaborations to accelerate and optimize the sourcing of innovation especially in the context of decarbonization.[1385]

In their Opening Briefs, Cal Advocates[1386] and TURN[1387] reiterate their arguments that PG&E has not adequately supported its requested increase for the R&D program. However, PG&E provided documentation in support of its request.[1388]

Accordingly, the Commission should adopt PG&E's full forecast for MAT GZA.

1382 PG&E Opening Brief, p. 335, Table 3-68.

1383 PG&E Opening Brief, p. 335.

1384 TURN-05, pp. 13-14.

1385 PG&E-3-E, WP 13-10, Workpaper Table 13-10.

1386 Cal Advocates Opening Brief, pp. 113-114, Section 3.12.1.

1387 TURN Amended Opening Brief, pp. 328-329, Section 3.12.2.

1388 PG&E-16-E, p. AppA-385, CalAdvocates_67-Q.06.

3.12.4 Other Gas Operations Support (MAT AB#)

The expense MAT AB# comprises general support expenses for both Gas Distribution and GT&S related to various programs: Engineer Rotation Development Program (ERDP); Gas Consulting Contracts; GO Data Management; and Gas Asset Strategy's Alternative Energy Program.[1389] In addition, as discussed in Section 3.12.2 above, PG&E's expense forecast for CEMA straight time labor is also included in MAT AB#. TURN's and Cal Advocates' recommended disallowances for CEMA straight time labor in MAT AB# are addressed in that section.

For the distribution portion of MAT AB#, PG&E's 2023 forecast is $16.4 million.[1390] For the GT&S portion of MAT AB# PG&E's 2023 forecast is $18.0 million.[1391] TURN is the only party that addresses this program and proposes a 2023 expense increase of $1.3 million[1392] to PG&E's total MAT AB# forecast of $34.4 million, for the Alternative Energy Program.

PG&E agrees with TURN's proposal to increase the Alternative Energy Program funding.[1393] The Commission should adopt that increase.

PG&E does not agree, however, with the detailed reporting on the Alternative Energy Program recommended by TURN as this program is still immature.[1394] If the Commission believes reporting may be useful now or in the future, 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.[1395]

1389 PG&E-03, p. 13-29, line 22 to p. 13-30, line 27.

1390 PG&E-16-E, p. 13-3, Table 13-1, line 1.

1391 PG&E-3-ES, p. iv.

1392 TURN's recommended increase is split equally between GD and GT&S MAT AB#.

1393 PG&E Opening Brief, p. 337.

1394 PG&E Opening Brief, p. 337.

1395 PG&E-16-E, p. 13-16, lines 19-27.

In its Opening Brief, TURN continues to advocate for its detailed reporting requirements for the Alternative Energy Program.[1396] PG&E is not recommending that the Commission "forego the opportunity to gather information through PG&E's implementation of the Alternative Energy Program that can inform the coordination of building electrification efforts with gas system planning" as TURN implies. PG&E does not object to the potential need for reporting. What PG&E objects to is the adoption without further stakeholder input and discussion of the long list of detailed and elaborate reporting requirements proposed by TURN. TURN's requirements are listed in its Opening Brief and take a page and a half of single-spaced text.[1397] PG&E suggests that a workshop hosted by Commission Staff would be a more appropriate way to define reporting requirements if reporting is deemed desirable by the Commission.

3.12.5 StanPac -- Expense (MAT 34A)

The StanPac pipeline runs from Rio Vista to Richmond, and the entity is 6/7 owned by PG&E and 1/7 by Chevron.[1398] PG&E operates and maintains the StanPac transmission pipeline. The MATs for StanPac are MAT 34A for expense and MAT 44A for capital.[1399] MAT 34A is addressed in this Section 3.12.5 and MAT 44A is addressed in Section 3.12.6 below.

StanPac expense (MAT 34A) covers 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 include project-specific adders related to programs in the Transmission Pipe Asset Family.[1400]

1396 TURN Amended Opening Brief, pp. 330-333.

1397 TURN Amended Opening Brief, p. 333.

1398 PG&E Opening Brief, p. 337.

1399 PG&E-03, p. 13-10, line 27 to p. 13-11, line 12.

1400 PG&E Opening Brief, p. 338.

TURN makes no recommendation on the three-year average component of the MAT 34A forecast. However, as described in the rebuttal testimony of PG&E witness Barnes,[1401] TURN makes recommendations associated with the adder projects for the following Transmission Pipe Asset Family programs: Traditional ILI ($0.3 million reduction); ICDA ($0.1 million reduction); and Strength Testing ($0.1 million reduction).[1402]

PG&E addresses TURN's recommendation in is Opening Brief.[1403] PG&E disagrees with TURN's recommendation, as these StanPac project forecasts are based on the relevant Transmission Pipe Asset Family program cost calculators.[1404]

3.12.6 StanPac -- Capital (MAT 44A)

StanPac capital covers any gas capital project on a StanPac line.[1405] 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 adders related to programs in the Transmission Pipe Asset Family.[1406]

TURN makes no recommendation on the three-year average component of the MAT 44A forecast. However, TURN makes recommendations associated with the adder projects described in the rebuttal testimony of PG&E Witness Barnes[1407] for the Transmission Pipe Asset Family Strength Testing and ILI Upgrade programs.

1401 PG&E-16-E, p. 5-78, lines 1-24.

1402 PG&E-16-E, p. 13-17, lines 21-27.

1403 PG&E Opening Brief, pp. 337-338, Section 3.12.5.

1404 PG&E-16-E, p. 5-78, lines 5-24.

1405 PG&E Opening Brief, pp. 338-339, Section 3.12.6.

1406 PG&E-3-ES, WP 13-48, Workpaper Table 13-25 Revised.

1407 PG&E-16-E, p. 5-78, lines 1-24.

PG&E addresses TURN's recommendation in is Opening Brief.[1408] PG&E disagrees with TURN's recommendation., as these StanPac project forecasts are based on the relevant Transmission Pipe Asset Family program cost calculators.[1409] The rebuttal testimony of Mr. Barnes in Exhibit PG&E-16-E, Chapter 5, describes why PG&E disagrees with the adjustments to both programs.[1410]

3.13 New Business And Work At The Request Of Others[1411]

New Business and Work at the Request of Others includes PG&E's forecast of Gas Operations' expense and capital expenditures for New Business (NB) and Work at the Request of Others (WRO). NB work consists of connecting new customers to PG&E's gas transmission (GT) or gas distribution (GD) systems, and WRO work consists of relocating PG&E's existing GT or GD facilities at the request of governmental agencies, customers, and other third parties. In this section of our Reply Brief, we address issues regarding our NB and WRO Program forecasts raised by parties in their Opening Briefs:

TABLE 3-13
NEW BUSINESS AND WORK AT THE REQUEST OF OTHERS DISPUTED ISSUES

Section	Disputed Program	Party
3.13.1	Gas Transmission Expense Work at the Request of Others	Cal Advocates
3.13.2	Gas Distribution Capital New Business Program	TURN
3.13.3	Gas Transmission (GT) New Business (NB) Program	TURN
3.13.4	Gas Transmission Work at the Request of Others Program	TURN

1408 PG&E Opening Brief, pp. 338-339, Section 3.12.6.

1409 PG&E-16-E, p. 5-78, lines 5-24.

1410 PG&E-16-E, p. 13-19, lines 12-19.

1411 New Business and Work at the Request of Others is addressed in Chapter 14 of PG&E's Prepared Testimony, PG&E-03, and Chapter 14 of PG&E's Rebuttal Testimony, PG&E-16-E.

3.13.1 Gas Transmission Expense Work At The Request Of Others – Expense (MAT Code JTA)

PG&E's GT "Work Requested by Others" (WRO) expense 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, road, street, or other facility, and accommodating a project without requiring the re-location of the pipeline.[1412] This work is generally required by City, County, State, or other jurisdictional agencies.[1413]

PG&E forecast $1.1 million in 2023 expense. Cal Advocates recommends a reduction of $619,000 based on comparison to historic spending.[1414] PG&E addressed Cal Advocates' recommendation in its Opening Brief.[1415] In summary, Cal Advocates' proposal to reduce PG&E's forecast is flawed because: (1) Cal Advocates' 6-year 2016-2021 average of yearly expenses[1416] 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 determined that the five-year average from 2015 to 2019 was the most accurate representation of the recorded expense variations that can occur within this program;[1417] and (2) Cal Advocates use of 2021 data is improper. Recorded expenses for 2021 were not available to PG&E when

1412 PG&E Opening Brief, p. 341.

1413 PG&E-03, p. 14-21, line 16 to p. 14-23, line 3.

1414 CALPA-03, p. 20, lines 15–21.

1415 PG&E Opening Brief, pp. 343-344.

1416 CALPA-03, p. 20, line 18.

1417 PG&E-16-E, p. 14-11, lines 5-14.

determining the 2023 forecast prior to filing on June 30, 2021.[1418] The use of 2021 recorded data in this GRC is further discussed in Section 1.5 of PG&E's Opening Brief.

Accordingly, the Commission should adopt PG&E's forecast, and reject Cal Advocates' recommended reduction.

3.13.2 Gas Distribution Capital New Business Program – Capital (MWC 29)

PG&E and TURN have reached a stipulation that settles all forecast issues for MWC 29. The stipulation is attached to this Reply Brief as Appendix C. Specifically, as set forth in Appendix C, PG&E and TURN agree to the following:

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 4-year (2023-2026) 2023 GRC 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) GRC cycle, with any underspending returned to ratepayers. Any spending above the forecast will be reviewed as part of PG&E's 2027 GRC 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 GRC 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 GRC 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 (Exhibit TURN-08, Section III.A).

PG&E requests that the Commission approve the PG&E/TURN stipulation for MWC 29 in its entirely as a full resolution of all MWC 29 issues.

1418 PG&E-16-E, p. 14-11, lines 5-8.

3.13.3 Gas Transmission (GT) New Business (NB) Program – Capital (MAT 26A)

The GT New Business Capital Program[1419] consists of projects that require either significant pressure or new load along with other major projects.[1420] PG&E's forecast for the GT NB program is $7.9 million in the 2023 test year. A five-year historical average (2015 through 2019) of escalated capital expenditures for this program ($2.1 million) was used to determine the forecast for the rate case period. A further $5.8 million has been added to the forecast for anticipated major conversion projects.[1421] The adder was based specifically on PG&E's Large Gas Solutions program that presents solutions to large customers to switch 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.[1422]

In its testimony, TURN recommended that PG&E's $5.8 million of adder projects be removed.[1423]

In its Opening Brief, TURN further revises its recommendation in light of the Commission's issuance of Decision 22-09-026 that eliminated gas allowances for residential and commercial new business projects after July 1, 2023 (the Gas Allowance Decision).[1424] TURN's revised proposal for MAT 26A is as follows:

> First, the Commission should take one of the following steps (or another comparable approach):
>
> > (1) Directing PG&E to submit a Tier 2 compliance advice letter on August 1, 2023, that revises the authorized GRC forecast for GT New Business Capital costs in MAT 26A for 2023-2026 based on applications submitted prior to the July 1, 2023 cutoff, and proposes to credit ratepayers with the difference through the next adjustment in gas rates (and subsequently as

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1419 PG&E Opening Brief, pp. 352-354, Section 3.13.3.

1420 PG&E-03, p. 14-23, line 4 to p. 14-25, line 24.

1421 PG&E-3-ES, WP 14-19, Workpaper Table 14-19; PG&E-16-E, p. 14-18, lines 3-13.

1422 PG&E-03, WP-14-25, Large Gas Solutions Project Summary.

1423 TURN-07, p. 45, lines 12-14.

1424 TURN Amended Opening Brief, p. 346.

> part of the implementation of any authorized post-test year adjustments); or
>
> (2) Reducing PG&E's 2023 forecast for MWC 26A by 50% and directing PG&E to create a new one-way balancing account to track actual expenditures on GT New Business over the four-year GRC period, with any overcollection returned to ratepayers. When viewed over the 2023-2026 GRC cycle, the 50% reduction is very conservative given the tapering off of remaining line extension subsidies over the post-test years.

Second, all costs for Large Gas Solutions Projects (MAT 26B) should be removed from the GRC forecast.[1425]

As explained further below, PG&E disagrees with TURN that a reduction of PG&E's forecast is warranted in light of the Commission's Gas Allowance decision or that the costs of the Large Gas Solutions adder projects should be removed. Accordingly, PG&E recommends that its full 2023 forecast of $7.9 million be adopted without reduction. PG&E does not object to TURN's proposal that PG&E be directed to create a new one-way balancing account to track actual expenditures on GT New Business over the four-year GRC period, with any overcollection returned to ratepayers. PG&E believes that this approach would be reasonable under the circumstances. This approach would also make unnecessary TURN's alternate proposal for an advice letter process after July 1, 2023 to true up the forecast. Finally, the Commission should confirm that funding requirements for any new business projects after July 1, 2023 are not part of the GRC forecast, but that cost recovery of those requirements will be addressed separately under the special post-July 2023 application process adopted in the Gas Allowance Decision.[1426]

3.13.3.1 PG&E's $7.9 million 2023 Forecast Should Be Adopted Without Reduction.

PG&E's $7.9 million 2023 forecast for GT NB (MAT 26A) consist of two parts: (1) $2.1 million representing a five-year historical average (2015 through 2019) of escalated capital

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1425 TURN Amended Opening Brief, p. 347.

1426 D.22-09-026, pp. 81-82, OPs 2 and 3.

expenditures for this program[1427] and (2) $5.8 million for anticipated major conversion projects from PG&E's Large Gas Solutions program.[1428]

As explained further below, PG&E does not believe either of these components of the forecast will be significantly affected by the elimination of gas allowances after July 1, 2023, nor should the Large Gas Solutions projects be removed from the forecast. Accordingly, PG&E recommends that its 2023 forecast of $7.9 million be adopted. PG&E does not object to TURN's proposal that PG&E be directed to create a new one-way balancing account to track actual expenditures on GT New Business over the four-year GRC period, with any overcollection returned to ratepayers.[1429]

First, the $2.1 million historic spend portion of the forecast is expected to be needed to cover projects that are already in flight 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.[1430] GT 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 be incurring costs for GT project allowances related to applications received before July 2023 throughout the 2023-2026 period. An adjustment to PG&E's forecast for MAT 26A is therefore not warranted since PG&E expects to pay allowances over the entire 2023-2026 rate case period. TURN's recommendation to reduce the forecast by 50 percent to reflect the

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1427 PG&E-3-ES, WP 14-19, line 9.

1428 PG&E-3-ES, WP 14-19, line 11.

1429 TURN Amended Opening Brief, p. 347.

1430 PG&E Opening Brief, p. 350, Table 3-74.

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.

Second, the $5.8 million adder is needed for PG&E's Large Gas Solutions program that presents solutions to large customers to switch 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.[1431] In its Opening Brief, PG&E responded to TURN's arguments that the forecasted costs of PG&E's Large Gas Solutions Projects be removed.[1432] The Large Gas Solutions Program creates a higher level of New Business activity than in past rate case periods. In the past, PG&E's GT 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.[1433]

In its testimony, PG&E provided forecasts and examples of the types of new conversion projects included in the Large Gas Solutions program.[1434] These include Cement, Chemical, and Processing Plants, CNG Stations, and Agricultural Farms. Projections were developed using historical project costs and allowances for similar type projects. Some of these new projects also include back up generation for data centers.[1435] Currently there are more than 20 of these types of new projects identified for execution in the rate case period.[1436] Given the number of already-identified programs and the likelihood that as a result of PG&E's proactive outreach

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1431 PG&E-03, WP-14-25, Large Gas Solutions Project Summary.

1432 PG&E Opening Brief, pp. 352-354, Section 3.13.3.

1433 PG&E-16-E, p. 14-19, lines 12-23.

1434 PG&E-03, WP 14-25.

1435 PG&E-16-E, p. 14-19, lines 5-11.

1436 PG&E-16-E, p. 14-19, lines 12-23.

under this program additional projects will materialize before the July 2023 deadline, no reduction to PG&E's adder forecast is warranted.

Accordingly, the Commission should adopt without reduction PG&E's $7.9 million forecast for MAT 26A that includes $2.1 million of historical spending activity and the additional $5.8 million for the Large Gas Solutions program. PG&E does not object to TURN's proposal that PG&E be directed to create a new one-way balancing account to track actual expenditures on GT New Business over the four-year GRC period, with any overcollection returned to ratepayers. PG&E believes that this approach would reasonable under the circumstances and would protect ratepayers against the possibility the payment of gas allowances will be lower than forecast.

3.13.3.2 The Commission Should Reject TURN's Advice Letter Approach

TURN's alternate recommendation is that PG&E be directed to submit a Tier 2 compliance advice letter on August 1, 2023, that revises the authorized GRC forecast for GT New Business Capital costs in MAT 26A for 2023-2026 based on applications submitted prior to the July 1, 2023 cutoff, and proposes to credit ratepayers.[1437] PG&E believes that this approach is not necessary and should be rejected. First, as explained in the section above, given the expectation that for existing and new interconnection projects prior to the July 2023 deadline, allowances and subsidies will likely continue to be paid throughout the forecast period, the Commission should adopt PG&E's $7.9 million forecast without reduction. Second, if the Commission adopts TURN's proposal that PG&E be directed to create a new one-way balancing account to track actual expenditures on GT New Business over the four-year GRC period, with any overcollection returned to ratepayers, ratepayers will receive a credit for any underspending. An advice letter process to "true up" the forecast as TURN recommends would therefore not be necessary.

1437 TURN Amended Opening Brief, p. 347.

If the Commission does adopt TURN's advice letter true-up proposal, the Commission should extend the time for PG&E to prepare and submit the advice letter from 30 days to 90 days. The August 1, 2023 date TURN proposes only provides 30 days, and is much too soon for PG&E to be able to evaluate and estimate the total costs for allowance applications submitted by the July 1 deadline.

3.13.3.3 Funding For New Projects After July 1, 2023 Are Not Part Of The GRC Forecast

D. 22-09-026 eliminated allowances for project applications submitted after July 1, 2023. However, pursuant to the decision, applications for gas line extension subsidies for unique non-residential projects meeting certain criteria set forth in D.22-09-026, may be submitted annually by utilities after July 1, 2023.[1438] The Commission should confirm that funding for projects submitted pursuant to the special post-July 2023 application process will be addressed as part of those applications and are not included in the MWC 26A forecast.

3.13.4 Gas Transmission Work At The Request Of Others Program – Capital (MAT 83A)

The GT WRO 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.[1439]

PG&E's original forecast for the GT WRO Capital Program was $20.9 million in the 2023 test year. 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.[1440] Based on information available at the time, a cost adder of $5.5 million for the Department of

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1438 D.22-09-026, pp. 81-82, OP 2 and 3.

1439 PG&E Opening Brief, p. 354.

1440 PG&E-03, WP 14-20, Workpaper Table 14-20.

Water Resources Delta Conveyance Project (DCP) was also included in the forecast.[1441] Following adjustment for PG&E's concession to TURN's recommended removal of $5.5 million from the 2023 forecast for MAT 83A, the adjusted forecast that PG&E is seeking is $16.0 million.[1442]

In its Opening Brief PG&E agreed to TURN's proposal[1443] and TURN agrees in its Opening Brief that "the issue is no longer in dispute."[1444] Accordingly, the Commission should adopt PG&E's revised forecast for MAT 83A of $16 million in 2023 capital expenditures.

3.14 Ratemaking

3.14.1 Gas Storage Balancing Account (GSBA)

In the 2019 GT&S Rate Case, because of the significant regulatory uncertainty regarding gas storage regulations and requirements and the associated impact this uncertainty could have on costs, the Commission adopted the Gas Storage Balancing Account or "GSBA" as a two-way balancing account.[1445] In this rate case, because this regulatory uncertainty is ongoing, PG&E has proposed continuing the GSBA. TURN is the only party that addresses the GSBA and it agrees with PG&E that the two-way balancing account should be retained.[1446]

In addition to retaining the GSBA, we are also proposing changes to how costs recorded in the GSBA are recovered. Specifically, PG&E is proposing that it would file a Tier 2 advice letter each year after the GSBA recorded costs for the year are final, typically in April. The advice letter would provide details regarding the actual costs incurred as compared to the adopted forecast amount, indicate whether there was an over- or under-collection, and create a

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[1441] PG&E-16-E, p. 14-20, lines 16-23.

[1442] PG&E-3-ES, p. v.

[1443] PG&E Opening Brief, p. 355.

[1444] TURN Amended Opening Brief, p. 348, Section 3.13.3.

[1445] D.19-09-025, pp. 94-95; See also PG&E Opening Brief, p. 257.

[1446] TURN Amended Opening Brief, p. 349.

vehicle for PG&E to either return the overcollection to customers or to recover the under-collection in rates. If a party protests PG&E's Tier 2 advice letter, that party could ask for the Commission Staff or the Commission to convert the Tier 2 advice letter into a Tier 3 advice letter or that PG&E be required to file an Application in lieu of the Tier 2 advice letter.[1447]

TURN opposes PG&E's proposal for an annual advice letter filing, essentially repeating the arguments raised in TURN's testimony.[1448] TURN's arguments were addressed in our Opening Brief.[1449]

3.14.2 Transmission Integrity Management Plan Balancing Account (TIMPBA)

The TIMP Balancing Account or "TIMPBA" is a one-way balancing account that the Commission established in the 2019 GT&S rate case to track TIMP related costs. The TIMPMA was established in the 2015 GT&S rate case and is used to track any TIMP costs that are not included in PG&E's forecast "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."[1450]

In this proceeding, PG&E is proposing to convert the TIMPBA to a two-way balancing account and to eliminate the TIMPMA. Alternatively, if the TIMPBA remains a one-way balancing account, PG&E is proposing to keep the TIMPMA and modify 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 is proposing to structure 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 process. However, for costs greater than 135 percent of the adopted amount, PG&E would record these costs in a separate subaccount and would file a separate application for recovery of

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1447 PG&E Opening Brief, p. 258.

1448 TURN Amended Opening Brief, pp. 349-350.

1449 PG&E Opening Brief, pp. 258-260.

1450 PG&E Opening Brief, p. 176.

these costs. Eliminating the TIMPMA and converting the TIMPBA into a two-way balancing account will reduce the current administrative complexity involved in maintaining a balancing account and a memorandum account and the necessary reviews that are required of these two accounts.[1451]

TURN and Cal Advocates argue that the TIMPBA should remain a one-way balancing account, citing Commission decisions from the 2015 and 2019 GT&S rate cases.[1452] We addressed these arguments in our Opening Brief.[1453]

TURN also asserts that under PG&E's proposal "only an advice letter filing would be required to request cost recovery . . ..."[1454] This is incorrect. The forecast for costs that would be included in the TIMPBA (*i.e.*, TIMP costs related to PG&E's gas transmission) are being <u>requested and reviewed</u> in this proceeding. To the extent the Commission determines PG&E's forecast is reasonable, these costs would then be recovered through the TIMPBA. Thus, the TIMPBA forecast costs are not requested and reviewed only through the advice letter process. If the TIMPBA costs <u>exceed</u> the Commission-adopted amount, PG&E would file a Tier 2 advice letter for the amounts that are up to 35% above the adopted amount and would file an application for amounts that are greater than 35% above the adopted amount. Parties can ask for review of the costs exceeding the adopted amount by protesting the advice letter process and/or application. Thus, parties' ability to review and protest the amounts above the adopted levels is fully preserved. It is undisputed that the Commission has recently approved two-way balancing accounts for wildfire costs that operate the exact same way as PG&E now proposes for the TIMPBA.[1455]

1451 PG&E Opening Brief, p. 176.

1452 TURN Amended Opening Brief, pp. 351-353; Cal Advocates Opening Brief, p. 119.

1453 PG&E Opening Brief, pp. 176-179.

1454 TURN Amended Opening Brief, p. 351.

1455 PG&E-03, p. 5-17, lines 3-11.

Notably, TURN fails to address the inconsistency in its own positions. In a separate proceeding, TURN supported a two-way TIMP balancing account proposal for SDG&E.[1456] Here, TURN takes a completely opposite position. TURN's Opening Brief is noticeably silent on its inconsistent positions.

Cal Advocates does not dispute that there is uncertainty related to TIMP costs as a result of changing regulatory requirements, but argues this uncertainty is addressed through the TIMPMA.[1457] However, costs recorded in the TIMPMA can only be recovered through an after-the-fact application process that requires a substantial amount of time and lag in cost recovery. Converting the TIMPBA into a two-way balancing account allows for recovery of costs associated with this acknowledged regulatory uncertainty in a more efficient and timely manner.[1458] However, as explained above, PG&E's proposal for the two-way TIMPBA still preserves parties' right to protest any costs above the adopted amounts.

Cal Advocates also suggests that the current TIMPBA/TIMPMA structure is more appropriate to address costs associated with regulatory uncertainty.[1459] It is unclear, however, why this is the case. Both the current structure and PG&E's proposal to make the TIMPBA a two-way account and eliminate the TIMPMA address costs associated with regulatory uncertainty. The difference is that PG&E's proposal is more streamlined and efficient for the Commission and parties, rather than having two separate accounts, one of which requires an application for cost recovery.

Cal Advocates attempts to distinguish PG&E's TIMPBA proposal from other two-way balancing accounts adopted by the Commission such as the WMBA.[1460] However, the

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1456 PG&E Opening Brief, pp. 177-178.

1457 Cal Advocates Opening Brief, pp. 117-118.

1458 PG&E-03, p. 5-17, line 23 to p. 5-18, line 2.

1459 Cal Advocates Opening Brief, p. 118.

1460 Cal Advocates Opening Brief, pp. 118-119.

distinction Cal Advocates seeks to create is non-existent. Cal Advocates acknowledges that there is a "high level of uncertainty unique to TIMP-related expenses . . .."[1461] The Commission approved the WMBA for wildfire costs for similar reasons – cost uncertainty.[1462] Thus, there is no basis for Cal Advocates argument that the WMBA is distinguishable from PG&E's proposal here.

Finally, TURN's and Cal Advocates' Opening Briefs do not substantively address PG&E's alternative proposal regarding modifications to the TIMPMA. For the reasons stated in our Opening Brief, if the Commission retains the TIMPBA as a one-way balancing account, PG&E's proposed alternative for the TIMPMA should be adopted.[1463]

3.14.3 Other Balancing And Memorandum Accounts

3.14.3.1 In-Line Inspection Memorandum Account (ILIMA)

The ILIBA and ILIMA were established by the Commission in the 2019 GT&S rate case. The ILIBA records capital costs for the 48 Traditional ILI Upgrade projects adopted for the rate case period. The ILIMA records capital costs incurred for projects completed above the 48 adopted ILI upgrades, the associated initial assessments and DE&R expenses, as well as all reassessment expenses and associated repairs. 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 the 18 ILI Upgrade projects per year that it was forecasting. Thus, the Commission set the authorized number of ILI Upgrades at 12 but provided PG&E to opportunity to do more and record these costs in the ILIMA. In this case, however, PG&E is proposing to perform 12 ILI Upgrades per year, consistent with the Commission's direction, thus there is no need for the ILIBA and ILIMA structure adopted in the 2019 GT&S Rate Case. Because they are no longer needed, PG&E is proposing to eliminate the ILIBA and ILIMA. Costs associated with initial runs, re-assessments

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1461 Cal Advocates Opening Brief, p. 118.

1462 PG&E-03, p. 5-17, lines 3-11, citing D.20-12-005, p. 120.

1463 PG&E Opening Brief, p. 179.

and any associated repairs would be accounted for in the TIMPBA because these costs relate to a TIMP program.[1464]

Cal Advocates argues that the ILIMA and ILIBA should be retained until PG&E "proves" that it has "cured its history of underperformance" in terms of performing ILI work.[1465] Although PG&E does not agree with Cal Advocates' characterization of events, the "proof" Cal Advocates seeks is already in the record. In 2019, PG&E completed 11 ILI Upgrade projects and in 2020, PG&E completed 14 ILI Upgrade projects.[1466] Thus, through the first two years of the rate case, PG&E has actually completed more ILI Upgrades projects than forecast. Cal Advocates' concerns about underperformance for ILI Upgrades are belied by the evidence.

TURN supports eliminating the ILIMA but recommends that the ILIBA be retained.[1467] TURN's argument for retaining the ILIBA is based on PG&E's alleged underperformance. This issue is addressed above with regard to Cal Advocates' position.

3.14.3.2 Internal Corrosion Direct Assessment Memorandum Account (ICDAMA)

The 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. The ICDAMA was adopted in the 2019 GT&S rate case primarily to address concerns that PG&E had not completed ICDA work in the 2015 GT&S rate case period to instead fund more TIMP strength tests. Thus, the Commission established this memorandum account to track ICDA work for 2019 GT&S rate case period (2019-2022).[1468] Because PG&E has completed the ICDA units authorized in the 2019 GT&S rate case, it is proposing to eliminate the ICDAMA.

1464 PG&E Opening Brief, pp. 179-180.

1465 Cal Advocates Opening Brief, p. 123.

1466 TURN-04, Attachment O (listing ILI Upgrade projects completed in 2019 and 2020).

1467 TURN Amended Opening Brief, p. 355.

1468 PG&E Opening Brief, p. 182.

Cal Advocates argues the ICDAMA should be continued for ICDA direct examination costs in MAT HPO because of year-over-year variability in these costs.[1469] This argument is flawed for several reasons. First, the ICDAMA was <u>not</u> established because of cost variability, but because ICDA funds approved in the 2015 GT&S rate case were spent on other TIMP strength tests. In this proceeding, there is no dispute that PG&E has used adopted ICDA funds approved in the 2019 GT&S rate case for ICDA work, <u>not</u> for other programs.[1470] Thus, there is no need for the ICDAMA.

Second, Cal Advocates argues that alleged underspending by PG&E in 2021 (*i.e.*, cost variability) justifies retaining the ICDAMA.[1471] Cal Advocates acknowledges that PG&E spent more than the forecasted amount in 2020, but then asserts that in 2021 PG&E underspent its 2021 forecast.[1472] However, in comparison to the forecasts in the 2019 GT&S rate case, PG&E has actually overspent its forecasts. PG&E's forecast for the two ICDA-related programs (MATs HPJ and HPO) in the 2019 GT&S rate case was approximately $3.7 million per year.[1473] Our actual spend for MATs HPJ and HPO in 2021 was approximately $5.3 million.[1474] Thus, in 2021, PG&E spent <u>more</u> than its 2019 GT&S rate case forecast amount for the ICDA related programs (MATs HPJ and HPO).

Finally, Cal Advocates points to a recent PHMSA interpretation that will increase the number of ICDA digs and correspondingly increase costs and argues that these increased costs

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1469 PG&E Opening Brief, pp. 154-155.

1470 PG&E-16-E, p. 5-47, lines 8-10.

1471 Cal Advocates Opening Brief, pp. 120-121.

1472 Cal Advocates Opening Brief, p. 120.

1473 D.19-09-025, pp. 140-145. The Commission did not ultimately adopt a forecast for ICDA in the 2019 GT&S rate case because it approved the ICDAMA instead.

1474 PG&E-23-E, 10-AtchA-10 (HPJ expense in 2021 was $359,000 and HPO expense was $4.964 million).

justify retaining the ICDAMA.[1475] However, the recent PHMSA interpretation has already been incorporated into PG&E's 2023 forecast and thus there is no need to continue the ICDAMA because of uncertainty associated with this interpretation.[1476]

3.14.3.3 The Internal Corrosion Balancing Account (ICBA)

The 2019 GT&S Final Decision established the one-way Internal Corrosion Balancing Account (ICBA) for capital internal corrosion expenditures recorded in MAT 3K1.[1477] PG&E recommends that the Commission discontinue the ICBA in 2023.[1478] Cal Advocates disagrees with PG&E's recommendation and recommends the Commission continue with the ICBA. Cal Advocates asserts that PG&E has performed below the level adopted by the Commission for the years 2019-November 2021.

PG&E responded to Cal Advocates' arguments in its Opening Brief.[1479] First, PG&E addressed the Commission's stated rationale for the ICBA - that PG&E's 2019 GT&S rate case application did not explain with adequate detail its methodology for calculating its capital forecast - and requests that the ICBA be discontinued at the end of the current rate case period.[1480] Second, while PG&E acknowledges that recorded expenditures for Capital Internal Corrosion Mitigation, MAT 3K1, for the period 2019-November 2021 were below adopted, PG&E anticipates exceeding the number of pipeline drip replacements forecast in the 2019 GT&S.[1481]

1475 Cal Advocates Opening Brief, p. 121; see also PG&E-16-E, p. 5-45, lines 22-27 (explaining new PHMSA interpretation).

1476 PG&E-16-E, p. 5-46, lines 13-15.

1477 D.19-09-025, p. 204.

1478 PG&E-03, p. 9-64, lines 15-27.

1479 PG&E Opening Brief, pp.356-357, Section 3.14.3.2.

1480 PG&E Opening Brief, p. 357.

1481 PG&E-03, WP 9-108, line 1.

In its Opening Brief, Cal Advocates reiterates its arguments and adds that without the continuation of the ICBA "PG&E will lose an incentive to keep costs low and protect ratepayers."[1482] This argument ignores the soundness of PG&E's forecast. PG&E's 2023-2026 capital cost forecast for capital internal corrosion is provided in Exhibit PG&E-03, WP 9-90, and is based on actual pipe replacement data that is utilized across multiple chapters of this application. The complete details of the pipe replacement cost curves are provided in Exhibit PG&E-03, WP 5-109.[1483] Cal Advocates did not take issue with PG&E's 2023 forecasting basis or approach.[1484] Accordingly, the Commission should adopt PG&E's forecast as reasonable and reject Cal Advocates' request to continue the ICBA.

3.14.3.4 New Environmental Regulations Balancing Account (NERBA)

In the 2020 GRC settlement, that was adopted by the Commission in D.20-12-005, the parties agreed to the continuation of NERBA in 2020-2022 (Section 4.1.1.1):

> This balancing account 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 shall be modified and the distribution subaccount will be retained through 2022 for the sole purpose of tracking the costs associated with below ground Grade 3 leak repairs (Best Practice 21).[1485]

PG&E requests continuation of NERBA in the 2023 GRC period to record Below Ground Grade 3 (BG3) leak repairs to ensure that PG&E and ratepayers are protected against the continued uncertainty and potential fluctuation in the number and costs of repairs.[1486] Cal Advocates recommends that "NERBA…be discontinued at the end of 2022."[1487]

1482 Cal Advocates Opening Brief, p. 125.

1483 PG&E Opening Brief, p. 357.

1484 PG&E Opening Brief, p. 289.

1485 2020 GRC Settlement Agreement adopted in the final GRC decision, D.20-12-005, p. 32, Section 4.1.1.1.

1486 PG&E-03, p. 10-52, lines 3-20.

1487 CALPA-02, p. 88, line 8.

In its Opening Brief, PG&E sets forth the justification for continuing the NERBA, and responds to Cal Advocate's arguments.[1488] In summary: (1) Commission Resolution G-3538 created significant uncertainty as to what level of BG3 repairs the Commission would deem to be cost effective;[1489] (2) the biennial leak abatement compliance plan process means that the uncertainty of the appropriate level of BG3 repairs is likely to continue;[1490] and (3) continuing NERBA will not impact PG&E's efficiency and cost effectiveness of doing BG3 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.[1491] [1492]

In its Opening Brief, Cal Advocates continues downplay the very real uncertainty as to what level of BG3 repairs will be approved as reasonable as part of PG&E's biennial leak abatement plans.[1493] Under Best Practice 21 adopted in the Leak Abatement OIR, all leaks must be repaired within three years of discovery, except for leaks that are costly to repair relative to their size.[1494] It is in the biennial leak abatement compliance plan process that the SPD provides guidance on what level of BG3 leaks is cost effective from a leak abatement standpoint. This process creates uncertainty that justifies continuation of the NERBA to protect both ratepayers and PG&E from the constant cycle of reevaluation every two years. PG&E submits that this is an unusual circumstance and BG3 leak repairs are therefore not like other work that is forecast in the GRC as argued by Cal Advocates.[1495]

1488 PG&E Opening Brief, pp. 357-361, Section 3.14.3.3.

1489 PG&E Opening Brief, p. 359.

1490 PG&E Opening Brief, pp. 359-360.

1491 PG&E-16-E-E, p. 10-28, lines 8-10.

1492 PG&E Opening Brief, pp. 360-361.

1493 Cal Advocates Opening Brief, pp. 123-124.

1494 D.17-06-015, p. 159, OP 4 and p. 153, COL 23.

1495 Cal Advocates Opening Brief, p. 124.

For all these reasons and given the uncertainty due to the biennial reevaluation of BG3 leak repair cost effectiveness, a continuation of NERBA is critical to protect ratepayers and PG&E from fluctuations in the SPD-approved level of cost effective BG3 leak repairs.

3.14.3.5 New Account Related To MWC 29: Gas Distribution New Business Balancing Account (GDNBBA)

As described in Section 3.13.2 above (Gas Distribution Capital New Business Program – Capital (MWC 29)) PG&E and TURN have reached a stipulation that settles all forecast issues for MWC 29. The Stipulation is attached to this Reply Brief as Appendix C. PG&E and TURN request that the Commission adopt the Stipulation as a full resolution of all MWC 29 issues. As part of the Stipulation, PG&E and TURN agree that "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)."

4. ELECTRIC DISTRIBUTION (EXHIBIT PG&E-04)

4.1 PG&E Forecast And Overview

4.1.1 PG&E Demonstrated The Reasonableness Of Its GRC Proposals And Forecasts

PG&E is focused on achieving its core mission to deliver affordable and clean energy safely and reliably to our customers. To that end, PG&E's Electric Distribution (ED) expense and capital forecasts represent a risk-informed portfolio that puts safety first while maintaining a reliable electric system and positioning the utility to meet future challenges, including those presented by climate change. PG&E submitted ample evidence demonstrating the reasonableness of the forecasts. In particular, PG&E's testimony (Exhibits PG&E-04 and PG&E-17) explains in detail the scope of activities planned by PG&E and how those activities are vital to maintaining a safe and reliable electric distribution system and addressing wildfire risks effectively.

In their Opening Briefs, Cal Advocates, TURN, and other intervenors oppose significant portions of PG&E's proposed activities and forecasts, with customer affordability as a prominent theme of their opposition. As discussed above in Section 1.3, PG&E understands and is addressing customer-affordability concerns. But one cannot address these concerns at the cost of safety and reliability. To do so would be penny-wise and pound-foolish. PG&E must re-invest in electrical infrastructure to build and maintain a resilient and reliable electrical system and mitigate wildfire risks. This investment promotes customer affordability over the long-term as PG&E is able to reduce certain expenses by deploying more effective permanent solutions.

The risk of wildfire is urgent. This cannot be ignored. The consequences of inaction are potentially catastrophic and must be avoided. PG&E must be adequately funded to address infrastructure needs and climate-driven wildfire risks with bold, forward-thinking initiatives. PG&E respectfully urges the Commission to approve PG&E's ED expense and capital forecasts presented in this GRC so that PG&E can move forward with the important work forecast in this GRC.

4.1.2 Bold Action Is Required To Meaningfully Reduce Wildfire Risk In California

PG&E's proposed 10,000 mile undergrounding program is the type of forward-thinking initiative that the Commission and parties should support. When fully implemented, PG&E's undergrounding program will: (1) result in the near-total elimination of wildfire risk caused by utility assets in the areas undergrounded; (2) improve reliability with reduced customer impacts caused by Public Safety Power Shutoffs (PSPS) and Enhanced Powerline Safety Settings (EPSS) outage events; (3) provide potential for long-term savings when undergrounding is compared to overhead hardening and vegetation management costs; (4) provide long-term resiliency benefits, including reduced weather-related outages and decreased exposure to harsh conditions that degrade or damage overhead facilities; and (5) provide environmental benefits and greater economic certainty (i.e., reduced insurance costs[1496] and greater confidence in business continuity) for communities and businesses in or near HFTDs as well as all of California more broadly.[1497]

4.1.3 Wildfire Mitigation Will Continue To Evolve And Regulatory Review Should Proceed On The GRC Forecast

PG&E's 10,000 mile undergrounding plans will evolve in light of: (1) the ongoing work and learnings from its project management team, engineers, operators, construction workers, and other experts; (2) input from external stakeholders; (3) the undergrounding plan reviews pursuant to Senate Bill (SB) 884; (4) the permitting process under state, county, and local laws; and (5) other factors such as economic and market conditions, and supply chain dynamics.

During his opening remarks at the start of evidentiary hearings, Commissioner Reynolds highlighted, in particular, the timing challenges presented in connection with PG&E's forecasting in this GRC while at the same time submitting annual wildfire mitigation plans

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1496 Tr. Vol. 9, 1625:14-22, PG&E/Martin.

1497 AT&T witness, Dr. Richard Clarke, referred to these benefits as exhibiting the aspect of serving as a public good that benefits both California residents and businesses. Tr. Vol. 13;2576:7 to 2577:20, AT&T/Clarke.

(WMPs) for review by the Office of Energy Infrastructure Safety (OEIS). Commissioner Reynolds noted that in light of this timing, it is reasonable to expect PG&E's plans to evolve and to allow for potential changes in the GRC:

> The Wildfire Mitigation Plan process remains relatively new and we expect PG&E, like other utilities, to continue adjusting its approaches to wildfire mitigation in light of developments and learning in the WMP process.
>
> ****
>
> And in this general rate case, our task, as I see it, is to review the reasonableness of PG&E's forecasted expenses for these four years and, especially to the maximum extent that we can, to harmonize this general rate case with the ongoing work OEIS is doing with PG&E's Wildfire Mitigation Plan.[1498]

As explained further below, a balancing account is an established ratemaking mechanism that can be used to harmonize the GRC forecast with PG&E's undergrounding planning that is certain to evolve given these regulatory dynamics and other factors.

4.1.4 PG&E Presents A Reasonable Outcome To Its Undergrounding Program Forecast To Account For Regulatory Reviews And Intervenors' Concerns Regarding Costs In This GRC period

Recognizing that the factors described above (including the OEIS' regulatory review process) will impact undergrounding plans over many years, PG&E already planned to underground fewer miles in the initial years, ramping up in later years after incorporating regulatory input, lessons learned, and efficiencies gained in initial years.[1499] PG&E plans to sequence the execution of underground miles taking into account risk reduction, executability, and community impact.[1500] In the February 25, 2022 testimony (Exhibit PG&E-4), PG&E initially proposed to underground approximately 3,300 miles from 2023 to 2026, at a forecast cost of approximately $9,980 million.[1501]

1498 Tr. Vol. 4, 508:1 to 509:1, Commissioner John Reynolds.

1499 PG&E-04, p. 4.3-29, lines 6-10.

1500 PG&E-17, lines 4.3-9, line 10 to p. 4.3-10, line 2.

1501 PG&E-04, p. 4.3-51, Table 4.3-11, sum of lines 4 and 7.

Intervenors have questioned several aspects of PG&E's undergrounding proposal, including the reasonableness of the proposed scope, pace, and costs. And, of course, various aspects of the proposal remain subject to change during extensive reviews in both the annual WMP process and the review process for PG&E's 10-year undergrounding plan under SB 884.

In response to this nascent regulatory environmenta and intervenors' concerns, PG&E is willing to reduce program costs and corresponding mileage targets, particularly in the outer years of the GRC period, and presents a reduced forecast as a reasonable outcome for this GRC, as shown in Tables 4-1 and 4-2 below:

TABLE 4-1:

SYSTEM HARDENING UNDERGROUND

PG&E'S ORIGINAL AND ADJUSTED CAPITAL FORECAST- MAT 08W AND 95F ($000s)

PG&E's Forecast	2021	2022	2023	2024	2025	2026	Total 2023-2026
Adjusted Forecast (08W)	$127,654	$491,625	$997,206	$1,288,141	$1,554,386	$2,085,850	$5,925,582
Rebuttal Forecast (08W)[(a)]	$127,654	$664,125	$1,246,650	$2,459,839	$2,934,731	$3,337,360	$9,978,580
Difference (08W)[(b)]	$0	$(172,500)	$(249,443)	$(1,171,698)	$(1,380,346)	$(1,251,510)	$(4,052,997)
Rebuttal Forecast (95F)[(c)]	$0	$85,875	$88,450	$71,511	$44,086	$0	$204,047
(a) PG&E-04, p. 4.3-51, Table 4.3-11, lines 4 and 7 (b) Differences due to rounding (c) PG&E-04, WP 23-13, line 8. PG&E's 95F forecast has not been adjusted.							

TABLE 4-2:
SYSTEM HARDENING UNDERGROUND
PG&E'S ADJUSTED UNDERGROUND MILES FORECAST – MAT 08W AND MAT 95F

PG&E's Forecast Miles	2021	2022	2023	2024	2025	2026	Total 2023-2026
Adjusted Underground Miles Proposal (MAT 08W)	30	139	308	415	527	750	2,000
Adjusted Underground Miles Proposal (MAT 95F)[(a)]	--	36	42	35	23	0	100
Adjusted Underground Miles - Total	30	175	350	450	550	750	2,100
(a) The number of underground miles tracked in MAT 95F has not been adjusted.							

This adjustment is consistent with PG&E's commitment to most effectively implement its undergrounding plan. The adjustment also is consistent with recommendations made by several intervenors for PG&E to reduce the pace and costs of the program during the 2023-2026 GRC period pending further regulatory review. The adjusted mileage targets balance a smaller work scope and lower costs with meaningful risk reduction, and will allow PG&E to target risk reduction in the highest wildfire risk areas to eliminate up to 20 percent of existing risk by year-end 2026. Among other benefits, the change in pace will reduce costs in the initial years of the program, therefore mitigating the bill impact on customers.

To be sure, there is vitally important wildfire risk-reduction work to be completed, and PG&E must begin implementing its undergrounding plans now. While PG&E begins its undergrounding work, PG&E will continue to rely on its PSPS, EPSS, and other programs to mitigate risks. But PSPS and EPSS negatively impact customers and cannot solely be relied upon as permanent solutions in lieu of undergrounding. As explained in PG&E's testimony, undergrounding will provide permanent risk reduction in the areas in which it is implemented, enhance reliability by reducing the need for PSPS and EPSS, enhance system resiliency, and provide other related benefits.

4.1.5 The Proposed Two-Way Wildfire Mitigation Balancing Account Provides Ratemaking Flexibility

While PG&E has adjusted its forecast miles to account for the considerations discussed above, it is important to recognize that PG&E's undergrounding plans are in their early stages, could continue to be impacted by factors outside of PG&E's direct control, and are subject to still further adjustments through the OEIS and Commission's regulatory review processes. The uncertainty in final project scope, timing, and costs further underscores the importance of the Commission's continued approval of the two-way Wildfire Mitigation Balancing Account (WMBA). As noted above, the ongoing review of PG&E's annual WMPs and 10-year undergrounding plan by the OEIS as well as the Commission's review of both forecast and recorded costs, will inform PG&E's decision-making and planning. Commissioner Reynolds' opening remarks further emphasized that ratemaking mechanisms should be flexible given these circumstances:

> As the WMP process continue to shape the evolution of utility wildfire risk management, our ratemaking process needs to be adaptable enough to adjust [for] the state's wildfire safety approach.[1502]

Consistent with these expectations, a two-way balancing account protects customers by requiring PG&E to refund any overcollections if recorded costs are less than forecasted, but allows PG&E to adjust its comprehensive wildfire mitigation strategy as needed as circumstance may change (or as directed by its regulators).

4.1.6 PG&E Remains Committed To Its Long-Term Plans To Underground 10,000 Miles As This Achieves The Greatest Overall Risk Reduction

Although PG&E plans to adjust the undergrounding mileage pace in the 2022-2026 period, PG&E remains fully committed to complete 10,000 miles of undergrounding to maximize wildfire risk reduction in the highest wildfire risk areas, in order to protect customers and communities from wildfire and other risks from electric distribution equipment and operations. PG&E will submit its 10-year undergrounding plan in 2023 in accordance with the

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1502 Tr. Vol. 4, 509:2-6, Commissioner John Reynolds.

schedule and guidelines that will be established by OEIS and the Commission in the coming months. The plan will provide details regarding PG&E's undergrounding proposal beyond the GRC period.

4.1.7 PG&E's Adjusted Overall Forecast For Electric Distribution Should Be Approved As It Reflects A Reasonable Outcome Of The Parties' Respective Positions In This Proceeding

As further detailed below, the adjustment will reduce PG&E's undergrounding and overall Electric Distribution (ED) forecast in this GRC, reflecting a reasonable outcome between PG&E's February 2022 request and intervenors' proposals to reduce the scope of PG&E's undergrounding proposal and other activities. The adjusted mileage target does not impact PG&E's TY 2023 expense forecast for ED, which as presented in the Joint Comparison Exhibit ("the JCE" or "PG&E-64") is $2,210[1503] million, of which $782 million, 35 percent, is uncontested.[1504] PG&E's expense forecast presented in the JCE including a change in escalation percentage (the September 22 updated escalation) is $2,597 million.[1505]

With the reduced undergrounding mileage targets for 2023-2026, PG&E's adjusted capital expenditures forecast for ED is $3,454 million in 2021, $3,859 million in 2022, $4,175 million in 2023, $4,514 million in 2024, $4,770 million in 2025, and $5,363 million in 2026. The difference between the capital forecast presented in the JCE and the adjusted capital expenditures forecast is $4,106 million (2023-2026) as shown in Table 4-3 below.

1503 PG&E-64, Column "PG&E (without Sept 6 Non-Labor Escalation Adjustment) includes all post-February 28, 2022 errata and concessions. *See* PG&E-64, p. 3-2, Table 3A-1 and all PG&E-04.

1504 *See* Appendix A, p. A-12, line 225. Calculated as: $782 million / $2,210 million = 35%.

1505 PG&E-64, p. 3-2, Table 3A-1, line "Total Exhibit (PG&E-04)," Column "PG&E (with Sept. 6 Non-Labor Escalation Adjustment)."

TABLE 4-3:
PG&E'S ELECTRIC DISTRIBUTION CAPITAL EXPENDITURES FORECAST
(MILLIONS OF DOLLARS)

PG&E's Forecast	2021	2022	2023	2024	2025	2026	Total (2023-2026) 2023-2026
Adjusted Forecast	$3,454	$3,859	$4,175	$4,514	$4,770	$5,363	$18,822
JCE Forecast[(a)]	$3,454	$4,031	$4,518	$5,645	$6,150	$6,615	$22,928
Difference	$0	$(173)	$(343)	$(1,131)	$(1,380)	$(1,252)	$(4,106)
(a) PG&E Opening Brief, p. 364.							

Approximately $628 million of PG&E's 2023 capital forecast, 14 percent, is uncontested.[1506]

PG&E's adjusted capital expenditures forecast including the September 2022 updated escalation is $3,571 million in 2021, $4,218 million in 2022, $4,730 million in 2023, $5,284 million in 2024, $5,594 million in 2025, and $6,151 million in 2026.[1507] The difference between PG&E's capital rebuttal forecast (including the September 2022 updated escalation) and PG&E's adjusted capital forecast (including the September 2022 updated escalation) is $4,761 million (2023-2026).[1508]

4.2 Electric Distribution Risk Management

In its Opening Brief, PG&E described how it uses risk-informed decision making to identify and implement the programs that target the key risk drivers of wildfire risk and other risks from electric distribution equipment and operations. PG&E also provided an overview of its wildfire risk modeling and addressed the effectiveness of its system hardening program to

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1506 *See* Appendix A, p. A-21, line 114. Calculated as: $628 million / $4,518 = 14%.

1507 PG&E-64, p. 3-15, Table 3B-3, line "Total Exhibit (PG&E-04)" (2021); p. 3-11, Table 3B-2, line "Total Exhibit (PG&E-04)" (2022); p. 3-7, Table 3B-1, line "Total Exhibit (PG&E-04)" (2023), Column "PG&E (with Sep 6 Capital Escalation Adjustment)." The forecasts for 2024-2026 are not included in the JCE but are provided here for reference.

1508 Calculated as: $26,519 million (PG&E Opening Brief, p. 364) - $21,758 million = $4,761 million (differences due to rounding).

mitigate wildfire risk.[1509] Most issues raised in parties' Opening Briefs are not new and have already been addressed by PG&E. Where parties raised new issues,[1510] PG&E addresses them in the following sections of this Reply Brief.

4.2.1 Summary Of Electric Distribution Risk Modeling Issues In PG&E's Opening And Reply Briefs

Table 4-4 below summarizes the issues raised by parties and where they are addressed in PG&E's Opening and Reply briefs. To align the issues between the Opening and Reply briefs, the table below describes the subject discussed in the briefs rather than providing the specific section header.

TABLE 4-4
ELECTRIC DISTRIBUTION RISK MANAGEMENT
SUMMARY OF ISSUES ADDRESSED IN OPENING AND REPLY BRIEFS

PG&E's Reply Brief		PG&E Opening Brief	
Section	**Subject**	**Section**	**Subject**
4.2.2	PG&E's adjusted undergrounding mileage proposal (2023-2026).	N/A	New issue – not addressed in Opening Brief
4.2.2.1	Comparing PG&E's adjusted undergrounding proposal to TURN's system hardening proposal.	4.2.2.2	Issues raised by TURN's regarding PG&E undergrounding program.
4.2.2.2	Cal Advocates' recommendations around prioritization and cost caps.	N/A	New issue – not addressed in Opening Brief
4.2.2.3	Parties' positions regarding the effectiveness of covered conductor.	4.2.2.3	The effectiveness of covered conductor at mitigating wildfire risk.
4.2.3	Operational failure/reliance on compliance programs and quality assurance/quality control to mitigate wildfire risk.	2.2.3	Replying to TURN's position on operational failure.
4.2.4	Using the WDRM to inform mitigation programs and prioritize highest wildfire risk miles.	4.2.1 and 4.2.5	PG&E's Wildfire Distribution Risk Model (WDRM) and Updates to the WDRM and how it impacted parties' risk analysis.
4.2.5	PG&E's inclusive definition of risk.	N/A	New issue– not addressed in Opening Brief
4.2.6	The role of RSE values in evaluating system hardening proposals.	4.2.3.3	The role of RSEs in values in selecting wildfire mitigations.
4.2.7	Correcting Cal Advocates' misconceptions about PG&E's risk modeling and risk mitigations,	N/A	New issue– not addressed in Opening Brief
N/A	No new issues to address	4.2.3.1	PSPS risk modeling.

1509 PG&E Opening Brief, pp. 365-378, Section 4.2.

1510 PG&E responds to issues raised by Cal Advocates, MGRA and TURN.

PG&E's Reply Brief		PG&E Opening Brief	
Section	**Subject**	**Section**	**Subject**
N/A	No new issues to address	4.2.3.2	Use of PSPS and EPSS to mitigate wildfire risk.
N/A	No new issues to address	4.2.3.4	Cal Advocates proposed capital reductions for emergency work.

4.2.2 PG&E's Adjusted Proposal For Undergrounding Miles In The 2023 GRC Period

As discussed above, PG&E has continued to evaluate it undergrounding plans and is adjusting the mileage pace in 2022-2026. PG&E's original proposal and adjusted proposal for undergrounding miles (not including underground miles related to its Community Rebuild program)[1511] are shown in Table 4-5 below.

TABLE 4-5:
SYSTEM HARDENING UNDERGROUND
PG&E'S ORIGINAL AND ADJUSTED UNDERGROUND MILES FORECAST – MAT 08W(a)

PG&E's Forecast Underground Miles	2021	2022	2023	2024	2025	2026	Total 2023-2026
Adjusted MAT 08W Underground Miles	30	139	308	415	527	750	2,000
Original MAT 08W Underground Miles Forecast(b)	30	185	382	786	990	1,200	3,358
Difference(c)	0	(46)	(75)	(370)	(463)	(450)	(1,358)
(a) PG&E also adjusted its forecast number of underground miles tracked in MAT 95F. See Table 4-2 above. (b) PG&E-04, p. 4.3-51, Table 4.3-11, lines 5 and 8. (c) Differences due to rounding.							

The primary objective of the program is to target undergrounding in the areas where the wildfire threat and disruptions to customers and communities from PSPS and EPSS are the highest.[1512] PG&E's undergrounding program will effectively reduce the ignition risk to zero for lines that have been converted from overhead to underground. Even though PG&E is reducing the number of underground miles forecast in this GRC period, PG&E remains fully

1511 The Community Rebuild undergrounding program, tracked in MAT 95F, is discussed in Section 4.23 of this Reply Brief.

1512 PG&E-04, p. 3-2, lines 17-23.

committed to its long-term 10,000-mile undergrounding program and to its comprehensive wildfire mitigation strategy that relies on undergrounding, overhead system hardening, EPSS, PSPS, situational awareness, and other mitigations to provide comprehensive risk reduction across the HFTD.[1513]

PG&E estimated that its original undergrounding proposal would reduce wildfire risk in the HFTD by approximately 33 percent between 2024 and 2026.[1514] PG&E now estimates that its adjusted proposal will reduce wildfire risk through undergrounding in the HFTD by up to 20 percent between 2024 and 2026.[1515] As with its original proposal, PG&E's adjusted proposal includes reliance on EPSS, PSPS and other mitigations to reduce risk while undergrounding occurs.

4.2.2.1 Comparing PG&E's Adjusted Undergrounding Proposal To TURN's System Hardening Proposal

TURN agrees with PG&E that undergrounding provides the highest absolute risk reduction value of any mitigation measure[1516] and that undergrounding is the appropriate choice for mitigating the highest risk circuits in the HFTD.[1517] Where TURN and PG&E differ is in the mix of underground and overhead system hardening miles proposed for this rate case period. PG&E proposes to underground approximately 2,000 high risk circuit miles in the HFTD during the GRC period – thereby eliminating almost all the ignition risk on those circuits. PG&E estimates that undergrounding is approximately 99 percent effective at reducing wildfire risk.[1518] TURN, by comparison, recommends undergrounding only 200 circuit miles –

1513 PG&E-04, p. 3-2, lines 14-19.

1514 Tr. Vol. 9, 1676:6-16, PG&E/McGregor.

1515 The 20 percent risk reduction calculated by PG&E is based on PG&E's analysis of its adjusted undergrounding miles.

1516 TURN-11, p. 39, lines 23-24.

1517 TURN Amended Opening Brief, p. 385.

1518 PG&E-04, p. 3-6, line 15.

approximately one-tenth as many miles as PG&E's proposal – and installing overhead covered conductor, a mitigation that is only 62 percent effective[1519] at reducing wildfire risk, on another 1,800 circuit miles in the HFTD.[1520] PG&E estimates that TURN's proposal will remove approximately 4 percent of the risk through undergrounding, much less than what PG&E is proposing, while mitigating the other high risk miles using a less effective measure. It is imperative that PG&E deploy the most effective mitigation measure available to protect those areas of its service area at the highest risk of catastrophic wildfire.

4.2.2.2 Cal Advocates' And TURN's Recommendations Regarding Prioritization Are Unnecessary And Should Not Be Approved

Cal Advocates' makes two recommendations related to PG&E's undergrounding work execution proposal: (1) the Commission should require that 80 percent of PG&E's annual underground mileage be in the top 10 percent of risk-ranked circuit segments—ranked by the per-mile risk in HFTDs;[1521] and (2) PG&E should be required to include a cost benefit analysis that considers alternatives to undergrounding or some combination of undergrounding and such alternatives.[1522] TURN also recommends that the Commission require PG&E to conduct at least 90 percent of system hardening on circuits containing the top 50 percent of wildfire risk.[1523] PG&E addresses these recommendation below.

Cal Advocates' and TURN's recommendations regarding prioritization targets are duplicative and unnecessary. PG&E already provides detailed information about how it will prioritize its undergrounding miles in its WMP filings. In the 2022 WMP that was approved by OEIS on November 10, 2022, PG&E stated that it will address the top 20 percent riskiest areas of the HFTD based on risk model output. This includes more than 90 percent of undergrounding

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1519 TURN Amended Opening Brief, p. 387.

1520 TURN Amended Opening Brief, p. 378.

1521 Cal Advocates Opening Brief, p. 140.

1522 Cal Advocates Opening Brief, p. 137.

1523 TURN Amended Opening Brief, Summary of Recommendations, p. xx.

work being completed in the top-risk areas from 2024 to 2026, prior to adding PSPS, Public Safety Specialist-identified, and fire rebuild projects. In total, PG&E estimated 88 percent of its undergrounding projects to be within the top 20 percent of risk-ranked circuit segments from 2022 to 2026.[1524] PG&E will submit its 2023-2025 WMP in February 2023. This WMP will include PG&E's underground prioritization plans for the years 2023-2025 pending OEIS's evaluation and approval. PG&E should not be held to different commitments in multiple regulatory proceedings and believes that adhering to the commitments made in the WMP and approved by OEIS is a reasonable approach.

Cal Advocates' recommendation to require PG&E to include a cost-benefit analysis that considers alternatives to undergrounding is premature. In this GRC, PG&E is proposing a suite of wildfire mitigations. In some cases, undergrounding may not be the right solution (i.e., undergrounding may not be feasible), but it is the right solution for most of the highest risk areas in the HFTD. The Commission has been considering the use of cost-benefit analyses, and what form that analysis would take, in the Risk-Based Decision-Making OIR.[1525] On November 3, 2022 the Commission issued a proposed decision[1526] that directs the IOUs to implement a newly described Cost-Benefit Approach in their next respective GRC cycles, beginning with PG&E's 2024 RAMP filing.[1527] PG&E will comply with the Commission decision regarding cost-benefit analyses. Requiring another or different cost-benefit analysis prior to PG&E's 2024 RAMP as Cal Advocates appears to recommend is unnecessary.

1524 2022 Wildfire Mitigation Plan, OEIS Docket #2022-WMP, Final Decision on PG&E's 2022 Wildfire Mitigation Plan Update (Nov. 10, 2022), p. 77.

1525 R.20-07-013, *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning* (Jan. 27, 2020) (RDF OIR).

1526 R.20-07-013, *Ph. II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in D.18-12-014 and Directing Environmental and Social Justice Pilots* (Nov. 3, 2022) ("Proposed Decision re RDF Modifications" or "Proposed Decision").

1527 Proposed Decision re RDF Modifications, p. 22. *See also id*., pp. 56-57, OP 2.

4.2.2.3 Parties' Claims About The Mitigation Effectiveness Of Covered Conductor Should Not Be Relied On

PG&E estimates that undergrounding distribution lines is approximately 99 percent effective at mitigating ignition risk on those lines whereas overhead system hardening is only 62 percent effective.[1528] Parties do not dispute that undergrounding is the most effective risk mitigation solution available to PG&E and that it should be deployed in the highest risk parts of the HFTD.[1529] However, some parties propose alternate mitigations based primarily on overhead covered conductor and claim that overhead conductor is more effective at mitigating wildfire risk than PG&E's experience and analysis indicate.

MGRA argues that covered conductor may be as much as 78.8 percent effective with a 95 percent confidence level at mitigating ignition risk. TURN states that covered conductor may be as much as 90 percent effective in reducing ignitions from vegetation contact and equipment failure. The effectiveness percentage MGRA cites is based on Southern California Edison Company's (SCE) experience while the effectiveness percentage TURN cites to refers to PacifiCorp's experience.[1530] Although PG&E has not independently analyzed SCE's or PacifiCorp's calculations, mitigation effectiveness depends on various factors including the location of the system hardening projects, environmental and weather conditions, etc. PG&E's service area is significantly different than SCE's and PacifiCorp's service area in ways that could explain a difference in mitigation effectiveness. PG&E's service area, for example, includes a diverse mixture of forest systems and transition systems containing unique vegetative pressures, stands of dense forest and extremely large trees. It includes coastal forest, plains, woodland areas, mixed conifer forest, and alpine forest. SCE's service area contains only limited forested areas along with dense infrastructure, fewer stands of dense trees, and large arid

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1528 PG&E-04, p. 3-6, lines 13-15.

1529 *See* CUE Opening Brief, pp. 14 and 16; MGRA Opening Brief, pp. 10 and 46; and TURN-11, p. 39, lines 23-24.

1530 MGRA Opening Brief, p. 55; TURN Amended Opening Brief, p. 393.

desert regions. PacifiCorp's territory is made up of a more homogeneous forest and, because it is farther north, receives better moisture than PG&E's service area does. The effectiveness percentage that PG&E calculated for covered conductor in its own territory and based on its own data is the only effectiveness measure that can be relied upon when comparing PG&E's system hardening proposal against other proposals. Parties' claims that covered conductor may be anything more than 62 percent effective at mitigating ignition risk in PG&E's service area are unsupported and should not be considered when evaluating the effectiveness of PG&E's proposed mitigation programs.

4.2.3 Relying On Compliance Programs Alone Is Not Enough To Reduce Wildfire Risk

TURN claims that, "ensuring compliance programs are implemented well through an Enhanced Quality Assurance and Quality Control (QA/QC) strategy would significantly reduce the frequency of wildfires and therefore significantly reduce the Wildfire risk."[1531]

PG&E agrees with TURN that ensuring compliance programs – also referred to as risk control programs – are properly implemented through enhanced quality assurance and quality controls programs will help reduce the frequency of wildfires. As such, quality assurance and quality control programs are critical components of PG&E's risk mitigation strategy.[1532] PG&E is working to improve certain of its control programs and quality assurance and quality control efforts in order to continue managing wildfire risk. In PG&E's 2022 WMP Update, OEIS found that PG&E has high find and failure rates in its quality assurance and quality control of asset inspections.[1533] In response to this finding, PG&E submitted to OEIS detailed plans for improving quality assurance and quality control of asset inspections. For example, PG&E committed to improve training programs focused on ignition risk, performing real-time

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1531 TURN Amended Opening Brief, pp. 363-364.

1532 PG&E-17, p. 3-12, lines 4-27.

1533 PG&E's 2022 WMP, OEIS Docket #2022-WMP, Final Revision Notice Responses, Critical Issue RN-PG&E-22-08 (June 27, 2022), p. 32.

validation and correction of failed or non-conformance issues in systems inspections, and increasing the pace of feedback to clearly communicate expectations back to PG&E and contractor inspectors and leadership teams.[1534]

However, improving control programs alone is not enough to reduce wildfire risk. By definition, control or compliance programs allow PG&E to maintain the baseline amount of risk on the system. It is only through mitigation programs that PG&E can reduce the risk profile.[1535] As PG&E's risk management witness Mr. Andy Abranches explained during evidentiary hearings when asked if PG&E would agree that the focus of PG&E's wildfire risk reduction efforts should be to prevent failures to comply with regulatory requirements,[1536]

> We had to go well above the compliance requirement because of the change in circumstances. And we have continued to do that because those controls that are engendered by those programs only allow us to keep the risk – only allow us to keep the current risk within check without changing the profile of the risk. And it is our objective in this GRC and in our wildfire mitigation plans to change that trajectory. Hence, the request for the undergrounding program which changes how the grid is constructed.[1537]

PG&E is not the only Investor Owner Utility (IOU) who recognizes that given climate change and increasingly hotter and drier conditions nearly year-round, utilities must implement mitigation programs to reduce wildfire risk, rather than relying just on compliance work alone. In their Opening Brief, SCE, San Diego Gas & Electric Company and Southern California Gas Company (Joint IOUs) note that TURN's argument conflicts with Senate Bill 901, which mandates that IOUs ". . . construct, maintain, and operate [their] electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfires posed by those electrical lines and equipment" and that "[t]o achieve this risk-minimization, a utility's Wildfire Mitigation Plan

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1534 PG&E's 2022 WMP, OEIS Docket #2022-WMP, Final Revision Notice Responses, Critical Issue RN-PG&E-22-08 (June 27, 2022), pp. 32-41.

1535 PG&E-17, p. 3-11, lines 21-24.

1536 Tr. Vol. 9, 1652:17-24, TURN/Long.

1537 Tr. Vol. 9, 1653:22 to 1654:6, PG&E/Abranches.

(WMP) must be designed "to ensure its system will achieve the highest level of safety, reliability, and resiliency … ."[1538] The Joint IOUs also cite Assembly Bill 1054, which mandates that the electrical corporations lessen the risk of catastrophic wildfires by engaging in additional system hardening.[1539]

Contrary to TURN's claim that compliance programs alone are enough to reduce wildfire risk, they are not. PG&E must continue to aggressively pursue mitigation programs to change the system risk profile and meaningfully reduce wildfire risk.

4.2.4 The Risk Modeling And Analysis In PG&E's Rebuttal Testimony Provides Sufficient Information For Parties To Evaluate PG&E's Undergrounding Proposal

PG&E updated its wildfire risk model between the time it submitted its Amended Application in March 2022 and its rebuttal testimony in July 2022. TURN contends that these changes "make it impossible to meaningfully evaluate the risk reduction and cost effectiveness of PG&E's program, as modified in its rebuttal testimony."[1540]

PG&E used its 2021 Wildfire Distribution Risk Model (referred to as WDRM version 2) to inform its March 2022 Amended Application. PG&E explained that the WDRM is a planning model that calculates wildfire risk probabilities of ignition and consequence scores for the overhead distribution system in the HFTD at the circuit segment level and that it informs the development of mitigation programs and helps to prioritize the highest wildfire risk miles on PG&E's distribution system in the HFTD.[1541] In rebuttal testimony, PG&E explained that the next version of the WDRM (referred to as WDRM version 3) had been approved for use in April 2022 and that PG&E had used WDRM version 3 to inform the targeting and mileage

1538 Joint IOUs Opening Brief, p. 8.

1539 Joint IOUs Opening Brief, p. 8.

1540 TURN Amended Opening Brief, p. 399.

1541 PG&E-04, p. 3-17, Table 3-3, line 4.

tranches for its undergrounding program forecast.[1542] The WDRM version 2 and WDRM version 3 are evolutions of the same risk model – with the WDRM version 3 incorporating a number of improvements.[1543] Both WDRM version 2 and version 3 estimate wildfire risk values for circuit segments of the overhead distribution system in PG&E's HFTD and provide insights into the locations with high wildfire risk by driver to inform the development of mitigation programs. The WDRM version 3 improves upon the WDRM version 2 with more sophisticated risk analyses such as improved ground fuels data and richer ignitions, outages, and damages driver data, but in no way invalidates the risk modeling conducted using the WDRM version 2.

In rebuttal testimony, PG&E also introduced the Simplified Wildfire Risk Spend Efficiency (RSE) – also referred to as the Wildfire Feasibility Efficiency (WFE) factor. The Simplified Wildfire RSE considers three factors – mitigation risk reduction benefits, mitigation cost estimate, and the feasibility of underground construction – mainly to inform work prioritization.[1544]

PG&E's risk management witness Mr. Paul McGregor explained how PG&E used wildfire distribution risk models and the WFE to develop and then refine its planned undergrounding portfolio of work.

> The WFE is based on the wildfire distribution risk model, version 3, and that was used to prioritize the 2024 to 2026 work, work that was originally prioritized under our 2021 version 2 risk model. It was already work that was in progress from a scoping perspective so that you would see that in your 2023 project list.[1545]

1542 PG&E-17, p. 3-3, lines 22-27.

1543 PG&E-17, p. 3-4, lines 1-3.

1544 PG&E-17, p. 3-6, lines 12-14.

1545 Tr. Vol. 9, 1667:8-15, PG&E/McGregor.

> The WFE tool then used the output from the version 3 risk model and applied the feasibility component to that calculation for further prioritization and bundling.[1546]

> [W]e used our wildfire distribution risk model to prioritize all of the circuit segments in the high fire-threat district and the high fire-risk area. From there, we applied the feasibility adjustments, and that allowed us to bundle the CPZs into an order where we could prioritize them and execute that based on feasibility to achieve the most risk reduction in the tranches that we developed so that first tranche was 3,300 miles of circuit segments.[1547]

TURN's claim that PG&E's introduction of an updated risk model in rebuttal testimony made it impossible to meaningfully evaluate the risk reduction and cost effectiveness of PG&E's programs is unreasonable.[1548] PG&E built upon and improved its risk models but did not fundamentally change the methodology. PG&E's undergrounding forecast has always been based on completing the highest risk work possible during the GRC period and was never about completing a specific list of projects. This has not changed:

> The exact scope of PG&E's System Hardening Program will continue to evolve as PG&E enhances its Wildfire Risk Model as well as performs more detailed scoping and inspections, estimating, and engineering review. Because PG&E's System Hardening Program is a first of its kind program, some level of uncertainty as to the exact number of miles of undergrounding versus overhead system hardening is to be expected.[1549]

TURN further claims that "[t]he net result of all these changes is that the analyses and numbers presented by intervenors in their testimonies in June of 2022, especially concerning the risk reduction benefits of system hardening measures, are no longer comparable to the numbers presented by PG&E in its rebuttal testimony."[1550] For example, TURN claims that its undergrounding witness Mr. Eric Borden "found that the top 20% of ignition risk was contained

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1546 Tr. Vol. 9, 1668:1-4, PG&E/McGregor.

1547 Tr. Vol. 9, 1668:11-22, PG&E/McGregor.

1548 After PG&E filed its rebuttal testimony parties had the opportunity to ask PG&E questions through discovery. TURN asked PG&E several questions about information included in its rebuttal testimony. (See for example, TURN-203, PG&E Responses to Data Requests TURN_220–Questions 03, 07, 10, 11, 12 and 15.)

1549 PG&E-04, p. 4.3-27, lines 10-16.

1550 TURN Amended Opening Brief, p. 399 (fn. omitted).

on 480 circuit miles. Now PG&E claims that the top 20% of risk is contained in a much larger 1,300 miles."[1551] TURN's claim here is without merit. PG&E's rebuttal testimony shows that the top 20 percent of cumulative risk is contained in the range of 1,300 miles.[1552] Mr. Borden's conclusion that the top 20 percent of risk was contained on 480 circuit miles appears to be based on an error. TURN determined that the top 20 percent of risk was contained on 480 circuit miles by summing the average of the risk scores for each circuit protection zone as opposed to summing the total risk scores for each circuit protection zone.[1553] Summing the average risk scores artificially reduces the gradient of the risk curve.

PG&E will continue to refine its work plans as new and better risk information becomes available or if factors outside of PG&E's control impede work in certain areas. The WDRM version 3 and Simplified Wildfire RSE simply provide the Commission and parties with supplemental information about the work PG&E is proposing as that information becomes available. It is unreasonable to think PG&E would stop working to improve its risk models based on the schedule in a regulatory proceeding. The risk modeling and analysis that PG&E presented in its rebuttal testimony is sufficient to evaluate PG&E's undergrounding proposal.

4.2.5 PG&E's Inclusive Definition Of Risk Is Reasonable Because It Incorporates Items That Impact Underground Prioritization

TURN argues that "[t]he Commission must hold PG&E accountable for targeting undergrounding only to the riskiest circuits as identified by the WDRM, without including the other meaningless risk factors used by PG&E to define its subjective 'fulsome risk.'"[1554]

PG&E's risk management witness Mr. Abranches described the other risk factors that TURN is referring to during evidentiary hearings,

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1551 TURN Amended Opening Brief, p. 399.

1552 PG&E-17, p. 3-10, Figure 3-2 shows that the cumulative risk addressed by undergrounding miles in the HFTD. The top 20% of risk addressed is between 799 and 1,770 (799 + 971) miles.

1553 TURN Amended Opening Brief, p. 399; TURN-11, p. 28, Figure 10.

1554 TURN Amended Opening Brief, p. 408.

> . . . there are risks identified by a risk model that we shared very openly, the risks identified by public safety specialists – this is ex-firefighters that identify by walking the local conditions· to identify locations that may be a risk model does not catch in its full scope. ·And there are risks from public safety power shutoff events that happen on extremely windy days, driving and changing the risk profile for a very short period of· time. So those are additional miles there. And, lastly, . . . fires are occurring in California effectively every season. And when a fire occurs in California, it is nature indicating to us where risk has materialized independent of any mathematical models. So we take all four of those considerations in when we define risk.[1555]

The additional risk factors such as locations often impacted by high wind events, areas where wildfires occurred in the past, or challenging terrain not identified by the risk models, that PG&E builds into its underground project planning are far from meaningless. They are important considerations for keeping PG&E's customers and communities safe and for providing more reliable service.

No risk model is perfect. PG&E needs the flexibility to build upon the outputs from the risk models and consider other factors when addressing system risk. TURN, for example, agrees that certain deviations from the risk models are reasonable, stating that it is, ". . . open to a limited exception, perhaps of 10% of the work, to allow circuits that may not be identified as risky by the model, but may warrant undergrounding based on other considerations, such potential difficulties in executing effective vegetation management."[1556] Some deviation from the risk model – and a broader definition of risk – is reasonable whether it is due to vegetation management difficulties, construction feasibility, risks identified by public safety specialists, or for other reasons. This broader definition of risk factors does not nullify the usefulness of the risk models, rather it addresses real world items that impact the undergrounding program and should not be ignored. PG&E's plans in this GRC period will focus on undergrounding high risk circuit segments in the HFTD and removing as much risk as possible from the system.

1555 Tr. Vol. 8, 1390:7-26, PG&E/Abranches.

1556 TURN Amended Opening Brief, p. 408.

4.2.6 The Role Of RSEs In Evaluating Underground And Overhead System Hardening

Parties question PG&E's decision to focus primarily on undergrounding to mitigate ignition risk given that undergrounding has a lower RSE than overhead system hardening.[1557] TURN also calculates a lower unit cost for "covered conductor" (also referred to as overhead system hardening) than PG&E and notes that when this unit cost is used the difference between the RSEs for undergrounding and covered conductor was even larger.[1558] TURN concludes its analysis by asking, "[g]iven these data, the obvious question is how can PG&E justify spending huge amounts of money on the less cost-effective underground options?"[1559]

RSEs are not a significant driver of the choice between overhead and undergrounding because the two mitigations have similar RSEs. Table 4-6 below shows that while overhead hardening has a higher RSE in the test year, by the end of the GRC period undergrounding has the higher RSE.[1560]

TABLE 4-6:
RSE VALUES FOR UNDERGROUDING AND OVERHEAD HARDENING[1561]

Mitigation	2023	2024	2025	2026
Undergrounding[(a)]	4.8	5.0	5.4	5.9
Overhead Hardening[(b)]	6.1	5.9	5.8	5.6
(a) RSEs based on PG&E's original underground proposal.				
(b) PG&E-04, p. 3-6, Table 3-1.				

1557 MGRA Opening Brief, p. 44; TURN Amended Opening Brief, pp. 385-388.

1558 TURN Amended Opening Brief, p. 386.

1559 TURN Amended Opening Brief, p. 387.

1560 TURN notes in its Amended Opening Brief that PG&E recalculated the RSEs and found that covered conductor has an RSE of 7.55 while undergrounding has an RSE of 4.40. (TURN Amended Opening Brief, p. 386, fn. 1135.) PG&E performed this calculation as part of its 2022 WMP; the recalculated RSEs apply only to work planned for 2022 and do not impact PG&E's mitigation strategy for the GRC period. (PG&E's 2022 WMP, OEIS Docket #2022-WMP, PG&E Response to Revision Notice RN-PG&E-22-13 (June 27, 2022), 2022-06-27_PGE_22-13_RNR_R1_Atch01, Table 12, row 38, cells N38, P38, Q38, R38 and X38).

1561 PG&E recalculated the RSEs for undergrounding based on its adjusted undergrounding forecast and confirmed that the RSEs have not changed from the RSEs based on PG&E's February 25, 2022 forecast.

Moreover, as discussed in PG&E Opening Brief and rebuttal testimony, RSEs still have significant uncertainty due to the nature of the inputs and models used, and are therefore only rough measures for making risk-based decisions.[1562] For this reason, small differences between RSEs for overhead system hardening and undergrounding should not be construed as dispositive of the choice that should be made. The S-MAP Settlement Agreement and existing Commission precedent make clear that RSEs are not supposed to be the sole determinant of funding decisions or mitigation prioritization.[1563] PG&E also discusses these issues in Section 2.3, above.

Here, undergrounding is a more appropriate mitigation for the riskiest circuit miles in the HFTD than overhead system hardening, notwithstanding the minor difference in RSEs, because undergrounding provides near total elimination of ignition risk. Underground lines are not vulnerable to tree strikes caused by high-winds and are better protected from wildlife, objects, and environmental conditions that cause degradation and failure. Undergrounding is the best way for PG&E to keep its customers and communities in the areas of greatest wildfire risk safe.[1564] Undergrounding also improves grid reliability and customers will experience fewer power shutoffs as the underground program progresses.[1565] In comparison, overhead system hardening only eliminates an estimated 62% of ignition risk so any circuit mitigated through overhead hardening will still carry a significant amount of residual risk and will require additional mitigations such as PSPS and EPSS in perpetuity.

Finally, TURN's contention that the difference between the RSEs for overhead hardening and undergrounding is even greater if TURN's proposed unit costs for covered conductor are used in place of PG&E's forecast amounts for overhead system hardening should be disregarded. PG&E explained in Section 4.3.2.2.1 of its Opening Brief that TURN's unit cost assumptions,

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1562 PG&E Opening Brief, pp. 37-38; PG&E-15-E, p. 1-36, line 3 to p. 1-39, line 22.

1563 PG&E Opening Brief, pp. 38-39.

1564 PG&E-04, p. 4.3-10, lines 12-15.

1565 PG&E-04, p. 4.3-10 lines 19-27.

based on its belief that it is unnecessary to replace certain assets that do not pose a significant ignition risk as part of the installation of covered conductor,[1566] are wrong. As PG&E explained, 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.[1567] Installing different components at different times would require PG&E to mobilize multiple crews to the same site, which would increase costs.[1568] Also, to the extent there is non-exempt equipment currently in place, it would violate PG&E's standards to re-install non-exempt equipment.[1569] PG&E's approach reflects sound utility practice, as the replacement of all components at the same time better ensures overall reliability and system performance.

4.2.7 Correcting Cal Advocates' Misconceptions About PG&E's Risk Modeling And Risk Mitigations

Cal Advocates makes several claims in its Opening Brief related to PG&E's risk modeling and risk mitigations that are incorrect. PG&E corrects those misstatements below.

First, Cal Advocates claims that "PG&E admits that EPSS and enhanced vegetation management (EVM), are only secondary to undergrounding and are essentially stop-gap mitigation measures to support the undergrounding program."[1570] This is incorrect. The EPSS and vegetation management programs, along with undergrounding, are key elements of PG&E's integrated wildfire mitigation portfolio and will be implemented throughout the HFTD, not just in areas that will subsequently be undergrounded. The PG&E testimony that Cal Advocates cites in its Opening Brief clearly explains, "PG&E envisions EPSS as part of an integrated wildfire

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1566 TURN-11, p. 24, lines 11-13.

1567 PG&E-17, p. 4.3-37, lines 17-20.

1568 PG&E-17, p. 4.3-37, lines 20-22.

1569 PG&E-17, p. 4.3-37, lines 22-24.

1570 Cal Advocates Opening Brief, p. 130.

risk mitigation solution that will protect against vegetation and other ignition causes while undergrounding work progresses and as the scope of EVM is reduced."[1571]

Second, Cal Advocates claims that "PG&E now claims that undergrounding is significantly more effective at reducing wildfire and can be achieved at a low unit cost without providing the data that supports both contentions on the record of this proceeding."[1572] This is incorrect. In its March 2022 Amended Application, PG&E explained that undergrounding distribution assets is 99 percent effective at reducing wildfire risk.[1573] Regarding PG&E's forecast unit costs for undergrounding work, PG&E provided information about the unit costs and underlying assumptions in opening testimony[1574] and rebuttal testimony.[1575] Cal Advocates also had ample opportunity to ask PG&E for additional information during discovery. At evidentiary hearings, PG&E's undergrounding and risk witnesses were available for cross-examination for two days. During those two days Cal Advocates' attorney asked only one question about undergrounding costs (related to the cost implications of scaling from 100 miles to 1,200 miles per year) and did not ask any questions at all about the effectiveness percentages of different mitigations.

Third, Cal Advocates argues that PG&E did not submit its current undergrounding proposal in the RAMP proceeding and that the current proposal received lower risk scores. Cal Advocates concludes with, "[f]ailing to submit a proposal in the RAMP and then modeling it after the conclusion of RAMP defeats the purpose of the proceeding [and] undermines the development of risk-informed decision-making processes for California electric utilities."[1576]

1571 PG&E-04, p. 3-7, lines 5-8.

1572 Cal Advocates Opening Brief, p. 132.

1573 PG&E-04, p. 3-6, lines 13-15.

1574 PG&E-04, p. 4.3-29, line 12 to p. 4.3-32, line 5.

1575 PG&E-17, p. 4.3-16, line 22 to p. 4.3-18, line 20; p. 4.3-29, line 15 to p. 4.3-34, line 21.

1576 Cal Advocates Opening Brief, p. 132.

This is incorrect. PG&E modeled its wildfire risk in the RAMP proceeding and again in the GRC using the tools required by the S-MAP Settlement Agreement. The wildfire risk received similar test-year baseline risk scores in both models – 25,127 in RAMP and 23,220 in the GRC.[1577] The S-MAP Settlement Agreement does not prohibit utilities from identifying new mitigations, rather, the settlement requires utilities to explain their rationale for selecting mitigations.[1578] PG&E has provided ample support on the record about why it selected its proposed wildfire mitigations. PG&E has not undermined the development of risk-informed decision making, rather, PG&E has been open and transparent about its use of advanced risk modeling tools to develop its proposed mitigation portfolio.

4.3 Wildfire System Hardening

PG&E's System Hardening Program focuses on mitigating the wildfire risk posed by distribution overhead assets in and near HFTDs in PG&E's service area. This program targets the highest wildfire risk miles and applies various mitigation activities to eliminate or reduce those risks, including: (1) undergrounding, (2) overhead system hardening, (3) line removal, (4) remote grid alternatives, and (5) relocation of overhead facilities. Distribution overhead assets represent a high ignition risk due to a combination of high exposure and proximity to risk factors such as vegetation. The scope, location, and timing of PG&E's system hardening activities will evolve as PG&E continues to enhance its wildfire risk modeling; perform more detailed scoping and inspections, estimating, and engineering reviews; and engage with regulators, stakeholders, and customers.

4.3.1 Undergrounding

In its Opening Brief, PG&E described the scope, timing, and benefits of PG&E's undergrounding proposal. Most issues raised in intervenors' Opening Briefs are not new and

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1577 PG&E-04, p. 3-23, lines 1-7.

1578 D.18-12-014, Attachment A, Appendix A, p. A-14, Row 26 ("Mitigation Strategy Presentation in the RAMP and GRC").

have been addressed by PG&E in its rebuttal testimony and Opening Brief. Where intervenors raised new issues,[1579] PG&E addresses them in the following sections of this Reply Brief.

Table 4-7 below summarizes the issues raised by parties and addressed in PG&E's Opening and Reply Briefs.

TABLE 4-7:
ELECTRIC DISTRIBUTION - UNDERGROUNDING
SUMMARY OF ISSUES ADDRESSED IN OPENING AND REPLY BRIEFS

PG&E's Reply Brief		PG&E Opening Brief	
Section	**Subject**	**Section**	**Subject**
4.3.1.1	PG&E's adjusted forecast for undergrounding	N/A	New concession – not addressed in Opening Brief
4.3.1.2	Undergrounding scope	4.3.1.1	The pace of work and scope of PG&E's undergrounding program
4.3.1.3	Work execution	4.3.1.3	PG&E's ability to effectively address undergrounding implementation challenges
4.3.1.4	Undergrounding program costs	4.3.1.2 and 4.3.1.4	The cost effectiveness of PG&E undergrounding program. Unit cost targets
4.3.1.5	Issues raised by telecommunications providers	4.3.1.5	Issues raised by telecommunications providers
4.3.1.6	Non-forecast recommendations	4.3.1.7	Other issues
N/A	No new issues.	4.3.1.5	Updating communities and stakeholders about undergrounding activities

4.3.1.1 PG&E's Forecast For Wildfire System Hardening And Summary Of Intervenors' Positions

PG&E is focused on aggressively mitigating the highest wildfire risk areas in its service area. Undergrounding overhead distribution lines provides near total elimination of wildfire risk, reduces customer impacts due to Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS) programs, and improves system reliability and resiliency.[1580] PG&E is committed to undergrounding 10,000 miles in and near the HFTD in order to remove approximately 70 to 80 percent of the wildfire risk and reduce reliance on the PSPS and EPSS programs.

1579 PG&E responds to issues raised by Cal Advocates, AARP, AT&T, CFBF, Comcast, MGRA, TURN and Wild Tree.

1580 PG&E-04, p. 3-2, lines 14-26.

As noted in Section 4.1, PG&E's specific plans for the 10,000 mile undergrounding program will necessarily continue to be dynamic and evolve, reflecting among other things, the ongoing work and learnings of PG&E's project team and input from external stakeholders, including regulatory agencies reviewing and approving PG&E's plans. Further, several intervenors have requested reduction in the cost, scope and pace of the program. In response, PG&E is willing to adjust its undergrounding program forecast in this GRC period. This adjustment reduces the associated cost forecast by more than $4 billion and the number of miles forecast in this GRC period by approximately 40 percent.[1581] The corresponding forecast reduction provides a reasonable outcome between PG&E's February 2022 request and intervenors' proposals to reduce the scope of PG&E's undergrounding proposal and other activities. Table 4-8 provides a comparison between PG&E's adjusted forecast and rebuttal forecast for MAT 08W (which does not include the Community Rebuild costs discussed in Exhibit PG&E-04, Chapter 23).

TABLE 4-8:
SYSTEM HARDENING UNDERGROUND
PG&E'S ORIGINAL AND ADJUSTED CAPITAL FORECAST- MAT 08W($000s)

PG&E's Forecast	2021	2022	2023	2024	2025	2026	Total 2023-2026
Adjusted Forecast	$127,654	$491,625	$997,206	$1,288,141	$1,554,386	$2,085,850	$5,925,582
Rebuttal Forecast[a]	$127,654	$664,125	$1,246,650	$2,459,839	$2,934,731	$3,337,360	$9,978,580
Difference[b]	$0	$(172,500)	$(249,443)	$(1,171,698)	$(1,380,346)	$(1,251,510)	$(4,052,997)

(a) PG&E-04, p. 4.3-51, Table 4.3-11, lines 4 and 7.
(b) Differences due to rounding

As shown in Table 4-9, for MAT 08W, PG&E plans to complete 2,000 underground miles between 2023 and 2026,[1582] compared to PG&E's original forecast of 3,358 miles, a reduction of 1,358 miles in this GRC forecast.

1581 *See* Table 4-8.

1582 PG&E plans to complete additional underground miles that are tracked in MAT 95F shown in Table 4-2 above in Section 4.1.

TABLE 4-9:
SYSTEM HARDENING UNDERGROUND
PG&E'S ORIGINAL AND ADJUSTED UNDERGROUND MILES FORECAST – MAT 08W(a)
(MILES)

PG&E's Forecast Miles	2021	2022	2023	2024	2025	2026	Total 2023-2026
Adjusted Underground Miles	30	139	308	415	527	750	2,000
Original Underground Miles Forecast[(b)]	30	185	382	786	990	1,200	3,358
Difference[(c)]	0	(46)	(75)	(370)	(463)	(450)	(1,358)

(a) PG&E also adjusted its forecast number of underground miles tracked in MAT 95F. Table 4-2 above.
(b) PG&E-04, p. 4.3-51, Table 4.3-11, lines 5 and 8.
(c) Differences due to rounding.
(d) This table reflects only MAT 08W mileage targets and does not include Community Rebuild (MAT 95) targets as shown in Table 4-2 above in Section 4.1.

Even with this adjustment, PG&E's commitment to reduce the highest risk areas in the HTFD has not changed. As described above, PG&E plans to focus its efforts in this rate case period on undergrounding approximately 2,000 circuit miles of distribution lines in and near the HFTD. Undergrounding 2,000 miles will address up to 20 percent of the cumulative risk in the HFTD. As the undergrounding program progresses, PG&E will continue to mitigate wildfire risk in the HFTD using the portfolio of wildfire mitigation and control programs PG&E describes in this GRC.[1583]

In their Opening Briefs, intervenors raise various recommendations regarding PG&E's original February, 2022 proposal of undergrounding 3,300 miles from 2023-2026. PG&E responded to these recommendations in its Opening Brief, and responds to various new in issues in this Reply Brief. A summary of the intervenors' respective positions and where PG&E responds to the issues follow:

1583 *See* PG&E-04, Ch. 4.0 through Ch. 4.6 for a description of PG&E's wildfire mitigation portfolio (PG&E-04, p. 4-1 to p. 4.6-21). PG&E's wildfire control programs are described throughout PG&E-04 (i.e., Ch. 9 describes PG&E's Vegetation Management program, and Ch. 10 describes PG&E's Inspection program).

Cal Advocates recommends that PG&E focus its underground system hardening on the top 10 percent of risk-ranked circuit segments in HFTD – based on the per-mile risk.[1584] Cal Advocates does not provide a total dollar recommendation, but proposes a graduated unit cost cap for undergrounding that varies according to the risk of circuit segments undergrounded during the rate case period.[1585] PG&E responds to Cal Advocates' recommendation regarding to prioritization in Section 4.2.2.2 of this Reply Brief and to Cal Advocates' recommendation regarding unit cost caps in Section 4.3.1.4.3 of this Reply Brief.

TURN recommends that the Commission authorize PG&E to install a total of 1,800 miles of covered conductor and 200 miles of underground conductor during the rate case period.[1586] As discussed in Section 4.2.2.1 of this Reply Brief, TURN's recommended funding level for permanent risk reduction through underground hardening would leave significant portions of PG&E's HFTD unmitigated. The Commission should not approve TURN's ineffective proposal. Further, the adjustment PG&E is willing to make to its miles comes closer to TURN's total mileage amount but with a higher mix of undergrounding given the greater risk mitigation from it.

AARP recommends that the Commission postpone a decision and authorize one-half of PG&E's original June 30, 2021 forecast for overhead system hardening until multiple other alternatives are more fully evaluated.[1587] PG&E addresses AARP's recommendations in the following sections of PG&E's Opening Brief: Section 4.3.1.1.2 discusses AARP's recommendation regarding postponing a decision on the undergrounding plan and Section 4.3.2.3 discusses funding for overhead line hardening.

1584 Cal Advocates Opening Brief, p. 146.

1585 Cal Advocates Opening Brief, pp. 140-141.

1586 TURN Amended Opening Brief, p. 378.

1587 AARP Opening Brief, pp. 26, 28.

MGRA recommends that PG&E's 10,000 mile undergrounding proposal should be denied in its current form, and that the Commission should instead approve a hardening program relying on covered conductor.[1588] PG&E addressed MGRA's recommendations in the following sections of PG&E's Opening Brief: Section 4.3.1.1.2 (program scope and pace of work) and Section 4.3.14 (unit cost targets).

The California Farm Bureau Federation (CFBF) recommends that the Commission require PG&E to evaluate alternatives such as microgrids and covered conductors.[1589] PG&E explained in its rebuttal testimony that it is not currently forecasting construction of new temporary distribution microgrids from 2023-2028.[1590] The CFBF also raises new issues related to undergrounding costs. PG&E addresses these new issues in Section 4.3.1.6.3 and Section 4.24 of this Reply Brief.

Wild Tree Foundation (Wild Tree or WTF) recommends that the Commission should reject PG&E's request for its undergrounding proposal.[1591] PG&E addressed its undergrounding proposal in Section 4.3.1 of PG&E's Opening Brief.

AT&T[1592] and Comcast[1593] recommend that the Commission deny PG&E's request for wildfire mitigation undergrounding costs. PG&E addressed these and other issues raised by AT&T and Comcast in Section 4.3.1.6 of PG&E's Opening Brief. PG&E addresses other issues raised by telecommunications companies in Section 4.3.1.5 of this Reply Brief.

1588 MGRA Opening Brief, p. 4.

1589 CFBF Opening Brief, p. 16.

1590 PG&E-17, p. 4.3-52, line 22 to p. 4.3-53, line 10.

1591 Wild Tree Opening Brief, p. 21.

1592 AT&T Opening Brief, p. 17.

1593 Comcast Opening Brief, p. 4.

CUE recommends that the Commission authorize PG&E's wildfire system hardening program without any adjustments.[1594] Many of the intervenors who oppose PG&E's proposals raise duplicative objections. CUE, however, provies a unique perspective. PG&E respectfully urges the Commission to consider CUE's recommendation in this proceeding, given CUE's unique position as the only intervenor directly representing the interests of utility employees and workers impacted by this GRC.

PG&E's capital forecast and intervenors' recommended adjustments are summarized below.

TABLE 4-10:
SYSTEM HARDENING UNDERGROUND – PG&E'S MAT 08W ADJUSTED CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS ($000s)

Party	2021	2022	2023	2024	2025	2026
PG&E	$127,654	$491,625	$997,206	$1,288,141	$1,554,386	$2,085,850
Cal Advocates[(a)]	$(95,812)	$(288,060)	$(801,148)			
TURN[(b)]			$(830,318)	$(1,129,932)	$(1,405,445)	$(1,946,793)
AARP[(b)]			$(943,135)	$(1,244,158)	$(1,527,279)	$(2,085,850)
Other[(e)]			$(997,206)	$(1,288,141)	$(1,554,386)	$(2,085,850)
CUE[(d)]	$0	$0	$0	$0	$0	$0

(a) Cal Advocates recommends a unit cost cap for undergrounding that varies according to the risk of circuit segments undergrounded during the rate case period but does not provide a total dollar recommendation. See Cal Advocates Opening Brief, pp. 140-141.

(b) TURN and AARP's recommendations are presented as recommended funding levels as opposed to recommended reductions. PG&E has calculated the recommended reduction by subtracting Parties' recommended funding level for system hardening underground from PG&E's adjusted forecast. PG&E's adjusted forecast amount includes both the 10K underground program and Community Rebuild.

(c) AT&T, Comcast, MGRA and Wild Tree recommend no funding. *See* PG&E-17, WP 4.3-5 to WP 4.3-7.

(d) CUE Opening Brief, p. 14.

For the reasons discussed in PG&E's Opening Brief and in further detail below,[1595] intervenors' recommendations to postpone and/or not fund PG&E's undergrounding program are unsound and should be rejected given the significant wildfire risk PG&E's customers and communities face.

1594 CUE Opening Brief, p. iv.

1595 PG&E Opening Brief, pp. 378-412.

4.3.1.2 Undergrounding Scope

PG&E's testimony describes PG&E's integrated system hardening approach and explains that PG&E will use undergrounding as a preferred option after line removal and remote grid. PG&E's testimony confirms, however, that PG&E will continue to use other mitigations as appropriate.[1596] In their Opening Briefs, intervenors assert PG&E has abandoned its holistic approach to wildfire mitigation in favor of a single program – undergrounding[1597] – or that PG&E has not provided sufficient evidence that it can complete the program as forecast.[1598] These assertions are untrue. PG&E addresses these concerns in the sections below.

4.3.1.2.1 PG&E Is Pursuing A Holistic Approach To Wildfire Risk Management Focused On Undergrounding The Highest Risk Miles In The HFTD

PG&E has been very clear that while undergrounding is the preferred wildfire mitigation approach because it almost entirely eliminates wildfire risk in the highest risk areas of PG&E's HFTD and improves system reliability,[1599] PG&E is utilizing an integrated wildfire mitigation consisting of numerous mitigation activities in addition to undergrounding.[1600] The suite of integrated wildfire mitigation activities includes, among other things, overhead hardening, line removal, remote grids, enhanced automation, vegetation management, and several other related activities.[1601] Further, given the time required to underground distribution lines,[1602] extreme wind and weather events that will continue to threaten the safety of the communities being

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1596 PG&E-04, p. 4.3-6, lines 4-25.

1597 *See* Comcast Opening Brief, p. 2; TURN Amended Opening Brief, p. 378.

1598 See Cal Advocates Opening Brief, p. 128; Comcast Opening Brief, p. iv; TURN Amended Opening Brief, p. 400; Wild Tree Opening Brief, p. 5.

1599 PG&E-04, p. 3-2, lines 27-31.

1600 PG&E-04, p. 3-7, lines 5-22; and p. 3-71 to p. 3-73, Table 3A-1.

1601 PG&E-04, p. 4.3-7, lines 11-17, p. 4.3-53, line 28 to p.4.3.65, line 10.

1602 PG&E-04, p. 4.3-42, Table 4.3-9 is a table showing an approximate duration timeline for an underground project.

served,[1603] construction feasibility challenges,[1604] and the benefits provided by other mitigations such as EPSS, PSPS, situational awareness and emergency response,[1605] PG&E will continue to deploy a balanced portfolio of mitigations to reduce the greatest amount of wildfire risk across the HFTD.

PG&E is committed to implementing a holistic approach to wildfire risk management. Severely restricting or postponing undergrounding, as parties recommend,[1606] puts PG&E's customers and communities at unreasonable risk and should be rejected by the Commission.

4.3.1.2.2 Cal Advocates' Claim That PG&E's Undergrounding Proposal Is Not Properly Supported On The Record Is Wrong

Cal Advocates incorrectly argues that PG&E's forecast is not supported by the evidentiary record, asserting that PG&E's undergrounding mileage proposal is not risk-informed.[1607] As summarized in its Opening Brief,[1608] PG&E provided ample detailed risk analysis in testimony and discovery responses supporting its system hardening program and other risk mitigation and control program forecasts. Indeed, TURN noted that PG&E's risk analysis workpapers provide considerable detail for each risk and are so voluminous that PG&E submitted them for the record on a DVD.[1609] In addition, to support its cost forecasts, PG&E provided recorded and forecast cost information at the planning order level, described its forecast methodologies, and provided working Excel spreadsheets documenting the underlying data and

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1603 PG&E-04, p. 3-2, lines 24-26.

1604 Tr. Vol. 9, 1614:19 to 1615:4, PG&E/McGregor.

1605 PG&E-04, p. 4-1, lines 16-26.

1606 *See* AARP Opening Brief, p. 26; AT&T Opening Brief, p. 17; Comcast Opening Brief, p. iv; MGRA Opening Brief, p. 4; and Wild Tree Opening Brief, p. 3.

1607 Cal Advocates Opening Brief, p. 128.

1608 *See for example*, PG&E-02, Ch. 1 (Enterprise Risk Management testimony and supporting workpapers); PG&E-04, Ch. 3 (Electric Distribution Risk Management testimony and supporting workpapers); PG&E Opening Brief, pp. 25-31 (Enterprise Risk Management), and pp. 365-378 (Electric Distribution Risk Management).

1609 TURN Amended Opening Brief, pp. 55-56.

calculations supporting its cost forecasts. Cal Advocates had access to these materials starting in July 2021 – more than 16 months ago – and cannot now credibly claim that PG&E's showing is not risk-informed or properly supported by evidence on the record.

Cal Advocates further claims that it did not have sufficient time or data to evaluate PG&E's February 2022 capital undergrounding expenditure cost update.[1610] Cal Advocates had access to the same forecast cost data and the same ability to ask for additional information through discovery as all the other parties to this proceeding, consistent with the schedule adopted in the Scoping Memo. Other parties were able to use this time and provide recommendations regarding PG&E's undergrounding proposal; only Cal Advocates submitted testimony based on the superseded forecast. To now claim that PG&E failed to provide sufficient data is not credible and, as such, Cal Advocates' forecast recommendations should not be given any credence.[1611]

4.3.1.3 Work Execution

In testimony, as summarized in its Opening Brief, PG&E described its ability to effectively address undergrounding implementation challenges.[1612] In their Opening Briefs, intervenors raise various new concerns about PG&E's ability to manage long-term execution

1610 Cal Advocates Opening Brief, p. 146.

1611 In Section 4.2.2.1 of its opening brief, Cal Advocates states, "PG&E has not done any cost benefit analysis of its undergrounding proposal," (Cal Advocates Opening Brief, p. 141) and cites to oral testimony from PG&E's risk witness Mr. McGregor to support this claim (Tr. Vol. 9, 1634:21 to 1635:19, McGregor/PG&E). Cal Advocates mis-states Mr. McGregor's testimony. During cross-examination Cal Advocates asks Mr. McGregor about, "the cost implications to ratepayers" for executing underground work and Mr. McGregor responds, "I am not a cost witness. My perspective on this, as PG&E's director of risk management and analytics, is about risk." (*Id.*, at 1635:4-10.) The only discussion of cost from Mr. McGregor comes further in his response when he testifies, "From my perspective, executability involves time, and time unfortunately leads to cost when we're looking at the execution of such a large-scale project." (*Id.*, at 1635:12-16.) Cal Advocates assertion that PG&E has not done any cost benefit analysis of its undergrounding proposal on the basis of Mr. McGregor's testimony is incorrect.

1612 PG&E Opening Brief, pp. 393-402.

issues that may be outside of PG&E's control. PG&E addresses these concerns immediately below.

4.3.1.3.1 PG&E Has Demonstrated Its Ability To Complete A Higher Volume Of Undergrounding Work

PG&E acknowledges that the number of miles PG&E is proposing to underground during the GRC period represents a substantial increase compared to the number of miles completed in recent years.[1613] But it is entirely unsound to conclude that PG&E's undergrounding mileage targets are not achievable simply based on PG&E's past levels of undergrounding when PG&E was not implementing an undergrounding program. Section 4.3.1.3 of PG&E's Opening Brief explains in detail how PG&E is effectively addressing undergrounding implementation challenges. As described in its testimony and Opening Brief,[1614] PG&E has built a robust underground program delivery organization based on international best practices[1615] and onboarded an industry leading engineering firm with substantial expertise in delivering mega-projects as PG&E's program management partner.[1616] Indeed, PG&E is already seeing productivity-related benefits of its undergrounding organization. In 2021, PG&E completed approximately 72 miles[1617] of undergrounding work and anticipates completing more than twice as many miles – at least 175 miles – this year.[1618] Based on this recent history, PG&E has demonstrated its ability to execute a significantly greater number of miles as it scales up its undergrounding delivery organization and will continue to do so to meet the targets established throughout the rate case period.

1613 *See* Cal Advocates Opening Brief, pp. 146-147; CFBF Opening Brief, p. 6; Comcast Opening Brief, p. 14; TURN Amended Opening Brief, pp. 400-401; and Wild Tree Opening Brief, p. 5.

1614 PG&E Opening Brief, p. 393-401.

1615 PG&E-17, p. 4.3-24, line 25 to p. 4.3-25, line 7.

1616 PG&E-17, p. 4.3-33, lines 13-15.

1617 Tr. Vol. 8, 1547:22-24, PG&E/Pender.

1618 Tr. Vol. 8, 1549:10-11, PG&E/Martin.

4.3.1.3.2 Parties' Concerns Related To Longer-Term Execution Issues Are Unfounded

Parties raise concerns about PG&E's ability to execute its undergrounding work due to various external factors outside of PG&E's control, such as construction permits,[1619] supply chain challenges, or endangered species/protected plants that may be present on project sites and cause delays.[1620] PG&E is proactively addressing these types of program risks. In June 2022, PG&E held a supplier summit to identify additional civil, electrical, program management, environmental land, permitting, materials, equipment, and other support resources.[1621] In addition, the undergrounding Project Management Organization (PMO) is implementing a streamlined delivery process focused on identifying and implementing efficiencies in scoping, estimating, dependency management (permitting, land and environment, materials, resourcing, scheduling) and construction. The process improvements will provide significant efficiency benefits by pulling activities forward and performing them in parallel rather than sequentially. The current process to deliver undergrounding work takes approximately 19-36 months. Through targeted improvements, PG&E anticipates this process will be reduced to 12-24 months.[1622]

While PG&E is prioritizing undergrounding the highest risk circuits in the HFTD, PG&E is cognizant of other factors that will influence the selection and timing of certain locations for undergrounding and must be carefully managed. PG&E is actively working to address these challenges. For example, the environmental permitting process for underground work where a contiguous path of ground disturbance is required, could involve sensitive areas such as waterways or cultural resources. Undergrounding through these types of sensitive areas is more complex than crossing through them with overhead powerlines. To mitigate risks and issues

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1619 Comcast Opening Brief, p. 16.

1620 CFBF Opening Brief, pp. 9-10.

1621 PG&E-17, p. 4.3-28, lines 11-14.

1622 PG&E-17, p. 4.3-25, lines 8-19.

associated with permitting, land rights, and working in these areas, PG&E has begun and will continue to engage key agencies, cities, counties, tribes, and other stakeholders, and will deploy construction methodologies that mitigate disturbances.[1623]

4.3.1.4 Undergrounding Program Costs

PG&E demonstrated in its Opening Brief that its unit cost targets and program costs are reasonable and achievable and that it has identified opportunities to reduce construction costs.[1624] In their Opening Briefs, Cal Advocates and TURN raise new concerns about PG&E's forecasts. PG&E addresses these issues below.

4.3.1.4.1 PG&E's Forecast Unit Costs For Undergrounding Work

Table 4-11 below shows PG&E's adjusted December 2022 average unit cost forecast for undergrounding from 2023-2026. PG&E's unit cost forecast remains unchanged between its rebuttal and adjusted forecast.

TABLE 4-11:
SYSTEM HARDENING UNDERGROUND –
PG&E'S ORIGINAL AND ADJUSTED AVERAGE UNIT COST FORECAST(a) ($MILLIONS)

PG&E's Unit Cost Forecast	2023	2024	2025	2026	Average 2023-2026
Adjusted Forecast	$3.26	$3.13	$2.96	$2.78	$2.97
Rebuttal Forecast	$3.26	$3.13	$2.96	$2.78	$2.97
(a) Differences due to rounding.					

4.3.1.4.2 PG&E's Undergrounding Proposal Is Cost-Effective In Delivering The Maximum Amount Of Risk Reduction In The Highest Risk Areas Of The HFTD

TURN argues that its system hardening proposal is more cost effective from a risk reduction perspective than PG&E's proposal, asserting that PG&E's undergrounding proposal to eliminate 33 percent of wildfire risk costs more than TURN's hybrid system hardening overhead and undergrounding proposal to eliminate 18 percent of risk. In support, TURN states:

1623 PG&E-04, p. 4.3-35, lines 8-18.

1624 PG&E Opening Brief, pp. 402-405.

> First, PG&E emphasizes that its system hardening plan for this rate case cycle, which focuses on undergrounding, eliminates 33% of the wildfire risk, while TURN's system hardening rate case proposal, which emphasizes covered conductor, would eliminate only 18% of the wildfire risk. TURN did not contest this analysis … .[1625]
>
> * * *
>
> A simplistic comparison of these aggregate numbers indicates that TURN's proposal reduces more than 50% of the wildfire risk amount (18/33) for about 20% of the cost (2.1/10.37), thus demonstrating that TURN's proposal is much more cost effective.[1626]

PG&E does not disagree with TURN's simplistic arithmetic but disagrees with TURN's conclusions regarding the overall effectiveness of its proposal for four reasons.

First, PG&E's proposal virtually eliminates the wildfire risk in the locations where undergrounding is installed, whereas TURN's proposal includes both underground and overhead hardening – a less effective method wildfire risk reduction. In fact, TURN's proposal leaves 22 percent of the risk on the system in the HFTD. This 22 percent is important. The work PG&E is proposing in this GRC is the highest risk work in and near the HFTD. The Commission should not adopt an ineffective strategy that leaves 22 percent risk in the highest risk locations on the system. In urging the Commission to adopt a mitigation measure that leaves significant portions of the system vulnerable to wildfire risk, TURN effectively asks the Commission to adopt a viewpoint that no more can be done or should be done to prevent catastrophic wildfires, reflecting a bleak outlook for northern California in contrast to PG&E's proposal.

Second, covered conductor can be destroyed by wildfire. If PG&E were to install covered conductor in the highest risk areas of the HFTD, there is a risk that assets could be damaged or destroyed in a wildfire caused by other ignition sources, requiring them to be hardened a second time at additional cost to customers.

Third, TURN's analysis estimates the undergrounding costs of its alternative proposal based on PG&E's undergrounding unit cost. PG&E's unit cost is based on completing

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1625 TURN Amended Opening Brief, pp. 388-389 (fns. omitted).

1626 TURN Amended Opening Brief, p. 389 (fn. omitted).

approximately 2,000 miles during the GRC period where TURN's proposal assumes only 200 miles. It is unreasonable to assume that PG&E could achieve its forecast unit cost only installing 200 miles. The undergrounding costs used in TURN's analysis are likely understated.

Fourth, TURN analysis is further skewed because it substitutes its own estimated unit costs for overhead hardening in place of PG&E's forecast unit cost.[1627] PG&E disagrees with TURN's overhead hardening unit cost proposal and addresses the flaws with TURN's assumptions in Section 4.3.2.2.1 of PG&E's Opening Brief. Because TURN's unit cost proposal for overhead hardening is flawed, the Commission should ignore TURN's cost-effectiveness analysis using TURN's assumed system hardening unit costs.

In sum, TURN's overhead-focused proposal does not permanently address wildfire risks; is vulnerable to wildfires caused by other non-electric ignition sources; and relies on manipulated calculations that deflate overhead costs and increase underground costs to derive a false cost-effectiveness comparison.

4.3.1.4.3 Cal Advocates' And TURN's Proposed Unit Cost Cap For Undergrounding Is Unnecessary

Cal Advocates proposes a graduated unit cost cap structure for undergrounding and overhead hardening work that would vary according to the risk ranking of circuit segments.[1628] TURN proposes that the Commission establish a reasonableness cost cap on undergrounding unit costs of $3.0 million per mile.[1629] Cal Advocates' and TURN's proposal to set a cost cap for system hardening work is unnecessary and unwarranted. While PG&E is confident that it can meet the unit cost targets forecast in this GRC, there are situations that can increase costs that are outside of PG&E's control and where the costs would still be reasonable. PG&E records its costs in a two-way balancing account, the Wildfire Mitigation Balancing Account (WMBA). As

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1627 TURN Amended Opening Brief, p. 389.

1628 Cal Advocates Opening Brief, p. 140.

1629 TURN Amended Opening Brief, Summary of Recommendations, p. xx.

discussed in PG&E's Opening Brief, Section 4.24.1, the WMBA provides cost protections for customers. Customers pay only for the actual work performed and if PG&E's forecasts exceed its actual costs, the difference in cost will be returned to customers. The WMBA is also appropriate in that the work PG&E will conduct will be established through the annual WMPs as approved by OEIS, and may vary from the work forecast in this proceeding. The WMBA is a transparent mechanism. The Commission and intervenors can review PG&E's wildfire risk mitigation forecast for the WMBA through the GRC and any of PG&E's actual recorded costs above its forecast through a combination of the Tier 2 advice letter process (for costs exceeding the WMBA forecast up to the reasonableness threshold proposed by PG&E) and reasonableness review (for costs incurred above the reasonableness threshold). Cal Advocates' and TURN's proposed cost cap is unnecessary.

4.3.1.4.4 TURN's Claim That PG&E's Forecast Cost For Undergrounding Is Too Low Is Incorrect

TURN claims that PG&E downplays the relative difference between the costs of undergrounding and covered conductor by forecasting too low a figure for undergrounding. According to TURN, the correct metric to use when comparing the costs of undergrounding to the cost of installing covered conductor, is the number of overhead circuit miles that are de-energized.[1630]

TURN's position on this issue is incorrect. When PG&E removes an overhead line, it generally installs a longer section of underground line primarily due to challenges with topography.[1631] While there is not an exact correlation between the number of overhead miles removed and underground miles installed, PG&E generally uses a ratio of 1.25 underground miles installed for each overhead line mile removed. The RSE for undergrounding accounts for the difference between the number of overhead miles de-energized and the number of miles

1630 TURN Amended Opening Brief, p. 410.

1631 TURN Amended Opening Brief, p. 410.

relocated underground. The RSE calculation recognizes for that every 1 overhead mile removed, approximately 1.25 miles will be relocated underground. The expected risk reduction is factored into the risk model and the amount of risk on the system is already accounted for in the difference between the number of overhead miles removed and number of miles relocated underground.[1632] Because the risk model accounts for the difference between the overhead lines removed and underground lines installed, TURN's claim that the number of de-energized overhead circuit miles is the best metric to use when evaluating system hardening costs[1633] is wrong. PG&E's undergrounding forecast does not need to be adjusted as TURN suggests[1634] and is the correct metric to evaluate and compare against other mitigation measures.

4.3.1.5 Issued Raised By Telecommunications Providers

PG&E addressed the issues raised by telecommunications providers in PG&E's Opening Brief.[1635] PG&E explained that the telecommunications providers are under no obligation to participate in PG&E's undergrounding program, there are well established contractual procedures that govern PG&E and the telecommunications providers respective legal rights, and PG&E is coordinating with the telecommunications providers as it implements undergrounding work.

In their Opening Briefs, telecommunications providers identify new issues related to cost recovery for undergrounding work and provisions in the Northern California Joint Pole Association (NCJPA) handbook. PG&E addresses these new issues below.

1632 PG&E-17, p. 3-19, lines 1-15.

1633 TURN Amended Opening Brief, p. 410.

1634 TURN Amended Opening Brief, p. 411.

1635 PG&E Opening Brief, pp. 405-412.

4.3.1.5.1 AT&T's Recommendation To Institute A Rulemaking Should Be Denied

AT&T recommends that the Commission institute a rulemaking to address regulatory uncertainties related to the impact of undergrounding communications facilities.[1636] A rulemaking proceeding is not necessary. Many undergrounding activities do not involve or impact telecommunication providers in any way. To the extent undergrounding activities do impact them, PG&E is actively coordinating with the telecommunications providers as PG&E plans and implements undergrounding work.[1637] In addition, agreements and other documents (such as the NCJPA handbook) governing business relationships between and among PG&E and the telecommunications providers are in place to address many issues and PG&E is committed to working with the telecommunications providers to find solutions to unresolved issues.

Further, while PG&E continues to develop its comprehensive strategy to address issues related to the telecommunications providers, it is critical that the undergrounding work proceed. PG&E acknowledges that there may be issues still to be addressed for certain projects and uncertainty in some areas of the undergrounding program that may impact telecommunication providers. However, instituting a rulemaking after the program has already started and while PG&E continues to coordinate with telecommunication providers in accordance with existing agreements, would detrimentally impact the undergrounding program and allow increased wildfire risk to remain unmitigated, to the extent PG&E were required to abandon or pause certain activities until a decision was issued in the proceeding.

In its Opening Brief, Comcast argues that if the Commission decides that attachers should pay a portion of PG&E's undergrounding costs, the amount paid should be capped at PG&E's true marginal costs to accommodate other occupants in a joint trench.[1638] Comcast recommends that the Commission should hold a workshop to develop the methodology PG&E

1636 AT&T Opening Brief, p. 17.

1637 PG&E Opening Brief, p. 411.

1638 Comcast Opening Brief, pp. 27-28.

and other stakeholders will use to determine PG&E's actual marginal costs.[1639] PG&E generally agrees that attachers should only be required to pay costs necessary to accommodate other occupants in a joint trench. PG&E also does not object to the concept of Commission workshops, but notes that formal workshops are unnecessary as these type of issues are frequently addressed among utilities without controversy.

4.3.1.6 Non-Financial Recommendations

In Section 4.3.1.7 of PG&E's Opening Brief, PG&E addressed several non-financial recommendations raised by intervenors in their testimony.[1640] In this section, PG&E responds to various new non-financial recommendations raised by intervenors in their Opening Briefs. As discussed in further detail below, PG&E is either already complying with the recommendation, will be complying with the recommendation, or the recommendation is unnecessary or will not add value to the Commission's ongoing evaluation or monitoring of PG&E's undergrounding program.

4.3.1.6.1 Recommendation 1: Cal Advocates' Recommendation Requiring PG&E To Focus Undergrounding On The Top Ten Percent Of Risk-Ranked Circuit Segments

Cal Advocates recommends that the Commission require PG&E to focus any undergrounding on the top 10 percent of risk-ranked circuit segments within the HFTDs and include a cost benefit analysis that considers alternatives to undergrounding or some combination of undergrounding and such alternatives. PG&E addresses this issue in Section 4.2.2.2 above. Briefly summarized here, the recommendation is premature. The Commission has issued a proposed decision[1641] directing IOUs to implement a newly described Cost-Benefit Approach in

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1639 Comcast Opening Brief, p. 28.

1640 PG&E Opening Brief, pp. 412-419.

1641 R.20-07-013, *Ph. II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in D.18-12-014 and Directing Environmental and Social Justice Pilots* (Nov. 3, 2022) ("Proposed Decision re RDF Modifications" or "Proposed Decision").

their next respective GRC cycles, beginning with PG&E's 2024 RAMP.[1642] Requiring another or different cost benefit prior to PG&E's 2024 RAMP is unnecessary.

Cal Advocates also recommends that the Commission should require that any approval of PG&E's undergrounding be risk-informed and matched to PG&E's resource capability to complete such projects.[1643] PG&E demonstrates that its undergrounding proposal is risk informed in Section 4.2 above. Cal Advocates ignores ample evidence presented by PG&E regarding its risk analyses supporting PG&E's decision making.

4.3.1.6.2 Recommendation 2: Cal Advocates' Proposed New Reporting Requirements

Cal Advocates recommended five different reporting requirements in its opening testimony that PG&E responded to in Section 4.3.1.7.1 of PG&E's Opening Brief.[1644] Cal Advocates now makes one additional reporting-requirement recommendation that the Commission should require PG&E to provide the Safety Policy Division (SPD) a complete list of planned system hardening projects, with the corresponding circuit miles as adjusted (e.g., 10 miles of overhead conductor removed and replaced with 12 miles of underground conductor), for each year during the GRC period if the Commission approves PG&E's proposal. In addition, Cal Advocates recommends that PG&E should provide GIS data of the planned and executed system hardening projects that year, as well as the permits and GIS data for the proposed system hardening work for the following year to SPD and parties upon request.[1645]

PG&E already provides information about planned system hardening projects, including GIS data, to the OEIS through the WMP process. The number of overhead conductor miles removed does not impact the selection of project miles or otherwise influence the

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1642 Proposed Decision re RDF Modifications, p. 22. *See also id*., pp. 56-57, OP 2.

1643 Cal Advocates Opening Brief, p. 137.

1644 PG&E Opening Brief, pp. 415-416.

1645 Cal Advocates Opening Brief, p. 137.

undergrounding project. It is unclear why Cal Advocates believes the Commission needs this information to evaluate underground hardening projects. It is also unclear why the Commission or parties need PG&E's permits for system hardening work planned for the following year. The Commission should deny Cal Advocates' unnecessary request for additional reporting.

4.3.1.6.3 Recommendation 3: California Farm Bureau Federation Recommendations For Undergrounding Program Limits And Guarantees

The CFBF makes three recommendations:

1. Limits can and should be established to prevent a new megaproject in the GRC cycle or sooner that will only further multiply skyrocketing rates. By placing a limiter on the rate at which revenue requirements can increase, PG&E will be incentivized to seek grants and other federal and state funding such that there is not total reliance on ratepayers to fund all activities of the utility.[1646]
2. Quantify and guarantee PG&E's proposed "long term" savings by choosing to underground rather than other wildfire mitigation technologies.[1647]
3. Limits should be placed on the cost per mile for undergrounding as well as time limits that PG&E will be required to complete the projects. Should PG&E exceed those limits they will do so on their own dime. That approach will not excuse performance but provide an adequate measurement against the promises PG&E has made in this proceeding and give PG&E equal "skin in the game."[1648]

PG&E objects to these recommendations.

First, the Commission should not limit the type of project PG&E, or any other utility, can forecast in its GRC. The objective of the regulatory process is for the Commission to evaluate the utility's proposals and make determinations about them based on the merit of the project – regardless of size or type of project. CFBF is exercising its right to evaluate PG&E's undergrounding project in this GRC which is the how the process is meant to work. There is no basis for the Commission to limit the type of proposal a utility can put forward in its rate case.

1646 CFBF Opening Brief, p. 17.

1647 CFBF Opening Brief, p. 17.

1648 CFBF Opening Brief, pp. 16-17.

CFBF's proposal would prejudge the reasonableness of future proposals before they are presented.

Next, PG&E is proposing to underground distribution lines to reduce as much risk as possible in and near the HFTD.[1649] Long-term savings is a benefit of undergrounding but not a driver of the program. PG&E's undergrounding program should be evaluated based on the program's effectiveness at reducing risk and mitigating wildfires. While long-term savings, increased reliability, reduced reliance on power shut-offs, and other benefits of the undergrounding program[1650] are important, they are not as important as reducing wildfire risk. Requiring PG&E to somehow quantify and guarantee savings that depend upon various factors and will likely materialize only after decades have passed[1651] is unrealistic and should not be adopted.

Finally, as discussed in Section 4.3.1.4.3 above, while PG&E is confident that it can meet the unit cost targets it is forecasting in this GRC, there are situations that could increase costs that are outside of PG&E's control. Because PG&E records its costs in a two-way balancing account, customers are protected because they pay only for the actual work performed and if PG&E's forecasts are higher than its actual costs, the difference in cost is returned to customers. The Commission and intervenors can review PG&E's WMBA forecasts and recorded costs through the GRC, the Tier 2 advice letter process, and in after-the-fact reasonableness review applications. Similarly, the CFBF's proposal to set time limits to complete underground projects is unreasonable and should not be approved. PG&E works hard to meet or exceed project schedules but there are many factors outside of PG&E's control that can impact a project

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1649 PG&E-04, p. 3-2, lines 20-24.

1650 PG&E-04, p. 4.3-10, line 17 to p. 4.3-12, line 10.

1651 PG&E-04, p. 4.3-10, line 30 to p. 4.3-11, line 4.

schedule, such as permitting feasibility, accessibility, availability of construction materials, coordination with joint pole/joint trench tenants, and environmental considerations.[1652]

4.3.2 Overhead System Hardening

In Section 4.3.1, PG&E discusses its adjusted system hardening underground forecast costs and miles. PG&E also revised the costs and miles for its system hardening overhead program in 2023 and 2024. Tables 4-12 and 4-13 below compare PG&E's original forecast costs and miles to the revised forecast costs and miles. The minor adjustments that PG&E made to its overhead system hardening program does not change the positions discussed in PG&E's Opening Brief or in this Reply Brief responding to intervenors' recommendations.

**TABLE 4-12:
SYSTEM HARDENING OVERHEAD
PG&E'S ORIGINAL AND ADJUSTED CAPITAL FORECAST- MAT 08W ($000S)**

PG&E's Forecast	2021	2022	2023	2024	2025	2026	Total 2023-2026
Revised Forecast	$288,000	$366,000	$171,714	$122,260	$83,918	$86,402	$464,295
Original Forecast[(a)]	$288,000	$366,000	$265,377	$81,507	$83,918	$86,402	$517,204
Difference	$0	$0	$(93,662)	$40,753	$0	$0	$(52,909)
(a) PG&E-04, p. 4.3-51, Table 4.3-11, line 1.							

**TABLE 4-13:
SYSTEM HARDENING OVERHEAD
PG&E'S ORIGINAL AND ADJUSTED OVERHEAD MILES FORECAST – MAT 08W ($000S)**

PG&E's Forecast Miles	2021	2022	2023	2024	2025	2026	Total 2023-2026
Revised Proposal	180	305	110	75	50	50	285
Original Proposal [(a)]	180	305	170	50	50	50	320
Difference	0	0	(60)	25	0	0	(35)
(a) PG&E-04, p. 4.3-51, Table 4.3-11, line 2.							

PG&E summarizes parties' positions relative to PG&E's revised system hardening overhead forecast in Table 4-14 below.

1652 PG&E-04, p. 4.3-32, line 14 to p. 4.3-33, line 8.

TABLE 4-14:
SYSTEM HARDENING OVERHEAD – PG&E'S ADJUSTED CAPITAL FORECAST AND PARTIES RECOMMENDED REDUCTIONS ($000S)

Party	2021	2022	2023	2024	2025	2026
PG&E	$288,000	$366,000	$171,714	$122,260	$83,918	$86,402
Cal Advocates[(a)]	$(167,572)	$0	$0			
TURN[(a)]			$186,486	$245,611	$293,886	$301,603
AARP[(a)]			$149,108	$189,503	$228,448	$226,572
(a) Cal Advocates, TURN, and AARP's recommendations are presented as recommended funding levels as opposed to recommended reductions. PG&E has recalculated the recommended reduction by subtracting Parties' recommended funding level for system hardening overhead from PG&E's adjusted forecast.						

Cal Advocates did not raise any new issues in its Opening Brief regarding PG&E's System Hardening Overhead forecast. Cal Advocates used PG&E's 2021 recorded capital expenditures for overhead system hardening for its recommended funding level. Cal Advocates further states that it accepts PG&E's new updated 2022 and 2023 capital expenditure forecasts of $366.0 million in 2022 and $265.4 million in 2023, with zero adjustments, because the updated forecasts are significantly lower than PG&E's original 2022 and 2023 forecasts and the unit costs align well with recent recorded costs.[1653] PG&E addressed Cal Advocates' recommendations in Section 4.3.1.7.1 of PG&E's Opening Brief.

TURN recommends increased deployment of the overhead program coupled with reduced deployment of undergrounding, which would result in the installation of 1,800 miles of covered conductor over the GRC period. This proposal would result in an increase to PG&E's forecast for overhead system hardening each year from 2023-2026 by the amount shown in Table 4-14 above, with a total increase to PG&E's forecast of $974.7 million over this period.[1654] TURN raises several issues that PG&E discusses in Section 4.3.2.1 below.

AARP did not raise any new issues in its Opening Brief related to PG&E's overhead hardening forecast. AARP recommends that the Commission postpone a decision on PG&E's

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1653 Cal Advocates Opening Brief, pp. 146-147.

1654 TURN Amended Opening Brief, p. 415. Note, TURN's recommended funding level is based on PG&E's rebuttal forecast and does not account for the adjustments to PG&E's forecast costs and miles shown in Tables 4-12 and 4-13 above. Table 4-14 shows TURN's recommended funding level based on PG&E's adjusted forecast.

undergrounding proposal and authorize half of the originally-requested capital for overhead line hardening. This proposal would result in an increase to PG&E's forecast for overhead hardening each year from 2023-2026, with a total increase to PG&E's forecast of $740.7 million over this period.[1655] PG&E addressed AARP's recommendations in Section 4.3.1.7.2 of PG&E's Opening Brief.

4.3.2.1 Responding To Issues Raised by TURN Related to PG&E's System Hardening Overhead Program

TURN raises four issues in its Opening Brief related to PG&E's System Hardening Overhead program. PG&E addressed each of these issues in its Opening Brief and/or this Reply Brief.

1. TURN argues that covered conductor (system hardening overhead) is more cost effective at reducing ignition risk, citing the difference in RSE values between underground and overhead hardening.[1656] PG&E responds to this issue in Section 4.2.6 above.
2. TURN claims that PG&E attempts to obfuscate the cost effectiveness issue with numbers and analyses that prove an "apples to oranges" comparison.[1657] PG&E addresses this issue in Section 4.3.1.4.2 above.
3. TURN states that covered conductor is more affordable when used in conjunction with other mitigation measures.[1658] PG&E addresses TURN's discussion about overhead hardening risk mitigation effectiveness in Section 4.2.2.3 above. PG&E describes is comprehensive wildfire mitigation strategy that relies on a suite of mitigations to reduce wildfire risk in its opening testimony.[1659]

1655 AARP Opening Brief, pp. 28-29. Note, AARP's recommended funding level is based on PG&E's rebuttal forecast and does not account for the adjustments to PG&E's revised forecast costs and miles shown in Tables 4-12 and 4-13 above. Table 4-14 shows AARP's recommended funding level based on PG&E's adjusted forecast.

1656 TURN Amended Opening Brief, pp. 385-386.

1657 TURN Amended Opening Brief, p. 388.

1658 TURN Amended Opening Brief, p. 392.

1659 PG&E-04, p. 3-2, lines 14-26.

4. TURN argues that the Commission should adopt its forecast unit cost for covered conductor.[1660] PG&E addressed this issue in Sections 4.3.2.2.1, 4.3.2.2.2, and 4.3.2.2.3 of its Opening Brief.

4.4 Other Community Wildfire Risk Mitigations

The Commission should approve PG&E's TY 2023 expense forecast for Other Community Wildfire Risk Mitigations presented as: (1) $370.565 million in rebuttal testimony; and (2) $404.834 million in the JCE with the September escalation adjustment.[1661]

The Commission should also approve PG&E's capital forecast for Other Community Wildfire Risk Mitigations presented as: (1) $142.186 million in 2021, $130.453 million in 2022, $111.278 million in 2023, $99.969 million in 2024, $102.498 million in 2025, and $105.853 million in 2026 in rebuttal testimony; and (2) $146.574 million in 2021, $144.531 million in 2022, and $128.081 million in 2023, $118.054 million in 2024, $120.805 million in 2025, and $122.285 million in 2026 in the JCE with the September escalation adjustment.[1662] PG&E did not segregate the forecasts for the individual Other Community Wildfire Risk Mitigations in the JCE.

The activities comprising Other Community 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). In their Opening Briefs, Cal Advocates and TURN oppose certain portions of PG&E's forecasts for PSPS Operations; Enhanced Automation and PSPS Impact Mitigations; and EPSS. In the sections below, PG&E addresses their contentions.

1660 TURN Amended Opening Brief, pp. 417-422.

1661 PG&E-64, p. 3-2, Table 3A-1, lines 51-57, Column, "PG&E (with Sept 6 Non-Labor Escalation Adjustment)."

1662 PG&E-67, WP-2, lines "[Exhibit 4, Chapter] 4," MWCs 09, 21, 48, 49, 2A and 2F.

4.4.1 Public Safety Power Shutoff Operations

4.4.1.1 PG&E's Forecast For PSPS Events (MWC AB) Is Reasonable

PG&E's TY 2023 expense forecast for PSPS Events (MWC AB) presented in rebuttal testimony is $115.266 million.[1663] In their Opening Briefs, Cal Advocates and TURN recommend forecast reductions based on recent progress made by PG&E in reducing the scope and impact of PSPS events, and their belief that as a result of that progress, PSPS costs in 2023 and future years will be lower than in prior years.[1664] Cal Advocates also adds a new argument that AB 2083 (enacted in September 2022) prohibits PG&E from including 2019 costs to develop the PSPS forecast.[1665] The Commission should reject Cal Advocates' and TURN's recommendations as they fail to understand important cost-drivers and do not account for the most-recent information regarding the likely scope and impact of future PSPS events. In addition, their recommended forecasting methodologies are flawed. PG&E addresses these two issues below.

4.4.1.1.1 PG&E's GRC Forecast For PSPS Is Conservative Based On Changes Being Made To PSPS Decision Making Criteria Referenced In The 2021 Wildfire Mitigation Plan

Both Cal Advocates and TURN point to 2019, the first year of PSPS recorded costs, as an anomalous year that should not be factored into PG&E's PSPS forecast due to various improvements has made to PSPS in recent years. Although the scope of PSPS events decreased from 2019 to 2020, that one-year decrease is not a proper basis to reduce PG&E's forecast, because recent updates to PSPS decision-making criteria may drive an expansion in PSPS scope in future years.[1666] PG&E explained in rebuttal testimony that although it used improved scoping techniques and PSPS mitigation strategies (e.g., remote grid) to reduce the number of

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1663 PG&E-17, p. 4.2-3, Table 4.2-1, line 2.

1664 Cal Advocates Opening Brief, p. 151; TURN Amended Opening Brief, p. 423; CALPA-04, p. 11, lines 13-15; p. 12, line 19 to p. 13, line 7; TURN-11, p. 54, lines 5-7.

1665 Cal Advocates Opening Brief, pp. 149-152.

1666 PG&E-17, p. 4.2-9, lines 21-25.

customers impacted by PSPS events,[1667] PG&E continued to evaluate its PSPS decision-making model and is in the process of including additional factors that may drive an expansion of PSPS events and associated costs in future years.[1668] Specifically, PG&E has incorporated asset health as well as the presence of known, high-risk vegetation conditions adjacent to powerlines into its PSPS decision-making model.[1669] Based on PG&E's initial update of studies of 10 years of weather data from 2011-2020 and incorporation of the potential impact of proposed vegetation criteria to be used in the PSPS forecasting model, PG&E increased the number of anticipated PSPS events per year from three events to five events in its 2021 WMP, with a projected customer impact higher than PG&E's 2023 GRC forecast for PSPS.[1670]

While PG&E is certainly making efforts to limit the number of customers impacted by a PSPS event, the 2023 GRC PSPS forecast remains conservative in comparison to the 2021 WMP. Because the GRC forecast is likely low, not high, the Commission should not adopt Cal Advocates' and TURN's proposed adjustments that will further reduce necessary funding for PG&E's activities (inspecting power lines) prior to restoring power to customers following a PSPS event.

4.4.1.1.2 Cal Advocates' And TURN's Recommended Methods For Forecasting PSPS Event Costs Are Flawed

Cal Advocates developed its PSPS event forecast by removing 2019 costs and assuming the number of customers impacted is the same as occurred 2021.[1671] TURN's proposed method for forecasting PSPS event costs: (1) recommends the average number of customers per event in 2021 be the starting point to forecast TY 2023 costs; (2) incorporates expected improvements in PSPS scope due to deployment of sectionalization devices in 2022 and 2023; and

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1667 PG&E-04, p. 4.2-9, lines 16-18.

1668 PG&E-04, p. 4.2-9, lines 27-29.

1669 PG&E-17, p. 4.2-9, lines 27-29.

1670 PG&E-04, p. 4.2-20, lines 3-21.

1671 Cal Advocates Opening Brief, p. 151; CALPA-04, p. 14, lines 3-7.

(3) incorporates the expected size (number of customers) of each PSPS event into a regression equation to forecast TY 2023 costs.[1672] These are not valid forecast adjustments proposals.

As a threshold matter, Cal Advocates' exclusion of 2019 costs from the forecast, and TURN's recommendation to use 2021 alone as a starting point for the forecast with additional selective adjustments, both appear to arbitrarily narrow the cost-information and data considered solely to derive a lower forecast. The Commission should reject outcome-driven forecasting methodologies.[1673]

Discussing a Commission decision finding certain 2019 PSPS activities unreasonable, Cal Advocates appears to reason that under AB 2083,[1674] which prohibits a utility from recovering through rates the costs arising from a fine or penalty, PG&E is now prohibited from developing a PSPS forecast based in any way upon 2019 costs. Cal Advocates' recommendation to exclude of 2019 data based on AB 2083 is an unsound legal application of that statute. The new law applies to recovery of fines or penalties, not the use of actual recorded costs as data to develop a GRC forecast. Although the Commission found certain 2019 PSPS implementation deficiencies by PG&E, the actual 2019 costs are nevertheless relevant to forecast future costs, particularly given that they are part of a two-year 2019-2020 average that smooths out cost variations – both low and high. Using only a one-year data point as suggested by Cal Advocates would zero out costs that are known not be zero, thus skewing the forecast.

On a related note, TURN argues that PG&E's updated modeling of possible PSPS expansion is insufficient to support an increased forecast.[1675] TURN's argument misses the

1672 TURN-11, p. 54, line 17 to p. 55, line 5.

1673 See, e.g., D.20-07-038, p. 8 (finding that a party challenging a utility's forecast had an affirmative duty to establish why the utility's proposed methodology was unreasonable and that this burden is not met where the challenging party "merely isolated the data that it liked and asked that we focus solely on that period of time. That does not prove it was unreasonable or unlawful for us to prefer to set costs using a broader period of time that offered more information").

1674 Cal Advocates Opening Brief, pp. 149-151.

1675 TURN Amended Opening Brief, pp. 425-426.

point. PG&E is not using this information as a basis for increasing the forecast. Rather, PG&E presented this information to demonstrate that its current GRC forecast is actually conservatively low and should not be further reduced based upon selective use of cost information and other data.

The thrust of Cal Advocates' and TURN's recommendations is that 2019 and 2020 cost-information and other data is irrelevant and should not inform the PSPS forecast. This is faulty reasoning given the inherent variability in extreme-weather-caused PSPS events and evolving PSPS protocols. To demonstrate the fallacy of Cal Advocates' and TURN's selective assumptions, PG&E analyzed how the current PSPS decision-making protocols would have impacted past events, re-evaluating past 2019-2021 weather events using the 2019, 2020, and current protocols. The analysis shows that while most historical PSPS events would have had smaller scope if the current 2021 protocol guidance had been applied, there are exceptions, and certain PSPS events may have been larger in scope under PG&E's current PSPS protocols. Additionally, some smaller PSPS events (e.g., the September 20, 2021 event) would only have been initiated under the current protocols and would not be scoped using either the 2019 or 2020 protocols.[1676] Considering these factors, the Commission should determine that a forecast based on 2019-2020 average recorded costs for PSPS events multiplied by a reasonable number of expected events (just 3 with an additional potential/borderline event per year) is a reasonable forecast approach, particularly when that forecast is conservatively low in comparison to the 2021 WMP, as discussed above.

4.4.1.2 PG&E's Capital Forecast For Public Safety Power Shutoff – Field Ops Tech Capital (MWC 21) Is Reasonable

PG&E's capital expenditures forecast for PSPS – Field Ops Tech Capital (MWC 21) presented in rebuttal testimony is $3.084 million in 2021, $3.237 million in 2022, and

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1676 PG&E's 2022 Wildfire Mitigation Plan Update - Revised, OEIS Docket #2022-WMP (July 26, 2022), p. 987.

$0.262 million in 2023.[1677] Cal Advocates recommends that PG&E's 2021 capital forecast should be replaced with 2021 annualized capital spending.[1678] Cal Advocates recommends an additional reduction of $0.9 million in 2022,[1679] based solely on its assertion that the 2022 forecast should be equal to the 2021 recorded expenditures.[1680] Cal Advocates' reasoning for reducing the 2022 forecast does not make sense and is arbitrary. Cal Advocates does not analyze the specific program or any difference in the work forecast for different years or provide any explanation why they should be equal. Accordingly, there is no basis for reducing PG&E's 2022 forecast to 2021 levels.

4.4.2 Enhanced Automation And PSPS Impact Mitigations

4.4.2.1 PG&E's Capital Forecast For Expulsion Fuse Replacement Program (MAT 2AP) Is Reasonable

PG&E's capital forecasts for the Expulsion Fuse Replacement Program (MAT 2AP) are $15.125 million in 2021, $15.388 million in 2022, $15.752 million in 2023, $16.257 million in 2024, $16.777 million in 2025, and $17.314 million in 2026.[1681]

In its Opening Brief, Cal Advocates recommends a combined 2021-2023 forecast of $23.2 million, about 50% of PG&E's forecast over the same period.[1682] In particular, Cal Advocates recalculates PG&E's 2022 and 2023 forecast by multiplying the number of forecast units each year by PG&E's 2021 recorded unit cost, which Cal Advocates calculated by dividing 2021 recorded costs by number of units installed.[1683]

1677 PG&E-17, p. 2-5, Table 2-2, line 2 (2021); p. 2-6, Table 2-3, line 2 (2022); p. 2-7, Table 2-4, line 2 (2023).

1678 Cal Advocates Opening Brief, p. 152.

1679 Cal Advocates Opening Brief, p. 152; CALPA-07, p. 7, Table 7-5.

1680 CALPA-07, p. 9, lines 7-9.

1681 PG&E-17, p. 4.3-4, Table 4.3-2, line 3; p. 4.3-72, Table 4.3-7, line 3; and p. 4.3-73, Table 4.3-8, line 3.

1682 Cal Advocates Opening Brief, p. 154.

1683 CALPA-07, p. 17, line 10 to p. 18, line 3.

Cal Advocates' forecasting methodology is not reasonable because the work conducted in 2021 is not necessarily representative of the work forecast by PG&E for the GRC period. Therefore, the recorded costs for 2021 (which Cal Advocates uses to calculate an average unit cost) are not a reasonable proxy for the subsequent years. PG&E's forecast should not be reduced based upon recorded costs/average unit costs that are not representative of the work planned.

4.4.2.2 PG&E's Capital Forecast For Line Sensors (MAT 49I) Is Reasonable

PG&E's capital forecasts for PG&E's Line Sensor program (MAT 49I) are $12.369 million in 2021, $23.036 million in 2022, $22.653 million in 2023, $21.711 million in 2024, $22.696 million in 2025, and $24.405 million in 2026.

In its Opening Brief, Cal Advocates argues that the Commission should adopt PG&E's 2021 recorded cost data and approve the same amount for 2022 and 2023.[1684]

Again, it is unreasonable to use PG&E's 2021 recorded costs as a basis for it 2022 and 2023 forecasts because the work completed in 2021 is very different than the work forecast for 2022 and 2023. There are two basic components and costs related to the line sensor program: (1) the labor and materials to install an individual device; and (2) the information technology operational infrastructure supporting the increased volume of the line sensor equipment.[1685] PG&E explained in its testimony that deployment costs should also factor in IT costs for data integration and grid sensing analytics to support grid operations.[1686] In 2021, PG&E incurred costs for labor and materials to install devices but did not perform any IT integration work.[1687] In 2022 and 2023, however, PG&E will install devices and will conduct the necessary IT work

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1684 Cal Advocates Opening Brief, p. 155.

1685 PG&E-04, p. 4.3-58, lines 3-12.

1686 PG&E-04, p. 4.3-57, lines 23-25.

1687 PG&E-04, p. 4.3-58, lines 18-19.

including building the IT infrastructure, conducting integration work, and building out operations centers and other facilities.[1688] PG&E explained in its workpapers that the 2022 plan funds additional IT spend to integrate all of the sensor technologies and that each system has its own development and integration schedule and results in varying annual totals.[1689] Because PG&E will conduct IT work in 2022 and 2023 that it did not do in 2021, the recorded costs and associated unit costs for 2021 are not a reasonable proxy for spending in this GRC period and PG&E's forecast should not be reduced.

4.4.2.3 Distribution Grid Sensor (MWC 49)

Cal Advocates notes that PG&E planned to replace its entire recloser assembly in 2021 because the product it received from the original vendor was unreliable.[1690] Because the recloser was unreliable, Cal Advocates recommends that PG&E be required to provide customer refunds when and if it receives reimbursement from the vendor.[1691] PG&E agrees and will credit the Wildfire Management Balancing Account with any amounts received from the manufacturer.[1692]

4.4.3 Enhanced Powerline Safety Settings

PG&E discusses Cal Advocates' and TURN's recommendations for EPSS below.

4.4.3.1 Cal Advocates' Recommendation Should Not Be Adopted

Cal Advocates did not discuss or make a recommendation for EPSS in its prepared testimony. In the JCE, Cal Advocates affirmatively stated that it did not oppose PG&E's

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1688 PG&E-17, p. 4.3-59, lines 7-9.

1689 PG&E-04, WP 4-114.

1690 CALPA-07, p. 20, lines 18-19.

1691 CALPA-07, p. 21, lines 17-19.

1692 PG&E-17, p. 4.3-55, lines 12-13.

forecast for EPSS and recommended no reductions.[1693] Nonetheless, in its Opening Brief, Cal Advocates makes the following statement:

> PG&E claims the [sic] EPSS became necessary in the update due to the substantial increase in the circuit mile underground. As such, the cost is part of the incremental cost of underground. The Commission should adopt Cal Advocates' risk informed recommendation summarized in Section 4.2 above regarding Electric Distribution Risk Management prior to approving any EPSS requests associated with PG&E's system hardening proposals.[1694]

Cal Advocates' recommendation should be rejected because it is based on a mistaken premise. Cal Advocates cites no support for its claim that PG&E stated that EPSS became necessary to due to the increase in undergrounding miles or its conclusion that EPSS is part of the incremental cost of undergrounding. There is a good reason for this – no such support exists. PG&E included an EPSS forecast in its February 25, 2022 GRC update not because it was part of the undergrounding program, but because it was a new mitigation that PG&E developed – after its initial GRC forecast was prepared –to reduce ignition risk by changing device settings in HFTDs, High Fire Risk Areas (HFRA) and select circuits in adjacent buffer areas.[1695] The scope of the EPSS program is different from PG&E's undergrounding program. For example, PG&E plans to make devices EPSS-capable on most circuits in HFTD, HFRA, and buffer areas (and enable EPSS settings based on approved thresholds informed by weather modeling), whereas undergrounding is planned for a much smaller area in this GRC period.[1696] Moreover, EPSS is a stand-alone wildfire risk mitigation that PG&E would employ even if it did not have an undergrounding program. The relationship between these programs is that EPSS will provide some temporary risk mitigation on overhead circuits that PG&E plans to convert to underground

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1693 PG&E-64, Joint Comparison Exhibit, p. 2-230.

1694 Cal Advocates Opening Brief, pp. 157-158.

1695 PG&E-04, p. 4.6-1, line 5 to p. 4.6-8, line 2.

1696 PG&E-04, p. 4.6-7, lines 7-9 ("In 2022, PG&E will expand the program to enable EPSS mode in most HFTD and HFRA areas and select circuits in buffer zones immediately adjacent to those areas."); PG&E Reply Brief, Section 4.3.1.1 (PG&E's adjusted forecast for undergrounding).

until the undergrounding work actually takes place. As such, the "risk-informed recommendation" discussed in Section 4.2 of Cal Advocates' Opening Brief, which is tied to the undergrounding program, is not appropriate for the EPSS program.

4.4.3.2 TURN's Recommended Reduction To PG&E's EPSS Post-Outage Patrol Forecast Should Not Be Adopted

As discussed in PG&E's Opening Testimony, EPSS is a new mitigation that has become a critical element of PG&E's wildfire mitigation program. EPSS reduces the potential for wildfire ignitions by increasing the sensitivity and speed of system protective devices on circuits in HFTD/HFRA areas so that power is automatically shut off within one-tenth of a second if a fault is detected on the distribution line.[1697] PG&E implemented EPSS for part of the fire season in 2021 on approximately 11,500 HFTD circuit miles.[1698] After EPSS was implemented, CPUC-reportable ignitions from electrical equipment were approximately 80 percent lower in 2021 (compared to a three-year average) on EPSS-enabled circuits in HFTD/HFRA areas.[1699] Beginning in 2022, PG&E expanded the EPSS program to the entire HFTD/HFRA and select buffer areas and the program will operate for the entire fire season, seven months at a minimum and possibly year-round.

PG&E's 2023 expense forecast for EPSS is $151.1 million.[1700] The majority of PG&E's EPSS forecast is for post-outage patrols on EPSS-enabled circuits. TURN recommends a $64.1 million reduction to PG&E's forecast for EPSS post-outage patrols based on its assertion that PG&E should have based its forecast on per circuit mile historical costs instead of per circuit historical costs.[1701]

1697 PG&E Opening Brief, p. 442.

1698 PG&E Opening Brief, p. 443.

1699 PG&E-04, p. 4.6-6, line 33 to p. 4.6-7, line 2.

1700 PG&E Opening Brief, p. 443, Table 4-7.

1701 PG&E Opening Brief, p. 443.

PG&E addressed this issue at length in its Opening Brief, explaining that the per circuit forecast was a reasonable proxy, given the novelty of the EPSS program and paucity of cost data from which to forecast.[1702] TURN argues that its forecast based on PG&E's 2021 recorded per circuit mile cost is a more appropriate measure,[1703] but PG&E explains in its rebuttal testimony and Opening Brief two reasons why TURN's forecast is too low: (1) TURN's unit cost is based on PG&E's 2021 EPSS program, which only operated for part of the fire season,[1704] and (2) TURN's reliance on 2021 costs does not take into consideration that the expansion of the program will increase costs because more EPSS-enabled miles will result in more outages (each of which represents a potential ignition avoided) and because multiple, overlapping outages increase PG&E's reliance on contractor, overtime pay, and aviation resources to quickly and efficiently perform post-outage inspections.[1705] TURN states that "PG&E does not provide a price tag for any of these potential costs"[1706] – but PG&E's forecast is a reasonable estimate whereas TURN's alternate forecast clearly fails to account for the additional costs that PG&E expects to incur as a result of expanding the scope of EPSS. PG&E notes that its EPSS forecast is part of the WMBA, so in the event that PG&E spends less than authorized, those funds will be returned to customers.

TURN also suggests that its proposed reductions will "incentivize[] strategic reliance on EPSS that would minimize the reliability impacts on PG&E customers consistent with the Office of Energy Infrastructure Safety feedback on the program."[1707] The Office of Energy Infrastructure Safety (OEIS or Energy Safety) did require PG&E take steps to better understand

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1702 PG&E Opening Brief, p. 443-444.

1703 TURN Amended Opening Brief, pp. 429-430.

1704 PG&E Opening Brief, p. 444-445; PG&E-17, p. 4.6-8, line 1 to p. 4.6-9, line 3.

1705 PG&E Opening Brief, p. 444; PG&E-17, p. 4.6-7, lines 5-30.

1706 TURN Amended Opening Brief, p. 431.

1707 TURN Amended Opening Brief, p. 428.

and, if possible, mitigate the reliability impact of EPSS as part of PG&E's 2022 WMP process,[1708] but its guidance does not warrant reduction in the scope of the EPSS program given the evidence of the program's effectiveness in reducing wildfire ignitions.

4.5 Emergency Preparedness And Response (EP&R)

The Commission should approve PG&E's TY 2023 expense forecast for EP&R presented as: (1) $26.451 million in rebuttal testimony;[1709] and (2) $29.557 million in the JCE with the September escalation adjustment.[1710]

The Commission should also approve PG&E's capital expenditures forecasts for EP&R presented as: (1) $2.046 million for 2021, $1.966 million for 2022, and $5.502 million for 2023,[1711] $5.409 million in 2024, $5.457 million in 2025, and $5.626 million in 2026 in rebuttal testimony;[1712] and (2) $2.109 million in 2021, $2.143 million for 2022, and $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 expenditures forecast including the September escalation adjustment.[1713]

PG&E understood that no party disputed PG&E's expense and capital forecasts, as indicated in Appendix A. In its Opening Brief, Cal Advocates states that it recommends a reduction of $1.1 million to PG&E's combined capital forecast from 2021-2023, based on PG&E's recorded costs for 2021, which are $1.1 million less than forecast. PG&E does not dispute the reduction based on actual 2021 recorded capital expenditures as long as the true-up

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1708 PG&E's 2022 WMP, OEIS Docket #2022-WMP, Draft Decision on 2022 WMP Update – PG&E (Oct. 6, 2022), pp. 125-130 (Section 4.6.6.3, discussion of Critical Issue RN-PG&E-22-12).

1709 PG&E-17, p. 2-4, Table 2-1, line 7.

1710 PG&E-64, p. 3-2, Table 3A-1, line 58.

1711 PG&E-17, p. 2-5, Table 2-2, line 5 (2021); p. 2-6, Table 2-3, line 5 (2022); p. 2-7, Table 2-4, line 5 (2023).

1712 PG&E-67, WP-2, line "[Exhibit 4, Chapter] 5," MWC 21.

1713 PG&E-67, WP-2, line "[Exhibit 4, Chapter] 5," MWC 21.

for recorded costs is for all programs, and is not selectively requested only where the 2021 recorded costs are lower than PG&E's 2021 forecast.[1714]

4.6 Electric Emergency Recovery (EER)

4.6.1 Overview

The Commission should approve PG&E's TY 2023 expense forecast for Electric Emergency Recovery presented as: (1) $136.466 million in rebuttal testimony;[1715] and (2) $149.216 million in the JCE with the September escalation adjustment.[1716]

The Commission should also approve PG&E capital expenditures forecast for EER presented as: (1) $269.595 million for 2021, $311.368 million for 2022, $319.184 million for 2023, $328.424 million in 2024, $337.910 million in 2025, and $347.674 million in 2026 in rebuttal testimony;[1717] and (2) $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 in the JCE with the September escalation adjustment.[1718]

The funding requested for EER is necessary for PG&E 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) recover straight-time (ST) labor when responding to CEMA-eligible events.[1719] PG&E's expense and capital forecast for EER consists of three components: (1) Routine Emergency; (2) Major Emergency; and (3) Catastrophic Event Straight-Time Labor.

1714 PG&E Opening Brief, pp. 20-21.

1715 PG&E-17, p. 2-4, Table 2-1, line 8.

1716 PG&E-64, p. 3-2, Table 3A-1, lines 59-60.

1717 PG&E-17, p. 6-16, Table 6-5, line 4.

1718 PG&E-67, WP-2, lines "[Exhibit 4, Chapter] 6," MWCs 17 and 95.

1719 PG&E-04, p. 6-1, lines 10-16.

Cal Advocates opposes PG&E's capital forecasts for Routine Emergency (MWC 17) and Major Emergency (MWC 95), based on a forecast methodology that departs from prior GRC precedent. Cal Advocates and TURN both oppose PG&E's expense and capital forecast for the proposed Catastrophic Event Straight Time Labor Balancing Account (CESTLBA).[1720] Finally, TURN makes a non-financial recommendation related to PG&E's Major Event Balancing Account (MEBA) forecast.[1721]

PG&E responds to Cal Advocates' and TURN's contentions below.

4.6.2 PG&E's Routine Emergency (MWC 17) Capital Forecast Is Reasonable

Routine Emergency (MWC 17) costs generally cover PG&E's power restoration efforts for emergency outages caused by equipment failure.[1722] PG&E's capital forecast for Routine Emergency presented in rebuttal testimony is $193.244 million in 2021, $233.354 million in 2022, $239.188 million in 2023, $246.137 million in 2024, $253.271 million in 2025, and $260.615 million in 2026. These forecasts are subject to escalation as proposed in PG&E's September, 2022 update.

In its Opening Brief, Cal Advocates recommends Routine Emergency capital forecasts of $161.267 million in 2021, $197.260 million in 2022, and $202.586 million in 2023, which are all approximately fifteen percent lower than PG&E's capital forecasts for these years.[1723] Cal Advocates' recommended reductions are based on two alternative forecasting proposals. First, Cal Advocates proposes using a 5-year average of historical costs, rather than the 3-year average adopted in past GRC decisions and used again by PG&E in this GRC.[1724] Second, Cal Advocates recommends reducing the forecast based on PG&E's completion of risk-

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1720 Cal Advocates Opening Brief, pp. 164, 442-443; TURN Amended Opening Brief, p. 432.

1721 TURN Amended Opening Brief, pp. 440-442.

1722 PG&E-04, p. 6-7, lines 7-9.

1723 Cal Advocates Opening Brief, p. 160, Table 6-2.

1724 Cal Advocates Opening Brief , p. 160; CALPA-06, p. 12, lines 7-13.

mitigation work, which according to Cal Advocates should reduce the occurrence of catastrophic events and their associated costs.[1725] The Commission should reject these alternative forecasting proposals. As explained in further detail below, Cal Advocates' averaging proposal is inconsistent with PG&E's historical GRC forecasting methodology for these types of costs, as approved by the Commission in prior GRCs. In addition, PG&E's forecast already reflects risk reductions obtained through PG&E's various risk-mitigation work completed to date.

4.6.2.1 PG&E's Use Of A Three-Year Average To Forecast Routine Emergency (MWC 17) Capital Costs Is Appropriate

In regard to forecasting methodologies, PG&E routinely uses and the Commission has approved using 3-year historical averages to forecast costs in Electric Distribution.[1726] This methodology allows PG&E to account for some year-to-year variability, while also capturing the most up-to-date labor and materials costs.[1727] PG&E uses a 5-year average less frequently in certain limited circumstances, because it does not reflect current labor and materials costs as closely as a 3-year average.[1728] In this GRC (as in prior GRCs), PG&E used a 3-year average to forecast Routine Emergency (MWC 17) to account for more-recent labor and materials costs, and used a 5-year average to forecast Major Emergency (MWC 95) costs given that the number and scope of major emergencies such as storms, earthquakes and fires can vary significantly, making a 5-year average appropriate.[1729] For multiple GRC proceedings, PG&E has used, and the Commission has approved, PG&E's Routine Emergency forecast based on a 3-year average

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1725 Cal Advocates Opening Brief, pp. 160-161; CALPA-06, p. 12, line 14 to p. 15, line 15.

1726 D.20-12-005, p. 95.

1727 PG&E-17, p. 6-7, lines 13-16.

1728 PG&E-17, p. 6-7, lines 16-17.

1729 PG&E-17, p. 6-7, lines 16-20.

and Major Emergency forecast based on a 5-year average.[1730] There is no reason to depart from that precedent in this GRC. Cal Advocates' proposal to use a 5-year average for the Routine Emergency capital forecast is inconsistent with Commission precedent approving PG&E's routine emergency forecasts in prior GRCs, and has the appearance of selective manipulation of an averaging methodology solely for the purpose of deriving a lower forecast. This is improper forecasting if that is the case.

In its Opening Brief, Cal Advocates justifies its proposal to use a 5-year average to derive a lower Routine Emergency (MWC 17) forecast by arguing that 2020 was an abnormally high year compared to any year from 2013-2019.[1731] Cal Advocates cites no evidence in support and its assertion that a 3-year average that uses 2020 data is not a "true average"[1732] is unfounded. There is no doubt that a 3-year average is a "true average" for the 3-year period that is the basis of PG&E's forecast. Further, PG&E's workpapers show that 2020 was not abnormally high when considering that recorded costs for Routine Emergency (MWC 17) have increased annually for the past five years, with a 13.3% percentage increase from 2018 to 2019 roughly matching a 16.4% increase from 2019 to 2020.[1733] This annually-increasing cost trend shows that using a 3-year average is more appropriate, as it better reflects current market conditions than a 5-year average, while at the same time moderating PG&E's forecast given that a forecast based on the last-year recorded with escalation could have been justified. Routine Emergency costs also lack the up-and-down annual variability that make a 5-year average appropriate.

1730 PG&E-17, p. 6-7, lines 21-24; D.20-12-005 (GRC 2020), pp. 94-95; D.17-05-013 (2017 GRC), p. 246, OP 1 (adopting the Settlement Agreement between parties, including the Routine Emergency forecast based on a 3-year average). *See*, A.15-09-001, Exhibit (PG&E-23) p. 4-6, lines 13-15.

1731 Cal Advocates Opening Brief, p. 161.

1732 Cal Advocates Opening Brief, p. 161.

1733 PG&E-04, WP 6-27, Table 6-19, line 6.

4.6.2.2 Recorded Costs Already Reflect The Reduced Impact Of Completed Risk Mitigation Activities And No Additional Downward Adjustment Is Warranted

In addition, there is no valid reason to reduce PG&E's Routine Emergency capital forecasts based on PG&E's completion of risk-mitigation work in prior years. Cal Advocates suggests that risk-mitigation work in recent years should reduce the frequency and impact of ignitions and therefore Routine Emergency costs going forward.[1734] As a threshold matter, Routine Emergency (MWC 17) includes response activities in both HFTDs and non-HFTDs. Much of the risk mitigation work, however, is being performed in the HFTDs; therefore, the work only reduces the frequency and impact of Routine Emergency costs within the HFTDs, with less reduction in non-HFTDs. In any event, to the extent Cal Advocates is correct, PG&E's forecast already reflects the reduced risk, because the recorded costs used in the averaging to develop the forecast reflect how PG&E's post risk-mitigation may have reduced Routine Emergency response activities and associated costs, if at all.[1735] That is, if there are any reduced Routine Emergency response costs due to PG&E's risk-mitigation work, those reduced costs are reflected in the historical costs used to calculate the 3-year average of those costs. There is no basis for applying an additional speculative downward adjustment, particularly given that doing so would depart from historical averages. This issue is also discussed in Sections 4.2.3.4 and 4.6.1 of PG&E's Opening Brief.

In sum, the Commission should reject Cal Advocates' proposal to use a 5-year average with an additional downward adjustment and should adopt PG&E's Routine Emergency (MWC 17) capital forecast based on a 3-year average. The funding requested by PG&E is necessary for PG&E to effectively respond to routine emergencies caused by equipment failures, in compliance with GO 166 (Standards for Operation, Reliability, and Safety) during Emergencies and Disasters.

1734 Cal Advocates Opening Brief, pp. 161-162.

1735 PG&E-17, p. 3-32, lines 4-12.

4.6.3 PG&E's Major Emergency (MWC 95 Excluding CESTLBA) Capital Forecast Is Reasonable

Major Emergency (MWC 95) costs generally cover PG&E's power restoration efforts for emergency outages caused by weather events, wildfires, and other natural disasters.[1736] PG&E's capital forecast for Major Emergency (MWC 95 Excluding CESTLBA) presented in rebuttal testimony is $60.810 million in 2021, $62.069 million in 2022, $63.621 million in 2023, $65.470 million in 2024, $67.367 million in 2025, and $69.321 million in 2026. These forecasts are subject to escalation as proposed in PG&E's September, 2022 update.

In its Opening Brief, Cal Advocates recommends Major Emergency (MWC 95) capital forecasts of $52.699 million in 2021, $53.790 million in 2022, and $55.135 million in 2023, which again are all about fifteen percent lower than PG&E's capital forecasts for these years.[1737] Cal Advocates accepts the 5-year averaging methodology used by PG&E, but similar to its recommendation for the Routine Emergency (MWC 17) forecasts, Cal Advocates recommends reducing PG&E's Major Emergency (MWC 95) capital forecasts on the ground that completed risk mitigations should reduce the frequency or impact of emergencies.[1738] As discussed above in Section 4.6.2.2, there is no valid reason for reducing the forecasts, which are based on historical costs that already reflect Major Emergency cost reductions, if any, realized through the reduced risk obtained through PG&E's mitigation work. The Commission should reject Cal Advocates' proposed reduction and adopt PG&E's Major Emergency capital forecasts.

In Section 4.6.5, PG&E addresses an additional non-financial recommendation from TURN regarding PG&E's Major Emergency Forecast.

1736 PG&E-04, p. 6-7, lines 9-10.

1737 Cal Advocates Opening Brief, p. 160, including Table 6-2.

1738 Cal Advocates Opening Brief, pp. 161-162; CALPA-06, p. 12, lines 14-16.

4.6.4 PG&E's Proposal to Establish A CEMA Straight Time Labor Balancing Account (MWCs IF and 95) Is Reasonable

PG&E proposes to recover ST labor costs associated with its repair and restoration activities for CEMA-eligible events through a new two-way balancing account referred to as the CESTLBA. If PG&E's proposal is approved, PG&E would record CEMA ST labor for qualifying events in a two-way CESTLBA so that any underspent amounts may be returned to customers and overspent amounts are allowed for recovery. PG&E would stop recording CEMA ST labor costs to the CEMA, and PG&E's CEMA applications would only seek recovery of other non-labor-related expense, capital expenditures, certain limited overheads, and overtime and double time labor costs[1739] associated with PG&E's repair and restoration activities following a CEMA-eligible event. PG&E's baseline TY 2023 expense forecast for the CESTBLA is $20.079 million, and its capital forecasts are $15.542 million in 2021, $15.945 million in 2022, $16.375 million in 2023, $16.817 million in 2024, $17.271 million in 2025, and $17.738 million in 2026.

Cal Advocates and TURN oppose PG&E's proposal, recommending that the Commission deny the CESTBLA and authorize zero funding for CEMA ST labor.[1740]

4.6.4.1 The Commission Should Approve The CESTBLA To Resolve Uncertainty Regarding The Recovery Of Straight-Time Labor Costs

As explained in testimony, CEMA cost recovery disputes have been going on for several years in PG&E's CEMA cost-review proceedings. Historically, dating back at least a decade, Cal Advocates and TURN have argued against the recovery of CEMA ST labor in PG&E's CEMA application proceedings on the ground that the ST labor costs associated with PG&E's CEMA-related restoration and repair activities are not incremental to base rates approved in the GRC and GT&S proceedings. In particular, Cal Advocates and TURN have argued that when

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1739 PG&E-04, p. 6-24, line 1 to p. 6-27, line 14, Section F.2.

1740 Cal Advocates Opening Brief, pp. 162-164; CALPA-04, p. 16, line 18 to p. 19, line 14; TURN-12, p. 2, lines 2-4; TURN-13, p. 29, line 15.

PG&E uses existing staff to respond to a CEMA event, the ST labor associated with the response activities has already been funded through GRC and GT&S approved rates.[1741] PG&E has disputed this argument by explaining that PG&E's GRC and GT&S forecasts are activity based and seek funding for work activities specifically identified in the GRC, not staffing, and that PG&E specifically removed CEMA recorded costs (including CEMA ST labor) from the recorded costs used to develop PG&E's GRC forecasts. For both these reasons, it has been manifestly incorrect for Cal Advocates and TURN to contend in the CEMA cost-review proceedings that CEMA ST labor costs for these employees have already been funded in a GRC.

Cal Advocates' and TURN's opposition to the proposed CESTLBA and CEMA ST labor forecast is perplexing given the position they have consistently taken in the past several CEMA proceedings that recovery of CEMA ST labor costs should be disallowed because labor costs for existing staff who respond to CEMA events are supposedly recovered in the GRC. This argument suggests that the GRC is the appropriate proceeding for PG&E to propose a forecast that is sufficient for completing all activities, including those associated with responding to CEMA events. But now, when PG&E has forecast those costs in the GRC and requested a two-way balancing account to record actual costs, Cal Advocates and TURN argue incongruently that CEMA ST labor should not be forecasted or recovered in the GRC.[1742]

Cal Advocates and TURN cannot have it both ways (or put another way, both of their arguments cannot be true). Otherwise, Cal Advocates and TURN will have constructed a regulatory Catch-22 where: (1) PG&E cannot recover CEMA ST labor costs in a CEMA proceeding because according to them, all ST labor costs are already forecasted and recovered in the GRC; but (2) PG&E is prohibited from fully forecasting ST labor in the GRC to include CEMA ST labor because CEMA costs can only be recovered upon a showing of incrementality.

1741 TURN-12, p. 6, lines 16-18. See also, A.20-09-019, Exhibit (PA-08), p. 4, line 10 to p. 11, line 23; A.21-09-008, HE-PA-04: Exhibit (Cal Advocates-04), Section V.

1742 CALPA-04, p. 16, line 18 to p. 19, line 14; TURN-12, p. 6, lines 16-18.

The Commission should reject one of Cal Advocates' and TURN's arguments in order to resolve this Catch-22. The Commission can do this by either: (1) adopting PG&E's forecast and authorizing the CESTBLA, or (2) issuing a finding rejecting Cal Advocates' and TURN's assertion that the GRC fully funds existing staff who respond to a CEMA event.

4.6.4.2 Approving The Proposed CESTBLA Ensures PG&E Is Sufficiently Funded For All Activities Intervenors Contend Are Funded In The GRC

4.6.4.2.1 TURN Misunderstands Essential Facts Regarding PG&E CEMA Response Activities And What Funding Received In The GRC For ST Labor Covers

In its Opening Brief, TURN suggests that this dispute boils down to a question of incrementality.[1743] TURN's framing of the issue in this way misses the larger point of PG&E's proposal. In short, the dispute boils down to whether PG&E is sufficiently funded for ST labor for all activities – base work and catastrophic event (CEMA) response – through the GRC, as contended by Cal Advocates and TURN. This is not just semantics. The issue of incrementality fundamentally depends upon what level of funding has been authorized in the GRC. As explained in further detail below, PG&E historically has not requested nor received GRC-funding for ST labor necessary to respond to CEMA events. The proposed CESTBLA seeks 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.

TURN identifies what it believes are the critical facts necessary to understand the issue.[1744] Most of these assertions, which are based upon PG&E's data request responses, are

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1743 TURN Amended Opening Brief, p. 432.

1744 TURN Amended Opening Brief, pp. 433-434.

generally accurate.[1745] TURN errs, however, when it asserts that PG&E expects to reprioritize Routine Emergency work when CEMA events occur and that CEMA response work is performed by GRC-funded PG&E crews who conduct Routine Emergency response activities, incorrectly suggesting that Routine Emergency activities are among the activities deferred when PG&E responds to a CEMA event.[1746] TURN provides no citation to the evidentiary record in support of this assertion and it is unclear what TURN's basis is for this incorrect understanding. Routine Emergency response activities relate to PG&E's power restoration efforts for emergency outages caused by equipment failure.[1747] PG&E typically would not postpone this work when responding to a CEMA event. Both outage-restoration workstreams must be completed without delay.

This is a significant factual error because TURN relies on that error to reach its faulty conclusion that PG&E is already being funded for CEMA response activities based on the expense and capital funding approved in a GRC for Routine Emergency (MWC 17 and MWC BH). That is not so. PG&E does not receive GRC funding for responding to CEMA through its Routine Emergency forecasts or any other GRC forecasts.

The following example illustrates what PG&E's GRC funding requests covered in prior GRCs. For this example, assume there are a set of PG&E Electric Operations employees who work on a variety of activities, including GRC-funded base activities and CEMA response

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1745 According to TURN these facts include: (1) PG&E does not staff full time employees (FTEs) for CEMA events or adjust staffing for various employees who charge to CEMA; (2) PG&E deprioritizes work in other areas when responding to a CEMA event; (3) PG&E crews who responded to the CEMA event return to their routine duties, including postponed activities, once the CEMA work has concluded; (4) The completion of the postponed activities requires incremental overtime labor and contractor resources; (5) The incremental costs associated with completing the postponed activities are not charged to CMEA specific orders, but rather are incurred to replace the ST labor and overtime originally intended for executing the base work. These five facts are generally accurate and support PG&E's forecast requests for non-CEMA work based upon recorded costs. (*Id.*)

1746 TURN Amended Opening Brief, pp. 433-434.

1747 PG&E-04, p. 6-7, lines 7-9.

activities. When the employees work on GRC-funded base activities, they record time and costs, including ST labor, to the corresponding MWC/MAT code for those base activities, which could include any of the activities forecast in Exhibit PG&E-04 – Routine Emergency, Major Emergency, inspection and maintenance activities, poles, network asset management, etc.[1748] When the employees work on CEMA response activities, they record their time and costs, including ST labor, to CEMA.[1749] When submitting prior GRC applications, PG&E forecasted base-work activities by MWC/MAT codes, based on the recorded costs for those activities. But PG&E fully removed CEMA ST labor costs from its prior GRC forecasts starting with the 2020 GRC, taking 100 percent of the CEMA costs from the Major Emergency (MWCs IF and 95) forecast.[1750] What this means is that PG&E's prior GRC forecast covered ST labor for all GRC base activities, but did not include ST labor for CEMA. That is, PG&E's prior GRC forecasts did not provide funding for CEMA activities. Further, PG&E's forecast for Routine Emergency is based on historical costs recorded to the Routine Emergency (MWC 17 and MWC BH) and does not include *any* costs related to responding to CEMA events. Had CEMA activities been included in prior GRCs, the forecasts would have been higher.

TURN argues that removal of these costs does not demonstrate incrementality of CEMA ST labor costs because the CEMA response activity could be funded by existing resources without any need to hire additional staff.[1751] In making this claim, TURN speculates PG&E staff may have "slack time" that allows it to complete CEMA recovery work while performing

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1748 See, e.g., PG&E-04, Chapter 6, Section D (routine emergency and major emergency forecasts estimating method) and Tables 6-12 and 6-13 (recorded costs by MWC/MAT); Chapter 11, Section D (overhead and underground electric distribution maintenance forecasts estimating method) and Tables 11-17 and 11-18 (recorded costs by MWC/MAT); Chapter 12, Section D (poles forecast estimating method) and Tables 12-9 and 12-10 (recorded costs);

1749 See, e.g., PG&E-04, lines 26-29.

1750 PG&E-04, p. 6-22, line 2-3; PG&E-17, p. 6-11, lines 3-8; PG&E-17, Chapter 6, Attachment A, pp. 6-AtchA-3, 6-AtchA-4, and 6-AtchA-5 (workpapers showing CEMA costs removed).

1751 TURN Amended Opening Brief, p. 435.

all of the other activities forecast in a GRC.[1752] This characterization is untrue to the extent it suggests PG&E Electric Distribution workers who respond to CEMA events may have idle time in connection with their other work. PG&E utilizes all of its Electric Distribution workers (troublemen, linemen, electricians) to complete all necessary work – GRC base activities and CEMA work – as safely and efficiently as possible. There is no "slack time" in their workdays as suggested by TURN. The more appropriate explanation is that through a combination of internal work efficiencies and/or contractors, PG&E is able to complete its GRC base activities and unplanned work that arise due to a CEMA event. PG&E respectfully submits that in this situation, PG&E should have the opportunity to receive full funding for this work, including when it may be able to find work efficiencies that allow it to complete work without hiring additional staff or contractors. The utility-funding model PG&E urges the Commission to follow is what any contractor would expect from PG&E. That is, if PG&E engaged its contractor to complete certain activities within the scope of the contract, and the contractor completed that work plus additional activities arising from a CEMA event, the contractor would reasonably expect funding for that additional CEMA work, even if the contractor did not hire additional staff to complete the work. TURN offers no valid reason why the Commission should depart from that indisputable funding model when PG&E staff completes the additional work.

TURN further suggests that the completion of additional CEMA work may not be incremental because PG&E deferred work, with no harm to PG&E because the utility can request funding for the deferred work in the next GRC.[1753] First, there is no evidence of CEMA-caused deferred work presented by TURN in this proceeding. The only evidence of deferred work presented in this proceeding generally identified certain activities deferred due to PG&E's wildfire mitigation efforts and other changed priorities.[1754] Second, TURN's claim

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[1752] TURN Amended Opening Brief, pp. 435-436.

[1753] TURN Amended Opening Brief, p. 436.

[1754] PG&E-04, Chapters 4-22 (deferred work analysis sections).

that there would be no harm to PG&E is belied by the fact that intervenors such as TURN frequently oppose cost recovery of deferred work on the ground that it had previously been authorized in prior GRCs.

4.6.4.2.2 The Commission Should Resolve The Uncertainty Regarding The Recovery Of CEMA ST Labor Costs

In addition, PG&E's demonstration that CEMA costs have been removed from prior GRC forecasts is not merely a "theoretical accounting" argument with no negative financial impact shown, as TURN mischaracterizes.[1755] Rather, there would be a substantial negative financial impact to PG&E to the extent the Commission agreed with Cal Advocates and TURN that ST labor costs for employees who work on CEMA events were already funded through the GRC, a possibility TURN references in its Opening Brief when citing to a proposed decision (PD) issued by the Assigned Administrative Law Judge in A.20-09-019 that would find PG&E's 2020 CEMA ST labor costs not incremental to GRC-authorized amounts.[1756] Notably, TURN neglects to fully discuss an alternate proposed decision (APD) for the same proceeding issued by the Assigned Commissioner holding the opposite conclusion: "Regardless of these analytical differences between the parties, *there is no evidence to suggest that double-counting occurred in this case*. Indeed, the costs claimed here were validated in an independent audit performed by Ernst & Young and *no party has identified duplicative costs*."[1757] In its Opening Brief, TURN misstates that the APD did not reach a decision on this issue.[1758] The APD actually addressed

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1755 TURN Amended Opening Brief, pp. 435-436.

1756 TURN Amended Opening Brief, p. 439. TURN also claims that it provided evidence that PG&E incurred no incremental overtime in connection with costs requested by PG&E in PG&E's 2016 CEMA application (A.16-10-019). (TURN Amended Opening Brief, p. 435.) TURN offers no cite to a Commission decision indicating that its argument was accepted. In any event, a 2016 CEMA cost-recovery application is inapposite to PG&E's request in this 2023 GRC.

1757 A.20-09-019, Alternate Proposed Decision of Commissioner Alice Reynolds (Alternate PD) (Oct. 11, 2022), p. 26 (emphasis added).

1758 TURN Amended Opening Brief, p. 439, fn. 1296.

this issue at length, finding that there was sufficient evidence supporting the incrementality of CEMA ST labor costs.[1759]

The different conclusions reached in the PD and APD reflect the substantial uncertainty that exists and ultimately demonstrates the reasonableness of PG&E's request for the CESTLBA. If adopted, the CESTLBA would eliminate altogether the need for the Commission to address the incrementality of PG&E's CEMA costs in CEMA review proceedings. By adopting the proposed CESTLBA and associated baseline forecast for CEMA ST labor costs, the Commission would approve GRC funding and ratemaking mechanism sufficient for PG&E's recovery of ST labor costs incurred when completing CEMA response activities. As described above, PG&E would stop recording CEMA ST labor costs to the CEMA, and PG&E's CEMA applications would only seek recovery of other non-labor-related expense, capital expenditures, certain limited overheads, and overtime and double time labor costs.[1760]

4.6.4.2.3 PG&E Is Able To Forecast CEMA ST Labor Costs For Recovery In A CESTLBA

Cal Advocates argues that the Commission should deny the CESTLBA because PG&E supposedly cannot accurately forecast CEMA ST labor costs given the inherent variability and unpredictability of CEMA events.[1761] Cal Advocates' argument does not make sense and is inconsistent with the Commission's acceptance of PG&E's averaging of recorded costs as a forecasting methodology for various activities. For the CESTLBA forecast, PG&E reasonably used a 3-year average of CEMA ST labor costs.[1762] The use of an average is no different fundamentally than the forecasting methodology PG&E utilizes to forecast other costs in the GRC, including forecasting for major emergencies (those events that fall short of being a

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1759 A.20-09-019, Alternate PD (Oct. 11, 2022), pp. 22-27, Section 7.1.1.5.

1760 PG&E-04, p. 6-24, line 1 to p. 6-27, line 14, Section F.2.

1761 Cal Advocates Opening Brief, pp. 163-164.

1762 PGE-04, p. 6-26, line 11 to p. 6-27, line 2.

government-declared catastrophic event). There is nothing unusual or inappropriate in using an average to forecast CEMA ST labor costs. Plus, the proposed balancing account protects customers, because PG&E will refund any overcollection to customers if PG&E's actual costs are less than forecast.

4.6.4.2.4 CEMA Costs Do Not Require An After-The-Fact Reasonableness Review

Cal Advocates also argues that CEMA ST labor costs must be reviewed for reasonableness prior to recovery.[1763] PG&E acknowledges that the historical ratemaking procedure has been for utilities to recover CEMA ST labor costs following an after-the-fact reasonableness review. But there is no prohibition under the CEMA statute (Public Utilities Code Section 454.9) or the Commission's rules against recovery of these costs on a forecast basis. As noted by TURN,[1764] the CEMA statute was enacted to protect utilities from the prohibition against retroactive ratemaking.[1765] But this statutory protection does not extend so as to disadvantage utilities if recovery of CEMA costs on a forecast basis is possible. In this GRC, PG&E only seeks recovery of CEMA ST labor costs on forecast basis. The costs recorded in the CESTLBA would then be subject to an advice letter review process. Under PG&E's proposed CESTLBA, costs other than CEMA ST labor, would still be recorded to the CEMA and recovered following an after-the-fact reasonableness review in CEMA review proceeding.

4.6.5 TURN's Recommendation Regarding PG&E's MEBA Forecast Is Not Warranted

In its testimony, TURN made no recommendations regarding PG&E's Major Emergency forecast. But in its Opening Brief, in connection with its objection to the CESTLBA, TURN asserts that PG&E does not necessarily remove all CEMA recorded costs from its Major

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1763 Cal Advocates Opening Brief, p. 164.

1764 TURN Amended Opening Brief, p. 435.

1765 Resolution (Res.) E-3238 (July 24, 1991), p. 2.

Emergency expense and capital forecasts (MWC 95 and MWC IF).[1766] In support, TURN discusses PG&E's supposed failure to remove from its 2017 GRC Major Emergency forecast all disallowances adopted in a 2013 CEMA decision.[1767] There are two problems with TURN's argument. First, PG&E's forecast in the 2017 GRC is not relevant to its forecast in the 2023 GRC. Second, TURN also fails to note that the decision it cites pertained to the Commission's approval of a settlement. There was no finding of unreasonableness in that decision. Therefore, the premise of TURN's argument that PG&E failed to properly remove all costs found to be unreasonable is faulty. Given the absence of a finding of unreasonableness, there was no basis for PG&E to remove the costs from recorded costs used to derive the 2017 GRC forecast.

TURN's recommendation that the Commission instruct PG&E to provide additional transparency regarding its Major Emergency forecasts (MWC 95 and MCW IF) is vague and unnecessary.[1768] If TURN has questions regarding PG&E's future GRC forecasts, it and other intervenors will have an opportunity to conduct discovery and comment on PG&E's forecasts.

4.7 Distribution System Operations

PG&E's forecast for Distribution System Operations is uncontested.[1769]

4.8 Field Metering

Cal Advocates and TURN both make recommendations with respect to PG&E's corrective replacement of Gas AMI modules tracked in MWC 74. Cal Advocates and TURN make similar recommendations with respect to PG&E's proposed proactive replacement of Gas AMI modules. PG&E has addressed all of the Gas AMI module recommendations together in its

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1766 TURN Amended Opening Brief, p. 440.

1767 TURN Amended Opening Brief, pp. 440-442.

1768 TURN Amended Opening Brief, pp. 441-442.

1769 PG&E Opening Brief, pp. 454-455.

Customer Care rebuttal testimony[1770] and Section 6.10 of its Opening Brief.[1771] PG&E provides further support for its forecast in Section 6.10 of this Reply Brief.

TURN also recommends a $0.7 million reduction to PG&E's 2023 forecast of $2.25 million for MWC IU (Collect Revenue) which funds energy theft investigations.[1772] TURN claims that PG&E projects an increase for field employees necessary to support energy theft investigations but does not provide any reasons why energy theft investigations are likely to increase. TURN recommends using PG&E's 2021 forecast plus escalation for the 2023 forecast[1773]

TURN's recommendation for MWC IU should not be adopted because funding based on PG&E's 2021 forecast would be insufficient for the increased number of energy theft investigations that PG&E expects to perform in 2023. As PG&E explained in both rebuttal testimony and its Opening Brief, PG&E's recent spending in MWC IU has been relatively low because of staff attrition during a three-year transition from non-represented technical employees to an IBEW union represented workforce starting in 2017 and because of a COVID-19 related moratorium on Shut-Off for Non-Payment (SONP) field activity. PG&E's energy theft investigations will increase significantly once the SONP moratorium expires in late 2022.[1774] In addition, at hearings, PG&E witness Mr. Craig Kurtz explained that when PG&E restructured the revenue assurance function, they also modernized the work process flow to facilitate an increase in the number of energy theft investigations.[1775] Energy theft investigations provide

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1770 PG&E-19-E, p. 9-13, line 15 to p. 9-26, line 12.

1771 PG&E Opening Brief, pp. 646-657.

1772 PG&E Opening Brief, p. 456, Table 4-12.

1773 TURN-15, p. 2, line 16 to p. 3, line 13.

1774 PG&E-17, p. 8-5, lines 1-27; PG&E Opening Brief, pp. 456-457.

1775 *See* Tr. Vol. 10, 1975:12-20, PG&E/Kurtz.

significant benefit to the public by addressing potential fire risk and unregistered electric usage that can create loading demands that local electric facilities were not designed to handle.[1776]

TURN's Opening Brief claims that PG&E did not provide any reasons or support for "why it believes energy theft investigations would increase drastically to warrant the projected increase in field employees."[1777] This is incorrect – as stated above, PG&E's spending on energy theft investigations has been low for many years due to the transition in the workforce and a COVID-19 related SONP moratorium. Once the moratorium is over, PG&E will significantly increase its number of energy investigations. TURN observes that energy theft investigations started declining in 2017, prior to the COVID pandemic,[1778] but this is irrelevant given PG&E's explanation that energy theft investigations were already at a low level prior to COVID due to the transition for non-union to union labor.

TURN notes that PG&E's recorded spending for MWC IU was lower than forecast in some years and claims without support that "PG&E is now attempting to use the fact that recorded costs were lower than authorized costs to ask for increased funding from ratepayers, even though rates paid by ratepayers during the previous GRC cycle went to shareholder profits."[1779] PG&E's forecast is based on the work that it expects to perform, which is higher than historical amounts for the reasons explained above. TURN's claim that PG&E's recent underspending in MWC IU went to shareholder profits has no foundation; utilities routinely spend less than authorized on some programs while spending more than authorized in others. In any event, that has no bearing on PG&E's business needs going forward. PG&E has amply supported its forecast and the Commission should not adopt TURN's recommendation.

1776 PG&E-17, p. 8-5, line 28 to p. 8-6, line 1.

1777 TURN Amended Opening Brief, p. 442.

1778 TURN Amended Opening Brief, p. 443.

1779 TURN Amended Opening Brief, p. 444.

4.9 Vegetation Management

Cal Advocates is the only party that recommended reductions to PG&E's Vegetation Management forecast.[1780] Cal Advocates' Opening Brief reproduces virtually verbatim the prepared testimony that Cal Advocates submitted.[1781] Cal Advocates' Opening Brief does not refute or even mention PG&E's rebuttal testimony. In fact, Cal Advocates' recommendations in its Opening Brief are still based PG&E's original June 30, 2021 forecast for Vegetation Management rather than the forecast actually at issue in this GRC, PG&E's final February 25, 2022 forecast. With one exception, PG&E's rebuttal testimony and Opening Brief thoroughly address the arguments in Cal Advocates' prepared testimony and Opening Brief.[1782] PG&E will not repeat that material here.

The one issue that PG&E did not discuss in its Opening Brief is Cal Advocates' recommendation that PG&E's Routine VM and Enhanced VM costs for any given year be subject to reasonableness review if they exceed 125 percent of the *five-year average* of Vegetation Management costs rather than the adopted forecast.[1783] This recommendation should not be adopted. Cal Advocates' recommendation is premised on the theory that PG&E's 2020 recorded costs, which form the basis for PG&E's 2023 GRC forecast, were anomalously high. As PG&E explained in its Opening Brief, that is not the case; the increase in costs in 2020 relative to historical amounts was due to factors which will continue going forward, such as an

1780 PG&E Opening Brief, pp. 459-461. California Farm Bureau Federation (CFBF) argues that PG&E should guarantee their proposed "savings" from the claimed reduction in vegetation management with an agreement to not place additional costs on ratepayers beyond what is forecasted. CFBF Opening Brief, p. 16. PG&E's Vegetation Management costs are included in a two-way balancing account. To the extent that PG&E spends more that its forecast amount, its spending is subject to review through the Tier 2 Advice letter process and/or reasonableness review.

1781 Compare CALPA-04, p. 21, line 10 to p. 29, line 24, to Cal Advocates Opening Brief, pp. 172-182.

1782 PG&E-17, p. 9-4, line 1 to p. 9-11, line 7; PG&E Opening Brief, pp. 458-463.

1783 Cal Advocates Opening Brief, p. 177 (Routine VM); p. 181 (Enhanced VM).

estimated 49 percent increase in labor costs related to SB 247.[1784] Because the cost structure for Vegetation Management increased significantly in 2020, it would not be appropriate to trigger a reasonableness review based on PG&E's costs exceeding a five-year average that includes several years with a lower pre-2020 cost structure. PG&E's proposed reasonableness threshold, where review would be triggered if PG&E exceeded its authorized costs in a given year by 125 percent, is a more appropriate metric.

4.10 Overhead And Underground Electric Asset Inspections

4.10.1 Overview

The Commission should approve PG&E's TY 2023 expense forecast for Overhead and Underground Electric Asset Inspections: (1) presented as $89.464 million in rebuttal testimony,[1785] and (2) presented as $106.340 in the JCE with the September escalation adjustment.[1786] PG&E's electric asset inspection program is a key control in allowing PG&E to keep its electric distribution system operating safely and reliably.[1787] Indeed, a comprehensive and proactive inspection program is foundational to maintaining a safe and reliable electric system. Under this program, PG&E regularly inspects its overhead and underground electric facilities 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, in compliance with GO 165 and PG&E's internal standards.[1788]

TURN speculates that PG&E's forecast for patrols and inspections (Section 4.10); overhead distribution maintenance (Section 4.11); and pole replacements (Section 4.12) are all higher than they should be because PG&E allegedly completed inadequate inspections prior to

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1784 PG&E Opening Brief, pp. 461-462.

1785 PG&E-17, p. 10-3, Table 10-1, line 9.

1786 PG&E-64, p. 3-2, Table 3A-1, line 71.

1787 PG&E-04, p. 10-1, lines 24-25; p. 10-3, lines 7-10.

1788 PG&E-04, p. 10-1, lines 25-31; p. 10-4, lines 27-33; p. 10-5, lines 15-21.

implementing the Wildfire Safety Inspection Program (WSIP) in 2019.[1789] According to TURN, the large volume of Electric Corrections (EC) notifications and backlog of assets identified for remediation by PG&E inspectors under WSIP is evidence that PG&E's pre-WSIP inspections were inadequate. TURN argues that these alleged historical inspection failures have increased costs for the subsequent remediation activities and that customers should not be responsible for the higher costs.[1790] TURN's contentions regarding the sufficiency of PG&E's pre-WSIP inspections are unsupported and wrong, and its recommendation to reduce PG&E's forecasts to address various deficiencies identified during WSIP inspections is unwarranted.

PG&E addresses TURN's arguments regarding the sufficiency of pre-WSIP inspections in further detail in Section 4.10.2 below. PG&E addresses TURN's various recommended forecast reductions in Section 4.10.3 (Field Safety Reassessments), Section 4.11 (Overhead distribution maintenance), and Section 4.12 (Poles).

4.10.2 PG&E's Inspection Activities Prior To 2019 Were Sufficient Based Upon The Risks Known At That Time

Contrary to TURN's characterization, the increased number of EC notifications identified under the WSIP was not due to prior inspection failures.

First, as a threshold matter, the pre-WSIP inspections met GO 165 requirements, and TURN offers no valid or credible evidence proving otherwise. TURN cites to the Independent Federal Monitor Report (November 2021) as evidence of prior pre-WSIP shortcomings, but this report pertains to 2021 activities and identifies various areas in which PG&E's gas and electric operations could improve.[1791] PG&E acknowledges the importance of improving its operations, but the report is not evidence that there were substantial pre-WSIP inspection failures. Further, TURN's attempt to use a 2021 report, which focused on PG&E's 2021

[1789] TURN Amended Opening Brief, pp. 445-449, Section 4.10.1.

[1790] TURN Amended Opening Brief, p. 449.

[1791] TURN Amended Opening Brief, p. 448; TURN-09, p. 24, lines 9-11.

inspection activities, to draw such broad generalizations about an alleged inadequacy of inspections completed decades or even just a few years prior to 2021 constitutes faulty reasoning.

TURN further fails to acknowledge that 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. As agreed to by Cal Advocates in a data request regarding pole inspections, for example, it is certainly possible (perhaps even likely) that certain equipment found to be in satisfactory condition during a given year's inspection could be found to be in a degraded condition requiring replacement soon thereafter,[1792] perhaps even within a few days, weeks, or months following the inspection, due to an extreme weather event – extreme heat, extreme cold, extreme wind – or other external factor beyond PG&E's control. And the manifestation of such degradation or failure can often appear suddenly without warning (a fact that is no surprise to anyone who has experienced any sundry of mechanical or electrical mishaps, whether with a flat tire, a bad car battery, a faulty household appliance, etc.). Indeed, as Cal Advocates acknowledges, it is a "virtual certainty" that equipment inspected in any given year will eventually require replacement in some future year.[1793] This does not mean that the inspections prior to the replacement being identified were inadequate as TURN contends, while ignoring how things often work in the real world. It only shows that importance of completing inspections on a regular basis – an activity for which TURN incongruently seeks to reduce funding. TURN's recommended forecast reduction is perplexing and at odds with its assertion that PG&E should complete compliance activities such as inspections in order to reduce the need for other more expensive risk-reduction mitigations.[1794]

1792 PG&E-32, Cal Advocates' response to PG&E Data Request PGE-CalAdvocates_016-Q01, dated 8/9/22.

1793 PG&E-32, Cal Advocates' response to PG&E Data Request PGE-CalAdvocates_016-Q01(c). dated 8/9/22.

1794 TURN Amended Opening Brief, p. 356.

Second, PG&E explained in rebuttal testimony that the increased number of EC notifications was due primarily to PG&E's prudent decision to increase the inspectors' time horizon for assessing abnormal conditions that could cause a catastrophic wildfire.[1795] Discussing only the time-horizon issue, TURN appears to misunderstand that it was a combination of the increased time horizon <u>and</u> wildfire-mitigation focus that led to an increase in notifications.[1796] Pre-WSIP inspections utilized a one-year time horizon and focused on general safety and reliability issues. This made sense, of course, in a pre-wildfire era, and was consistent with the Commission's GO 165 standards at the time. For rural areas from 1997 to 2012, for example, GO 165 required patrols every two years and detailed inspections every five years, with no mention of wildfire risk issues.[1797] Wildfire was subsequently expressly identified as a potential risk in a 2012 amendment to GO 165 inspection requirements, but only for southern California counties.[1798] It was not until several years later that the Commission amended GO 165 inspection requirements to address wildfire risk for equipment in HFTDs throughout California.[1799]

To address wildfire risks as they emerged and were better understood, PG&E established the WSIP and, among other things, changed its inspection criteria to be stricter than GO 165 requirements. In particular, PG&E adopted a five-year time horizon inspection guideline (look ahead period) that focused on mitigating wildfire risk using stricter criteria, meaning inspectors

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1795 PG&E-17, p. 10-7, lines 3-13.

1796 TURN Amended Opening Brief, pp. 446-447. TURN suggests in its opening brief that it is not clear that the increased time horizon is the sole driver of the EC tags, noting that the number of tags for pole replacements is higher than what would be expected from simply extending the time horizon for five years. TURN is correct, in that the driver of the increased EC notifications is the combination of the increased time horizon and wildfire-mitigation focus.

1797 PG&E-61, General Order (GO) 165 (effective March 1997), pp. A1-A4.

1798 PG&E-61, GO 165 (amended January, 2012), p. 4, n. 1 (increasing patrol inspection frequency to address wildfire risks in southern California counties).

1799 PG&E-61, GO 165 (amended December 2017).

were instructed to identify any abnormal wildfire-risk conditions that could emerge and require maintenance within five years.[1800] Thus, wildfire mitigation became a key focus of the program. To meet this objective, the WSIP utilizes a risk-informed approach to proactively identify and address potential sources of wildfire ignition, in contrast to the prior practice of time-driven inspection cycles.[1801] Additionally, PG&E began conducting patrols and inspections in HFTD areas more frequently than the minimum requirements of GO 165, and documenting those patrols and inspections using digital records and photos (using electronic tablets) as opposed to paper records.[1802] These inspection program changes were consistent with, and in many cases exceeded, the Commission's evolving GO 165 standards as discussed above. The prudent inspection guideline changes implemented under WSIP increased the number of abnormal conditions identified, allowing PG&E to address emerging problems sooner in order to effectively mitigate wildfire risk.[1803]

TURN agrees with PG&E's decision to implement a five-year inspection horizon, but is dismissive of PG&E's explanation that the change in the inspection time-horizon and stricter emphasis on wildfire risk increased the EC notification rate.[1804] TURN argues that PG&E's WSIP inspection guidance is largely identical to previous guidance, "the same inspection process with a new name and new time horizon."[1805] Obviously, there are some similarities between the two programs, but TURN does not acknowledge the significance of the prudent changes PG&E implemented to enhance WSIP activities as discussed above – namely the increased time horizon and wildfire risk focus. No different than any other type of inspection of a physical

1800 PG&E-17, p. 10-6, lines 1-20.

1801 PG&E-04, p. 10-5, lines 18-21.

1802 PG&E-04, p. 10-5, lines 24-26; p. 10-9, lines 11-16.

1803 PG&E-17, p. 10-7, lines 3-13.

1804 TURN Amended Opening Brief, pp. 446-448; TURN-09, p. 7, lines 11-12.

1805 TURN Amended Opening Brief, p. 448.

component – whether for cars, airplanes, or electrical components – if an inspector considers the suitability and safety of a component over a longer time horizon and applies stricter criteria when completing an inspection, the inspector will necessarily identify more components as requiring maintenance, replacement, or additional assessment within that longer time horizon. But this does not mean prior inspections were inadequate; it only means that the current inspections are more rigorous – and in the case of PG&E's efforts to mitigate emerging wildfire risks, appropriately so.

TURN also argues that the five-year maximum inspection cycle prescribed by GO 165 for detailed inspections always required a five-year inspection horizon (look-ahead period), and that PG&E was imprudent for using a one-year inspection horizon during certain years pre-WSIP.[1806] Not so. TURN's interpretation of GO 165 is incorrect and would not make sense. For example, if the GO 165-prescribed maximum inspection-cycle requirement were synonymous with the look-ahead period, that would mean that the look ahead period for detailed inspections of poles is indefinite, because there is no required inspection cycle for detailed inspections of poles under GO 165. Rather, GO 165 provides utilities the discretion to determine how to "conduct inspections of its distribution facilities, as necessary, to ensure reliable, high-quality, and safe operation … ."[1807] The GO 165 prescribed inspection cycles only set a minimum standard for the frequency of inspections and do not relate to the inspection criteria a utility should adopt for the inspections. A one-year look ahead period was reasonable to moderate the scope of repairs (and costs) *before* the threat of wildfire dramatically emerged as a critical new risk following the 2017 and 2018 wildfires in northern California. When the severity of these risks in northern California became evident and the mitigating the risk of a catastrophic wildfire became the primary objective under WSIP, PG&E prudently implemented a

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1806 TURN Amended Opening Brief, p. 447.

1807 PG&E-61, GO 165 (amended December 2017), p. 2 (Standards for Inspection).

five-year inspection horizon, specifically assessing whether an abnormal wildfire-risk condition could emerge and require maintenance within five years.

4.10.3 PG&E's Field Safety Reassessments (MAT BF) Are Necessary To Ensure Safety And Must Not Be Defunded

TURN recommends reducing PG&E's forecast to remove $9.7 million for Field Safety Reassessments (FSRs).[1808] While TURN acknowledges that FSRs are arguably prudent, they argue that the FSRs are necessary only because PG&E's pre-WSIP inspections were allegedly inadequate.[1809] An FSR is a field check of an open Electric Correction (EC) notification that will not be addressed before its due date.[1810] FSRs ensure that the risk posed by the condition documented in the EC notification is monitored and can be reprioritized if necessary to resolve the condition on a more expedited timeline.[1811] The Commission should reject TURN's recommendation for three reasons.

First, the underlying premise that PG&E's pre-WSIP inspections were inadequate is incorrect for the reasons discussed above.

Second, TURN acknowledges the speculative nature of its argument that alleged inspection failures tie directly to costs that should be removed from the FSR forecast, when it candidly observes that if remediation work had been identified early it "*may* not have necessitated costly overtime and contract labor." And, TURN offered no evidence regarding the magnitude of the overtime and contract labor it contends should be removed from the FSR forecast. The Commission should not adopt a recommendation that lacks quantifiable analysis.

Third (and most important), an FSR provides the visibility necessary to monitor identified tags and system conditions and serves as a reasonable and comparatively low-cost

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1808 TURN Amended Opening Brief, p. 449; TURN-09, p. 29, lines 3-4.

1809 TURN Amended Opening Brief, pp. 449-450; TURN-09, p. 4, lines 13-20; p. 5, lines 3-5.

1810 PG&E-04, p. 10-26, lines 7-9.

1811 PG&E-04, p. 10-26, lines 15-18.

control to ensure correct prioritization of pending EC notifications in annual work plans. FSRs allow PG&E to monitor equipment identified as degraded to determine whether conditions have worsened such that more-immediate replacement is required, while also ensuring that PG&E does not replace equipment with remaining useful life prematurely. It would be imprudent for PG&E not to monitor asset conditions and prioritize work using the FSR process. In fact, TURN acknowledges this.[1812] Not funding an activity that ensures degraded conditions are appropriately monitored/prioritized and that reduces risk does not make sense and is an unsound approach.

The Commission should reject TURN's recommendation to not fund FSR costs.

4.11 Overhead And Underground Electric Distribution Maintenance

4.11.1 Overview

The Commission should approve PG&E's TY 2023 expense forecast for Overhead and Underground Electric Distribution Maintenance: (1) presented in rebuttal testimony as $94.985 million;[1813] and (2) presented in the JCE with the September escalation adjustment as $111.580 million.[1814]

The Commission should also approve PG&E's capital expenditures forecast: (1) presented in rebuttal as $473.535 million in 2021, $328.029 million in 2022, $344.238 million in 2023, $370.739 million in 2024, $380.872 million in 2025, and $396.023 million in 2026;[1815] and (2) presented in the JCE with the September escalation adjustment as $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.[1816]

1812 TURN-09, p. 1, line 15 (acknowledging that FSRs are arguably prudent).

1813 PG&E-17, p. 11-3, Table 11-1, line 9.

1814 PG&E-64, p. 3-2, Table 3A-1, lines 72-74.

1815 PG&E-17, p. 11-38, Table 11-5, line 14.

1816 PG&E-67, WP-2, lines "[Exhibit 4, Chapter] 11," MWCs 2A and 2B.

As discussed in Section 4.10 above, PG&E's overhead and underground inspections program identifies EC notifications (also known as "tags") for degraded or damaged facilities that pose a safety or reliability risk.[1817] PG&E's electric distribution maintenance (EDM) program involves correcting those conditions, as well as repairing and replacing other assets on a programmatic basis.[1818] PG&E plans and executes the activities in the EDM program to meet the requirements of GO 95 and GO 128, federal regulations and PG&E internal standards.[1819] Almost all EDM activities involve facilities which, if they failed, could potentially disrupt or degrade service or pose an injury risk to the public or PG&E workers.[1820]

In their Opening Briefs, Cal Advocates and TURN reiterate their recommended forecast reductions presented in testimony. In some cases, Cal Advocates' and TURN's recommendations, if adopted, would limit PG&E's ability to perform critical safety- and reliability-related work.

Below PG&E responds to Cal Advocates' and TURN's contentions. Section 4.11.2 responds to Cal Advocates' general argument recommending large forecast reductions based on its speculation that PG&E does not have the capacity to complete the work forecast. Section 4.11.3 through Section 4.11.13 respond to Cal Advocates' and TURN's specific recommended reductions for the twelve MAT-activity forecasts activities they dispute. Section 4.11.14 addresses a non-financial recommendation raised by Cal Advocates.

4.11.2 PG&E's Forecasted Pace of Work For Capital Programs Is Reasonable And Achievable

In general, Cal Advocates' recommended capital forecast reductions are based on speculation that PG&E will not be able to meet its forecasted "pace of work" (i.e., number of

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1817 PG&E-04, p. 10-1, lines 24-29.

1818 PG&E-17, p. 11-9, lines 14-16.

1819 PG&E-17, p. 11-9, lines 17-19.

1820 PG&E-04, p. 11-1, lines 15-17.

units forecasted to be completed) for Overhead and Underground Electric Distribution Maintenance activities due to other higher priorities, such as wildfire mitigation work.[1821] Cal Advocates further asserts that PG&E has not provided sufficient justification to show that PG&E's forecasted pace of work is necessary.[1822] To account for what it perceives will be the pace of work going forward, Cal Advocates recommends capping PG&E's forecasted units for 2021-2023 by using either 2019-2021 recorded units or 2018-2020 recorded units if 2021 data is unavailable or not representative.[1823]

The Commission should reject Cal Advocates' recommendations for three 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.

The maintenance work that Cal Advocates recommends limiting is generally considered compliance work, also referred to as "risk control" or "control" work. Controls are an essential element in managing the risk to PG&E's systems and are meant to maintain the current level of risk.[1824] Without an effective maintenance program, the risk to PG&E's system will increase. An effective maintenance program helps reduce asset risk by correcting identified hazards and degraded conditions.[1825] While PG&E has rescheduled some electric distribution maintenance work in the 2019-2021 period in order to address wildfire related work, it is inappropriate to apply a wholesale reduction to compliance work forecast in the 2023 GRC based on past work

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1821 Cal Advocates Opening Brief, pp. 184-187.

1822 Cal Advocates Opening Brief, p. 186.

1823 Cal Advocates Opening Brief, p. 186; CALPA-06, p. 20, line 14 to p. 22, line 5.

1824 PG&E's 2020 RAMP Report, A.20-06-012 (June 30, 2020), p. 3-24, lines 3-6.

1825 PG&E's 2022 Wildfire Mitigation Plan Update - Revised, OEIS Docket #2022-WMP (July 26, 2022), p. 537.

volumes, given the deleterious impact it would have on increasing system risks, both to safety and reliability.

In addition, Cal Advocates' argument, which is based on conditions that do not exist today, is speculative. Cal Advocates makes broad generalizations about PG&E's capacity to complete forecasted work based on its review of the PG&E's 2021 Risk Spending Accountability Report,[1826] which is reporting on work completed in 2021 and does not in any way address PG&E's capacity to do work in TY 2023 and future years. Cal Advocates concedes its speculation in its Opening Brief by caveating its assertions: "PG&E *may* have been able to achieve higher pace of work . . ., but *may* not be able to continue doing so . . ."[1827] The Commission should not reduce PG&E's forecast based upon unsubstantiated speculation, when the evidence presented demonstrates that PG&E will have the capacity to complete the work barring unforeseen events. As explained in testimony, PG&E has continued to evaluate and align resources to complete work as efficiently as possible. This resource-alignment effort includes establishing a project management organization (PMO)[1828] that is staffing a dedicated system hardening team and eliminating the need to move resources away from other work to support system hardening.[1829] It would be unreasonable to reduce PG&E's forecast based on Cal Advocates' speculation about a resource-constrained history that no longer exists.

Finally, PG&E provided sufficient justification for its forecast work in testimony, workpapers, and discovery regarding the capital programs at issue, explaining both the importance of the work for safety and reliability and why the forecasted pace of work is necessary.[1830] The programs and associated pace of work is reasonable because it is based on

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1826 Cal Advocates Opening Brief, p. 185; CALPA-06, p. 21, lines 1-7.

1827 Cal Advocates Opening Brief, p. 187 (emphasis added).

1828 PG&E-17, p. 4.3-18, line 21 to p. 4.3-26, line 31, Section C.4.

1829 PG&E-17, p. 11-8, lines 18-21.

1830 PG&E-04, Ch. 11; PG&E-04, WP Ch. 11.

regulatory requirements, PG&E standards and guidelines, and risk information and prioritization.[1831] Notably, Cal Advocates does not dispute that the work needs to be completed.

4.11.3 PG&E Appropriately Forecast Costs Based On The Most-Recent Costs

Cal Advocates' and TURN's Opening Briefs recommend forecast reductions based on unit cost information that ignores or removes 2019-2020 costs in several instances. It is not appropriate to base a forecast on inapplicable or selective cost information that does not reflect current market conditions and the work plan presented in the forecast. The more-recent 2019-2020 unit cost data reflects current circumstances and should be used as the basis of the forecast.[1832]

TURN argues that the removal of 2019-2020 costs is justified because the costs for the years are higher due to alleged PG&E imprudence when completing inspections pre-WSIP (before 2019). TURN generally claims that these alleged inspection failures have resulted in a cost premium for the work now required to address a backlog of damaged assets identified during the enhanced WSIP inspections. There is no evidence that inspection failures led to a cost-premium associated with the remediation work now required. To be sure, under WSIP, PG&E issued tags at approximately four times the average annual inspection find rate in pre-WSIP years.[1833] But this is a result of WSIP being a more rigorous inspection program to address wildfire risks, not past inspection failures. While the increased find rate has created a maintenance backlog that PG&E intends to address during this GRC cycle, PG&E's decision to apply stricter inspection criteria beyond GO 165 requirements was prudent so that it could more effectively address wildfire risks. In addressing the backlog so far, PG&E has appropriately

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1831 PG&E-04, p. 11-38, lines 1-4.

1832 PG&E-17, p. 11-11, lines 14-17; p. 11-13, lines 20-22.

1833 PG&E-17, p. 11-10, lines 19-21.

focused work execution on the highest wildfire risk tags and managed the volume of lower risk tags through other safety controls.[1834]

4.11.4 PG&E's Forecasts For Disputed MWCs And MATs Are Reasonable

4.11.4.1 PG&E's Expense Forecast For Overhead Preventive Maintenance (MWC KA) Is Reasonable

PG&E's TY 2023 expense forecast for Overhead Preventive Maintenance (MWC KA) presented in rebuttal testimony is $74.135 million, which consists of costs for the following MATs: Overhead Notifications (MAT KAA), Overhead COE (MAT KAF), Streetlight Burnouts (MAT KAH), and Other (MATs KAC, KAD, KAK, KAM, KAO, KAQ, KAS, KAP, and KA#).[1835] These forecasts are subject to escalation as proposed in PG&E's September, 2022 update. The programs involve the replacement of degraded or damaged equipment identified through PG&E's electric asset inspections.

TURN recommends reducing PG&E's MAT KAA expense forecast based on using the average recorded unit cost from 2016 to 2018 to forecast expenditures for 2023.[1836] TURN notes that the unit costs for this program doubled and tripled in 2019 and 2020, respectively, and argues that customers should not pay a premium based on 2019-2020 costs for a maintenance backlog that it alleges was caused by PG&E's prior inspection failures.[1837]

TURN's allegation is misplaced to the extent it seeks to make PG&E responsible for increased costs due to changing market conditions.

Supply chain issues and inflationary pressures are widely impacting many industries. PG&E's efforts to prioritize wildfire risk reduction are reasonable, and PG&E should not be penalized for changing economic and market conditions that have recently increased unit costs.

1834 PG&E's Revision Notice Response, RN-PG&E-022-05, OEIS Docket # 2022-WMP (July 11, 2022).

1835 PG&E-17, p. 11-3, Table 11-1, lines 1-4; p. 11-37, Table 11-4, lines 1-4.

1836 TURN-09, p. 34, lines 4-7.

1837 TURN-09, p. 33, lines 6-10.

Further, TURN uses selective and out of date 2016-2018 unit-cost data[1838] to develop a unit cost forecast of $839 for this program.[1839] It is not appropriate to base a forecast on cost information that does not reflect current market conditions and the work plan presented in the forecast. The more recent 2019-2020 unit cost data reflects current circumstances and should be included in the basis of the forecast.[1840] Moreover, the work PG&E plans for 2023 and future years will be based on its risk-informed inspections under WSIP since 2019 and is therefore different in scope and magnitude than the time-based inspection and repair/replacement work completed pre-WSIP in 2016-2018.[1841]

4.11.4.2 PG&E's Capital Forecast For Overhead Equipment Replacement (MWC 2A) Is Reasonable

PG&E uses MWC 2A to record capital expenditures for Overhead Equipment Replacement.[1842] Cal Advocates and TURN both recommend forecast reductions for the following MAT within MWC 2A: Overhead Notifications (MAT 2AA).

Cal Advocates also recommends forecast reductions for six additional MATs within MWC 2A: (1) Bird Safe Installation and Replacement (MAT 2AB); (2) Bird Safe Retrofit (MAT 2AC); (3) Overhead Idle Facilities Removal (MAT 2AF); (4) Overhead Capital Projects (MAT 2AP); (5) Ceramic Post Insulator Replacement (MAT 2AQ); (6) FAS Overhead Replacement (MAT 2AS).

TURN also recommends forecast reductions for one additional MAT within MWC 2A: Non-Exempt Surge Arrester Replacement (MAT 2AR).

PG&E addresses the parties' specific contentions regarding each of these MATs in the subsections below.

1838 TURN-09, p. 34, lines 4-6.

1839 PG&E-04, WP 11-10, Table 11-10, line 17.

1840 PG&E-17, p. 11-11, lines 14-17; p. 11-13, lines 20-22.

1841 PG&E-17, p. 11-13, lines 20-22.

1842 PG&E-04, p. 11-2, Table 11-2, line 6.

4.11.4.2.1 PG&E's Capital Forecast For Overhead Notifications (MAT 2AA) Is Based On Current Expected Costs

PG&E's capital forecast for Overhead Notifications (MAT 2AA) presented in rebuttal testimony is $232.990 million in 2021, $201.316 million in 2022, $205.363 million in 2023, $212.044 million in 2024, $218.717 million in 2025, and $230.716 million in 2026. These forecasts are subject to escalation as proposed in PG&E's September 2022 update. MAT 2AA tracks capital replacement work to address overhead maintenance conditions identified by PG&E's electric asset inspection program.[1843]

Both Cal Advocates and TURN recommend forecast reductions based on reducing the average unit costs used to calculate the forecast.[1844] In its Opening Brief, Cal Advocates explains that it does not oppose PG&E's proposed pace of work (i.e., the amount of units forecast),[1845] but reiterates its proposal to reduce unit costs based upon inapposite 2016-2018 cost data.[1846] Cal Advocates does not offer a reason for using 2016-2018 data other than to observe that doing so reduces PG&E's forecast. In its Opening Brief, TURN also proposes using average recorded unit cost from 2016-2018.[1847] In support, TURN argues that customers should not pay a premium that allegedly results from PG&E's maintenance backlog due to PG&E's WSIP activities.[1848]

The Commission should reject Cal Advocates' and TURN's adjusted forecasts for the same reasons discussed above in regard to the MAT KAA forecast. Both Cal Advocates and TURN propose forecast reductions based on cost information that does not reflect current market conditions or the planned work. The more-recent 2019-2020 unit cost data used by PG&E

1843 *See* PG&E-04, Ch, 10, which discusses PG&E electric distribution inspection activities.

1844 Cal Advocates Opening Brief, p. 193; TURN Amended Opening Brief, pp. 451-452; CALPA-06, p. 31, Table 6-12; TURN-09, p. 33, lines 13-15.

1845 Cal Advocates Opening Brief, pp. 193-194.

1846 Cal Advocates Opening Brief, p. 194; CALPA-06, p. 29, lines 13-17.

1847 TURN Amended Opening Brief, p. 455; TURN-09, p. 34, lines 4-7.

1848 TURN Amended Opening Brief, pp. 452-455; TURN-09, p. 33, lines 9-10.

reflects current circumstances and is a better basis for the forecast.[1849] Moreover, PG&E's 2023 GRC forecast is aligned to work that was completed in 2019-2020, making these years an appropriate basis for the forecast.[1850]

In its Opening Brief, TURN alleges that during the course of the proceeding, PG&E changed its explanation regarding the cost increases recorded in 2019-2020 and that the Commission should give PG&E's subsequent explanations no weight.[1851] This is an inaccurate characterization and the Commission should consider all the evidence presented in this proceeding. TURN notes that in one data response, PG&E explained that the cost increases observed in 2019-2020 could be attributed to the use of contractor and overtime resources to address the notifications.[1852] In rebuttal testimony and subsequent data responses, PG&E further explained that cost increases also could be attributed to the fact that PG&E completed higher priority work in remote, difficult-to-access areas that cost more to address.[1853] There is no conflict in these explanations, and there is no reason for the Commission to ignore or discount PG&E's subsequent clarifications as urged by TURN.

Appearing to concede that there ultimately is no sound basis for not considering this evidence, TURN alternatively argues that PG&E cannot confirm whether and to what extent the more-costly higher priority work in difficult-to-access areas will continue.[1854] TURN reasons that lacking this confirmation, it is inappropriate to base the forecast on 2019-2020 costs.[1855] This also is not true. TURN ignores PG&E's rebuttal testimony on this point. As noted above,

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1849 PG&E-17, p. 11-13, lines 14-15.

1850 PG&E-17, p. 11-13, lines 16-19.

1851 TURN Amended Opening Brief, p. 453.

1852 TURN Amended Opening Brief, pp. 452-453.

1853 TURN Amended Opening Brief, p. 453.

1854 TURN Amended Opening Brief, pp. 453-454.

1855 TURN Amended Opening Brief, pp. 452, 454-455.

PG&E explained that its forecast is aligned to the work completed in 2019-2020. Put another way, PG&E confirmed in testimony that the work planned for this GRC period will continue to reflect higher-priority activities in remote areas that cost more to complete, making 2019-2020 cost information an appropriate basis for the forecast.[1856] The stale 2016-2018 cost information used by TURN and Cal Advocates simply does not reflect existing market conditions that continue to be impacted by supply chain issues and recent inflationary pressures. The Commission should approve using the most-recent cost information, not stale information that has no bearing on current circumstances.

Finally, contrary to TURN's allegations, PG&E did not imprudently create a maintenance backlog that caused unit costs to increase. As explained in Section 4.10, the backlog exists because of PG&E's prudent decision to enhance its inspection criteria in order to meaningfully address emerging wildfire risk. The higher costs recorded in 2019-2020 are more broadly due to changing economic and market conditions.

No party contends the work should not be completed; indeed, TURN acknowledges that "this work needs to be done."[1857] The Commission should approve the Overhead Notifications (MAT 2AA) forecast without adjustment so that PG&E is sufficiently funded to complete the work.

4.11.4.2.2 PG&E's Capital Forecast For Bird Safe Installation (MAT 2AB) Is Reasonable

PG&E's capital forecast for Bird Safe Installation (MAT 2AB) presented in rebuttal testimony is $$3.023 million in 2021; $3.481 million in 2022; $3.474 million in 2023; $3.481million in 2024; $3.487 million in 2025; and $3,494 million in 2026. These forecasts are subject to escalation as proposed in PG&E's September 2022 update. MAT 2AB tracks capital

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1856 PG&E-17, p. 11-13, lines 14-19.

1857 TURN Amended Opening Brief, p. 449.

modifications to distribution poles in response to bird incidents. It includes retrofit on the pole where the incident occurred and/or adjacent poles.[1858]

Cal Advocates recommends a forecast reduction by reducing PG&E's unit-cost forecast based again on stale 2016-2018 data,[1859] claiming that PG&E should be able to achieve lower unit costs through economies of scale.[1860] The Commission should reject this recommendation for similar reasons to those discussed above regarding the use of inapplicable cost information. Cal Advocates proposes using cost information that does not reflect current market conditions and work plans, in contrast to PG&E's unit-cost forecast based on recorded 2019-2020 costs for similar work.[1861]

Cal Advocates' argument that PG&E should be able to achieve lower costs through economies of scale is speculative and does not make sense in this situation. There is no evidence supporting Cal Advocates' contention that unit costs increased in 2019-2020 because PG&E reduced its scope of work in those years. Moreover, the more reasonable explanation presented by PG&E is that unit costs increased due to changing market conditions. It is reasonable to develop a forecast based upon the most-recent cost information reflecting current circumstances. The Commission should reject Cal Advocates' recommendation for MAT 2AB.

4.11.4.2.3 PG&E's Capital Forecast For Bird Safe Retrofit (MAT 2AC) Is Reasonable

PG&E's capital forecasts for Bird Safe Retrofit (MAT 2AC) presented in rebuttal testimony is $3.432 in 2021; $3.626 million in 2022; $3.615 million in 2023; $3.927 million in 2024; $3.938 million in 2025; and $3.949 million in 2026.[1862] These forecasts are subject to escalation as proposed in PG&E's September, 2022 update. MAT 2AC tracks capital

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1858 PG&E-04, p. 11-30, lines 3-17.

1859 Cal Advocates Opening Brief, p. 195; CALPA-06, p. 32, lines 6-8.

1860 Cal Advocates Opening Brief, p. 195.

1861 PG&E-17, p. 11-20, lines 9-11.

1862 PG&E-17, p. 11-38, Table 11-5, line 3 (PG&E's 2020-2026 recorded and forecast costs).

modifications to distribution poles as part of the annual program which requires selecting and retrofitting a minimum of 2,000 poles. Additionally, this program supports PG&E's commitment made to the US Fish and Wildlife Service to retrofit poles in raptor concentration zones to mitigate bird-related outages.[1863]

Cal Advocates recommends forecast reductions based upon lower unit costs by reducing the number of TY 2023 forecasted units and the associated unit cost.[1864] To reduce the forecast number of units, Cal Advocates extrapolates 2019-2021 pace-of-work information.[1865] Cal Advocates also recommends basing unit costs on 2017-2019 cost information, specifically removing 2020 costs as a supposed outlier year.[1866] The Commission should reject these recommendations for reasons similar to those discussed above for other MWC 2A programs.

By reducing the forecast units based on work completed in prior years, Cal Advocates ignored PG&E's testimony explaining PG&E's work plan to address more Priority B tags,[1867] which are issued when the condition of an asset is of moderate potential impact to safety or reliability and corrective action is required within 3 months from the date the condition is identified. Given the accelerated 3-month corrective-action window, PG&E will be completing more work in a given year than it has historically.

Cal Advocates claims that it is unclear whether PG&E must meet its forecasted work volume to meet its commitment to the US Fish and Wildlife Service or whether a lower pace would still be sufficient.[1868] There is no ambiguity. PG&E explained that the number of units

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1863 PG&E-04, p. 11-30, lines 18-28.

1864 Cal Advocates Opening Brief, p. 197; CALPA-06, p. 34, line 1.

1865 Cal Advocates Opening Brief, p. 197; CALPA-06, p. 33, lines 10-19.

1866 Cal Advocates Opening Brief, p. 197.

1867 PG&E-04, p. 11-30, lines 14-17.

1868 Cal Advocates Opening Brief, p. 197.

forecast for TY 2023 is based on compliance requirements and risk-based prioritization.[1869] The reduced pace of work recommended by Cal Advocates would jeopardize PG&E's ability to fulfill its regulatory commitment. A reduction also would be inconsistent with PG&E's risk-based work plans. It is inappropriate to compare a forecast number of units based on risk prioritization to an average number of units from prior years that were not based on a similar prioritization method. The Commission should reject Cal Advocates' recommendation for MAT 2AC.

4.11.4.2.4 PG&E's Capital Forecast For Idle Facilities Removal (MAT 2AF) Is Reasonable

PG&E's capital forecasts for Idle Facilities Removal (MAT 2AF) presented in rebuttal testimony is \$20.500 million in 2021; \$2.732 million in 2022; \$2.726 million in 2023; \$2.732 million in 2024; \$2.737 million in 2025; and \$2.742 million in 2026. These forecasts are subject to escalation as proposed in PG&E's September 2022 update. The MAT 2AF program involves removing (decommissioning) distribution infrastructure that is no longer necessary to serve customers.[1870] These facilities can pose a safety and wildfire threat to the extent they can inadvertently become energized.

Cal Advocates recommends reducing the unit cost for MAT 2AF to the values authorized in the 2020 GRC.[1871] In support, Cal Advocates argues that the higher unit costs used by PG&E to develop the forecast are based on PG&E's use of contractors, and that PG&E should avoid these higher cost by reducing its pace of work.[1872] The Commission should reject Cal Advocates' recommendation because it effectively reduces the amount of work PG&E can

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1869 PG&E-17, PG&E's response to Data Request CalAdvocates_090-Q04, dated 10/19/21, pp. App A-135 to App A-136.

1870 PG&E-04, p. 11-27, lines 5-15.

1871 Cal Advocates Opening Brief, p. 199; PG&E-04, WP 11-40, Table 11-36, line 9.

1872 Cal Advocates Opening Brief, p. 199.

complete.[1873] Reducing PG&E's idle facilities removal program would limit critical system hardening efforts in high-risk wildfire areas.[1874] The Commission should reject Cal Advocates' recommendation for MAT 2AF.

4.11.4.2.5 PG&E's Capital Forecast For Non-Wood Streetlights And Equipment With Access Issues (MAT 2AP) Is Reasonable

PG&E's capital forecast for Non-Wood Streetlights and Equipment with Access Issues (MAT 2AP) presented in rebuttal testimony is $1.943 million in 2021; $2.243 million in 2022; $2.243 million in 2023; $1.943 million in 2024; $1.943 million in 2025; and $1.943 million in 2026. These forecasts are subject to escalation as proposed in PG&E's September 2022 update. The Non-Wood Streetlight Replacement program replaces streetlight-only poles installed prior to 2005 that have an unacceptable level of corrosion.[1875] The Equipment with Access Issues program involves relocating equipment where line workers have identified hazards in accessing equipment at its current site.[1876] Both programs are tracked and recorded in MAT 2AP.

For the Non-Wood Streetlight Replacement program, Cal Advocates reiterates its objection regarding PG&E's forecasted pace of work[1877] and recommends a funding level equal to the escalated average capital expenditures for 2019-2021.[1878] Cal Advocates' recommended funding levels are inadequate and would compromise PG&E's safety objectives for program. Indeed, Cal Advocates proposes nearly a 30 percent reduction, which they characterize inaccurately as "virtually no change."[1879] Replacing non-wood streetlight poles, however,

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1873 PG&E-17, p. 11-23, line 13-16.

1874 PG&E-17, p. 11-23, lines 12-13.

1875 PG&E-04, p. 11-26, line 15 to p. 11-27, line 3.

1876 PG&E-04, WP 11-35, Table 11-31, line 14.

1877 Cal Advocates Opening Brief, p. 205; CALPA-06, p. 43, lines 8-10.

1878 Cal Advocates Opening Brief, p. 205; CALPA-06, p. 43, lines 13-14.

1879 Cal Advocates Opening Brief, p. 205; CALPA-06, p. 43, Table 6-20 (percent change calculated as: ($1,028-$743)/$1028 = 28% and ($1,028-$763)/$1,028 = 26%); p. 43, lines 6-7.

mitigates a public safety risk of catastrophic streetlight pole failures due to corrosion or damage.[1880] Reducing PG&E's forecast by nearly 30 percent is unreasonable in light of this public safety risk.

In regard to the Equipment With Access Issues program, Cal Advocates recommends authorizing a budget equal to the escalated average of 2016-2018 because PG&E had no program expenditures in 2019 or 2020.[1881] If adopted, Cal Advocates' recommendation would reduce PG&E's funding by more than half.[1882] Cal Advocates speculates that there is no reason for PG&E to expect to have more issues on its system than it did from 2016-2018.[1883] The Commission should reject this speculative reasoning. PG&E explained that its forecast is based on anticipated emergent work[1884] given known hazards identified by PG&E electrical engineers and planning experts. It is not reasonable to use PG&E's 2016-2018 work volume rather than PG&E's current engineering judgment regarding the scope of work that will be required going forward.

4.11.4.2.6 PG&E's Capital Forecast For Ceramic Post Insulators (MAT 2AQ) Is Reasonable

PG&E's capital forecast for Ceramic Post Insulators (MAT 2AQ) presented in rebuttal testimony is $3.960 million in 2021; $5.832 million in 2022; $5.821 million in 2023; $5.832 million in 2024; $5.843 million in 2025; and $5.855 million in 2026. The MAT 2AQ program replaces Ceramic Post Insulators manufactured prior to 1972.[1885] These forecasts are subject to escalation as proposed in PG&E's September, 2022 update.

1880 PG&E-04, WP 11-54.

1881 Cal Advocates Opening Brief, p. 204; CALPA-06, p. 41, lines 10-13.

1882 CALPA-06, p. 42, lines 1-3 and Table 6-19.

1883 CALPA-06, p. 41, lines 7-8.

1884 PG&E-17, PG&E's response to Data Request CalAdvocates_028-Q10, dated 9/7/21, p. App A-132.

1885 PG&E-04, p. 11-29, line 1 to p. 11-30, line 2.

Cal Advocates recommends reducing the forecast 2023 pace of work for the program to the 2019-2021 pace of work,[1886] resulting in a reduction of approximately 80 percent.[1887] The reduction is unwarranted. In rebuttal testimony, PG&E explained that it is increasing the pace of work from 2022-2026 due to its plans to increase replacement activities in Tier 2/Tier 3 HFTD areas.[1888] The ceramic post insulators that will be replaced under this program are old, nearing 50 years in service as noted above. If not timely replaced, they may fail at lower-than-rated cantilever strength or altogether fail to adequately insulate electric current, presenting both a safety and reliability risk.[1889] Cal Advocates does not offer any additional rationale for the proposed reduction other than reducing the pace of work to a lower level. Adopting Cal Advocates' proposal to reduce the number of Ceramic Post Insulators replaced by more than 80 percent in 2023 would significantly reduce the risk reduction afforded by this mitigation. The Commission should reject the proposal and adopt PG&E's forecast for MAT 2AQ.

4.11.4.2.7 PG&E's Capital Forecast For Field Automation System Overhead Replacement (MAT 2AS) Is Reasonable

PG&E's capital forecast for Field Automation System Overhead Replacement (MAT 2AS) presented in rebuttal testimony is \$0.639 million in 2021; \$0.831 million in 2022; \$0.830 million in 2023; \$0.831 million in 2024; \$0.833 million in 2025; and \$0.835 million in 2026. This forecast is subject to escalation as proposed in PG&E's September, 2022 update. This program involves capital work identified during field work completed by a single troubleshooter. The work could be replacements or installations of overhead facilities such as

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1886 Cal Advocates Opening Brief, pp. 201-202.

1887 PG&E-17, p. 11-28, lines 19-23.

1888 PG&E-17, PG&E's response to Data Request CalAdvocates_090-Q04, dated 10/19/21, pp. App A-135 to App A-136.

1889 PG&E-04, p. 11-29, lines 5-7.

electric distribution conductors, components, structures and associated equipment constructed above ground level.[1890]

Cal Advocates recommends reducing the forecast based on using PG&E's average pace of work from 2017-2019.[1891] Cal Advocates claims that there is no reason why PG&E should expect the field automation system to have more issues than the historical norm.[1892]

PG&E explained that its forecast is based on PG&E engineers' best estimate about how the system is functioning today and what replacement level will be needed to sustain performance.[1893] To revert to the number of units from prior years, contrary to these system experts' judgment, is unreasonable. The Commission should reject Cal Advocates' recommendation for MAT 2AS.

4.11.4.2.8 PG&E's Capital Forecast For Non-Exempt Surge Arrester Replacement (MAT 2AR) Is Reasonable

PG&E's capital forecasts for Non-Exempt Surge Arrester Replacement (MAT 2AR) presented in rebuttal testimony is $88.859 million in 2021; $16.804 million in 2022; $17.759 million in 2023; $35.472 million in 2024; $36.429 million in 2025; and $37.413 million in 2026. These forecasts are subject to escalation as proposed in PG&E's September, 2022 update. This program involves replacing non-exempt surge arresters with exempt surge arresters and corrects abnormal grounding issues where necessary.[1894]

TURN's primary recommendation is to provide no funding for this program.[1895] TURN argues three points in support: (1) PG&E has already received funding for the program in the 2017 GRC; (2) PG&E is partly responsible for the defective grounding and has not demonstrated

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1890 PG&E-04, WP 11-44, Table 11-40, line 3.

1891 Cal Advocates Opening Brief, p. 203; CALPA-06, p. 42, Table 6-19.

1892 Cal Advocates Opening Brief, p. 203; CALPA-06, p. 40, line 21 to p. 41, line 3.

1893 PG&E-17, p. 11-32, lines 14-16.

1894 PG&E-04, p. 11-27, line 25 to p. 11-28, line 29.

1895 TURN Amended Opening Brief, p. 456; TURN-09, p. 30, Table 2.

the benefits of correcting the defects; and (3) replacing surge arrestors in non-HFTD areas provides limited safety benefit.[1896] The Commission should reject each of these arguments for the reasons described below.

1. PG&E Could Not Use Expense Funding For Capital Work

The fact that PG&E did not spend previous GRC-authorized *expense* funding for the program should not disqualify its *capital* funding request in this GRC. As PG&E explained in its rebuttal testimony in the 2020 GRC in response to this same argument (not ruled upon due to an eventual proceeding-wide settlement), when the scope of the surge arrester program changed from a stand-alone grounding correction program to a combined grounding and replacement program, it became appropriate to capitalize the work.[1897] As a result, PG&E could not and did not spend the *expense* amounts authorized in the 2017 GRC for *capital* work under the Surge Arrester Grounding program (MAT KAR) or the new Non-Exempt Surge Arrester Replacement Program (MAT 2AR).[1898] Changes in spending due to changes in program scope and accounting treatment are a routine part of test-year forecast ratemaking. In addition, in some circumstances adopted amounts exceed actual spending and other times actual spending is higher than adopted amounts. It would not be equitable to penalize PG&E for its expense underspending here when it is not credited for expense overspending in this or other years for other programs.

2. PG&E Followed Commission Guidance Regarding The Grounding Work And The Benefit Of Correcting The Grounding Work Is Reduced Fire Risk

TURN's argument that PG&E was responsible for defective grounding ignores the regulatory history on this issue. PG&E followed Commission guidance regarding this grounding work; PG&E should not be penalized in hindsight for following guidance that was reasonably

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1896 TURN Amended Opening Brief, pp. 456-459.

1897 A.18-12-009, HE-20: Exhibit (PG&E-18), p. 6-23, lines 22-25.

1898 PG&E-17, p. 11-15, lines 16-19.

provided by the Commission at that time. Specifically, in 1974, PG&E met with the Commission and proposed eliminating the isolating gap and connecting non-tank-mounted[1899] surge arresters and transformer neutrals together and grounding them through a single solid connection to the ground (also known as a "common ground"). PG&E sought guidance regarding whether this proposed change complied with Rule 33.3(b) of GO 95. As documented in a PG&E memorandum memorializing the meeting, the Commission agreed with the proposed change based on its interpretation of Rule 33.3(b) of GO 95.[1900] In 2006, PG&E sought guidance from the Commission again, in response to an allegation in a lawsuit that PG&E's use of a common ground violated GO 95. This time Commission staff concluded that common ground installations were not compliant with GO 95, except in certain limited circumstances.[1901]

As it did in the 2017 and 2020 GRC, TURN recommends a disallowance of 20 percent of non-tank mounted grounding work, rather than 100 percent, "because CPUC staff did support PG&E's erroneous proposed practices."[1902] TURN, however, recommends that 100 percent of PG&E's expenditures for correcting the grounding of tank-mounted surge arresters be recorded below the line and/or removed from rate base on the basis that the Commission's 1974 guidance supposedly only applied to non-tank mounted surge arresters.[1903] But, as PG&E explained in

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1899 Surge arresters are either tank-mounted (i.e., mounted on the side of transformer tank) or non-tank-mounted (i.e., mounted on a cross-arm or bracket above the transformer). PG&E is not aware of any technical reason to maintain different grounding configurations for tank-mounted vs. non-tank-mounted surge arresters. *See* A.15-09-001, PG&E's response to Data Request TURN_069-Q25(f), dated 4/8/16, pp. App A-389 to App A-390.

1900 A Commission memo from the same meeting stated that Commission staff "could find nothing in G.O. 95 requiring the spark gap device." *See* A.15-09-001, PG&E's response to Data Request TURN_009-Q03Rev01 and Attachments TURN_009-Q03Atch01 and Atch02, dated 4/6/16, pp. App A-214 to App A-217.

1901 A.15-09-001, Exhibit (PG&E-23), p. 6-10, lines 11-32.

1902 TURN-09, p. 38, lines 11-13.

1903 TURN-09, p. 38, lines 4-8.

testimony, there is no functional difference between tank-mounted and non-tank-mounted surge arrestor from the perspective of grounding.[1904] Therefore, PG&E reasonably followed the Commission's guidance for both non-tank-mounted and tank-mounted surge arrestors. This was not PG&E making an error in judgment; this was PG&E attempting to ensure its compliance with GO 95 and following Commission guidance. PG&E only went forward with common grounding of surge arresters after receiving an interpretation from Commission staff that Rule 33.3(b) permitted the change. PG&E should not be penalized for following the Commission's guidance regarding Rule 33.3(b).

In regard to TURN's argument that PG&E has not demonstrated the value of correcting the defective grounding, TURN cannot have it both ways. TURN seeks to disallow costs on the grounds that PG&E was imprudent in connection with defective grounding work. The allegation of imprudence falls flat, however, to the extent TURN also tries to suggest there is no apparent benefit to correcting the grounding work (i.e., no negative consequence caused by the alleged imprudence). In any event, PG&E was not imprudent for the reasons discussed above. And the benefit in correcting the grounding work is reduced fire risk.

3. Replacing Non-Exempt Surge Arrestors Reduces Fire Risk

Finally, TURN's suggestion that replacing non-exempt surge arrestors in non-HFTD areas has little benefit is wrong. Indeed, it is contrary to the findings of California state agencies. Non-exempt surge arresters are a known fire risk, which is why the California Department of Forestry and Fire Protection includes them on the list of equipment subject to PRC § 4292.[1905] That risk is present on all poles, albeit to a lesser extent, outside the HFTD areas.[1906] Installing exempt surge arresters is a prudent mitigation of the fire risk; when a non-exempt surge arrester fails due to thermal overload, the arrester failure can produce hot particles, including metals,

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1904 PG&E-17, p. 11-18, lines 16-18.

1905 PG&E-17, p. 11-18, lines 25-27.

1906 PG&E-17, p. 11-18, lines 27-28.

capable of starting a fire in the presence of fuel.[1907] Vegetation management under poles with non-exempt equipment reduces risk, but it does not eliminate it; for example, wind can blow the particles outside the perimeter that is cleared as part of the PRC §4292 compliance requirement.[1908]

What is more, the Commission agreed that the replacement program provides wildfire-risk-mitigation benefits. In adopting the 2020 GRC Settlement Agreement in its final decision on the 2020 GRC, the Commission found that replacing non-exempt surge arresters mitigates fire risk in HFTDs and non-HFTDs.

> While not identified as a top risk, replacement of non-exempt surge arresters serves to mitigate fire risk in HFTD and also non-HFTD areas. In this case, we find it prudent to give due regard to the agreement reached by the settling parties to adopt PG&E's proposed capital forecasts for EDM for 2019 and 2020 as the settling parties include both TURN and Cal Advocates.[1909]

The Commission should reject TURN's recommended disallowances as unsupported. TURN has offered no compelling reasons why arguments it raised in the 2017 and 2020 GRCs should not be rejected again. The Commission should adopt PG&E's forecast for Surge Arrestor Replacements (MAT 2AR).

4.11.4.2.9 Other MAT 2A Forecast Issues

Cal Advocates' Opening Brief discusses two new recommended forecast reductions to MAT activities (MAT 2AH and MAT 2AG) not addressed in PG&E's Opening Brief as disputed issues.[1910] PG&E responds to these recommendations below.

First, in its Opening Brief, Cal Advocates recommends nearly a 95% forecast reduction to remove $6.7 million of PG&E's $7.1 million 2023 capital expenditure forecast for PG&E's LED Conversion program (MAT 2AH). In errata to its testimony, Cal Advocates indicated that

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1907 PG&E-17, p. 11-19, lines 1-4.

1908 PG&E-17, p. 11-19, lines 4-7.

1909 D.20-12-005, p. 98 (emphasis added).

1910 Cal Advocates Opening Brief, pp. 199-200.

they did not oppose PG&E's capital forecasts for this program.[1911] Cal Advocates does not explain the discrepancies in these positions, and PG&E believes that Cal Advocates' Opening Brief errs in identifying a recommended forecast reduction. In any event, PG&E's rebuttal testimony explains that the LED conversion program improves system reliability and public safety because there will be fewer streetlight burnouts given that LED lights have longer 20-year service lives in comparison to HPSV bulbs, which only have service lives of approximately 4 to 5 years; in addition, lighting conditions will be improved because LED lights produce more consistent light output HPSV bulbs.[1912] The expenditures are reasonable given these benefits. The Commission should adopt PG&E's forecast without any reductions, consistent with PG&E's testimony and Cal Advocates' statement in its errata to testimony.

Cal Advocates also indicates that it proposes "virtually no change" for PG&E's Regulated Output (RO) Streetlight Replacement program (MAT 2AG), but recommends a reduction of $2.7 million for the 2021 forecast.[1913] Again, PG&E does not dispute a reduction based on actual 2021 recorded capital expenditures as long as the true-up for recorded costs is for all programs, and is not selectively requested only where the 2021 recorded costs are lower than PG&E's 2021 forecast.[1914]

4.11.4.3 PG&E's Capital Forecast For Underground Equipment Replacement (MWC 2B) Is Reasonable

PG&E uses MWC 2B to record capital expenditures for underground preventive maintenance. Cal Advocates recommends forecast reductions for the following programs within

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1911 CALPA-06-E, List of Revisions ("Cal Advocates previously opposed PG&E's request for MAT 2AH: LED Streetlight Conversions. However, Cal Advocates has identified that its opposition to the pace of work of PG&E's request was due to a typographical error in Cal Advocates' workpapers. Cal Advocates no longer opposes PG&E's request. Cal Advocates' reasoning and cost adjustments on these pages have been struck out.")

1912 PG&E-17, p. 11-25, lines 16-20.

1913 Cal Advocates Opening Brief, p. 205.

1914 PG&E Opening Brief, pp. 20-21.

PG&E's capital forecast for MWC 2B: (1) Underground Notifications (MAT 2BA); and (2) Underground Critical Operating Equipment (MAT 2BD). PG&E's addresses Cal Advocates' specific contentions below.

4.11.4.3.1 PG&E's Underground Notifications (MAT 2BA) Capital Forecast Is Reasonable

PG&E's capital forecast for Underground Notifications (MAT 2AR) presented in rebuttal testimony is $46.680 million in 2021; $46.391 million in 2022; $47.807 million in 2023; $49.171 million in 2024; $53.333 in 2025; and $54.773 million in 2026. This forecast is subject to escalation as proposed in PG&E's September, 2022 update. Work tracked in MAT 2BA improves system reliability and safety, and ensures regulatory compliance, by correcting abnormal maintenance conditions related to PG&E's underground facilities.[1915]

Cal Advocates recommends reducing PG&E's MAT 2BA forecast based on reducing unit costs by using the average 2016-2018 recorded unit cost to forecast capital expenditures.[1916] As explained in several sections above, it is not appropriate to base a forecast on cost information that does not reflect current market conditions or the work plan presented in the forecast. The 2019-2020 unit-cost data used by PG&E reflects current circumstances and should be used as the basis of the forecast.

As PG&E explained in rebuttal testimony, unit costs for MAT 2BA started increasing in 2018 because of additional work for known regulatory tags ("F Priority"), which were identified during the 2014-2017 timeframe to be completed in the 2018-2020 timeframe.[1917] Cal Advocates suggests that PG&E can achieve lower unit costs by reducing contractor and overtime costs.[1918] But Cal Advocates misunderstands the principal cost drivers that are unavoidable.

1915 PG&E-04, p. 11-33, line 21 to p. 34, line 16.

1916 Cal Advocates Opening Brief, p. 207; CALPA-06, p. 45, lines 17-19.

1917 PG&E-17, PG&E's response to Data Request TURN_128-Q04, dated 3/4/22, p. App A-139.

1918 Cal Advocates Opening Brief, p. 207.

The forecast work for MAT 2BA includes increasing work on primary enclosures (larger enclosures that contain high-voltage cables), as opposed to secondary enclosures (smaller enclosures that contain low-voltage cables).[1919] Primary enclosures require more excavation than secondary enclosures and generally cost more to replace, which contributes to higher average unit costs starting in 2018.[1920] Accordingly, PG&E's use of more recent 2019-2020 cost information to determine unit costs is reasonable. The Commission should reject Cal Advocates' recommendation for MAT 2BA.

4.11.4.3.2 PG&E's Underground Critical Operating Equipment (MAT 2BD) Capital Forecast Is Reasonable

PG&E's capital forecast for Underground Critical Operating Equipment (MAT 2BD) presented in rebuttal testimony is $6.573 million in 2021; $6.354 million in 2022; $6.926 million in 2023; $7.113 million in 2024; $7.305 million in 2025; and $7.502 million in 2024. This forecast is subject to escalation as proposed in PG&E's September, 2022 update. The Underground Critical Operating Equipment program (Underground COE) is comprised of corrective maintenance of certain defined equipment.[1921]

Cal Advocates recommends reducing the MAT 2BD forecast based upon the average volume of work completed in 2018-2020.[1922] Cal Advocates fails to acknowledge 2020 as an outlier year that should not be included in the averaging methodology. MAT 2BD is comprised of reliability focused work but has lower priority than other maintenance work. In 2020, as a relatively lower-priority item, MAT 2BD work activities were impacted by COVID-19.[1923] Including a COVID-impacted 2020 work volume in an average to determine the 2023 unit forecast is inappropriate and results in an understated forecast not reflective of PG&E's work

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[1919] PG&E-17, p. 11-33, lines 14-17.

[1920] PG&E-17, PG&E's response to Data Request TURN_128-Q04, dated 3/4/22, p. App A-139.

[1921] PG&E-04, p. 11-35, line 23 to p, 11-36, line 11.

[1922] Cal Advocates Opening Brief, pp. 208-209; CALPA-06, p. 47, Table 6-23.

[1923] PG&E-17, p. 11-35, line 5.

plans.[1924] Instead, PG&E used a 2018-2019 two-year average of the find rate[1925] plus additional units for open or pending jobs. Further demonstrating the reasonableness of PG&E's forecast, the 144 units PG&E forecasts in 2023 is similar to the recorded number of units in 2016, 2017 and 2018.[1926] The Commission should reject Cal Advocates' recommendation for MAT 2BD.

4.11.5 Non-Financial Recommendations Regarding RSE Scores

Cal Advocates recommends that the Commission should require PG&E to provide more granular RSE scores at the individual MAT code program rather than at a mitigation or control code level.[1927] Cal Advocates states that this recommendation should be applied to all relevant MAT codes related to electric distribution infrastructure activities.[1928] PG&E addressed this recommendation in Section 2.3.3 of PG&E's Opening Brief.

4.12 Pole Asset Management

4.12.1 Overview

The Commission should approve PG&E's TY 2023 expense forecast for Pole Asset Management: (1) presented in rebuttal testimony as $39.340 million;[1929] and (2) presented in the JCE with the September escalation adjustment as $49.188 million.[1930]

The Commission should also approve PG&E's capital forecast for Pole Asset Management: (1) presented in rebuttal testimony as $311.884 million in 2021, $366.453 million in 2022, $379.514 million in 2023, $400.215 million in 2024, $400.989 million in 2025, and

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1924 PG&E-17, PG&E's response to Data Request CalAdvocates_028-Q04, dated 8/30/21, pp. App A-129.

1925 PG&E-04, p. 11-36, lines 1-3.

1926 PG&E-04, WP 11-48, line 12.

1927 CALPA-06, p. 27, lines 22-24.

1928 CALPA-06, p. 28, lines 5-7.

1929 PG&E-17, p. 12-3, Table 12-1, line 6.

1930 PG&E-64, p. 3-2, Table 3A-1, line 75.

$402.489 million in 2026;[1931] and (2) presented in the JCE with the September escalation adjustment as $321.540 million in 2021, $399.466 million in 2022, $428.667 million in 2023, $467.723 million in 2024, $469.907 million in 2025, and $461.161 million in 2026.[1932]

PG&E's electric distribution system includes approximately 2.3 million wood poles.[1933] PG&E's Pole Asset Management Program maintains the safety and reliability of wood pole assets through comprehensive inspection and repair/replacement programs.[1934]

Cal Advocates and TURN do not oppose PG&E's Pole Asset Management expense forecast but do recommend various reductions to PG&E's capital forecast for pole replacements. These recommendations, if adopted, would limit funding necessary to replace deteriorated and damaged poles that PG&E identified through WSIP as posing wildfire risk if not replaced.[1935] As explained further below, the proposed forecast recommendations are not justified, as they generally are based on Cal Advocates' and TURN's incorrect speculation that the volume of poles to be replaced has increased because PG&E has deferred pole-replacement work or failed to properly complete pole inspections in the past. This is not the case. PG&E's deferred work analysis submitted in this GRC demonstrated that there were no deferred pole replacements from the 2020 GRC.[1936] The increased volume of pole-replacement work is due to stricter criteria under the WSIP in order to mitigate wildfire risk, not prior inspection failures.

In the sections that follow, PG&E responds to Cal Advocates' and TURN's specific contentions in their respective Opening Briefs.

1931 PG&E-17, p. 12-14, Table 12-5, line 7.

1932 PG&E-67, WP 2, line "[Exhibit 4, Chapter] 12," MWC 07.

1933 PG&E-04, p. 12-9, lines 27-29.

1934 PG&E-04, p. 12-9, line 25 to p. 12-10, line 7.

1935 See Section 4.10 for additional information regarding the WSIP.

1936 PG&E-04, p. 12-33, lines 8-12.

4.12.2 PG&E's Capital Forecast For Install/Replace Overhead Poles (MWC 07) Is Reasonable

PG&E uses MWC 07 to record capital expenditures for Pole Asset Management. Cal Advocates and TURN both recommend forecast reductions for one MAT in MWC 07: Pole Replacement Program (MAT 07D).[1937]

Cal Advocates recommends forecast reductions for two additional MATs in MWC 07: (1) Overloaded Poles (MAT 07O); and (2) Center-Bore Streetlights/Tree Attachments (MAT 07C).[1938]

PG&E responds below to Cal Advocates' and TURN's recommended forecast reductions for the contested items.

4.12.2.1 PG&E's Forecasts For Pole Replacement Programs (MAT 07D, 07O and 07C) Are Reasonable

Under the Pole Replacement Program, MAT 07D activities involve replacing poles that are identified through PG&E's inspection programs as deteriorated, degraded, or damaged. MAT 07O is used for poles that are identified as potentially overloaded. MAT 07C covers replacements of tree attachments.[1939] PG&E's capital forecast and Cal Advocates' and TURN's recommended reductions for MAT 07D, 07O, and 07C are summarized below.

1937 Cal Advocates Opening Brief, p. 211, Table 2, line 2.

1938 Cal Advocates Opening Brief, p. 211, Table 2, lines 3 and 4.

1939 PG&E-17, p. 12-5, lines 13-16.

TABLE 4-30:
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)	$(31,835)			
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.							

Cal Advocates recommends reducing PG&E's overall capital forecast for the Pole Replacement Program.[1940] Cal Advocates suggests that PG&E historically has not adequately inspected and replaced when necessary distribution poles under the Pole Replacement Program,[1941] and further criticizes PG&E for having a history of deferring needed capital projects that had previously been authorized by the Commission.[1942] Cal Advocates argues the damaged poles would have been identified sooner had PG&E properly inspected them and not deferred replacement projects in years prior to 2019.[1943] Cal Advocates contends that in light of

1940 Cal Advocates Opening Brief, p. 221; CALPA-05, p. 16, Table 05-3.

1941 Cal Advocates Opening Brief, pp. 217-218; CALPA-05, p. 35, lines 27-30.

1942 Cal Advocates Opening Brief, p. 215; CALPA-05, p. 21, lines 8-10.

1943 Cal Advocates Opening Brief, p. 217; CALPA-05, p. 36, lines 5-9.

these alleged historical deficiencies, adjustments should be made to the forecast to exclude higher unit costs they claim could have been avoided had the degraded pole conditions been identified years sooner. Asserting that these higher unit costs are due to PG&E's use of contractors with overtime in 2019-2020 to work on the backlog,[1944] Cal Advocates calculates a proposed forecast reduction of $31.8 million.[1945]

Like Cal Advocates, TURN contends PG&E inspection process prior to WSIP was deficient and that there are various premiums attributable to PG&E's accelerated remediation work plans that customers should not have to pay.[1946] TURN proposes a reduction of $79.8 million to the 2022 and 2023 total-cost forecast for the Pole Replacement Program based on reductions to unit costs.[1947]

4.12.2.2 PG&E's Prior Pole Inspections Were Not Inadequate And There Is No Deferred Pole Replacement Work

Criticisms regarding PG&E's prior inspections also were addressed in Section 4.10, above. But it is important to address this issue again here more specifically to pole inspections. Both Cal Advocates and TURN reach a faulty conclusion by incorrectly correlating the current higher volume of pole maintenance items (including pole replacements) with supposed past inspection failures. The correct correlation is that the higher volume of pole maintenance/replacement items is due to PG&E's prudent decision to apply stricter inspection criteria in order to ensure that wildfire risks were being addressed sufficiently. Mitigating wildfire risk due to defective poles is particularly important given that the poles provide the foundation of the overhead distribution system. Given this function, it was critical for PG&E to change inspection criteria for poles in particular, as increasing wildfire risk had become evident

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1944 Cal Advocates Opening Brief, p. 220; CALPA-05, p. 36, lines 5-9; p. 36, line 26 to p. 37, line 4.

1945 CALPA-05, p. 16, Table 05-3.

1946 TURN Amended Opening Brief, pp. 460-461; TURN-09, p. 47, lines 4-14.

1947 TURN Amended Opening Brief, pp. 464-465; PG&E-17, p. 12-8, lines 8-12.

following the 2017 and 2018 northern California wildfires. To that end, in 2019, PG&E developed detailed and objective criteria for the GO 165 detailed visual inspections based on the asset wildfire risk analysis that was informed by a Failure Mode and Effects Analysis (FMEA).[1948] PG&E used this analysis to develop enhanced inspection criteria and initiate accelerated inspections of electric facilities in HFTDs to identify and repair non-conforming facilities (including non-conforming poles) that posed an ignition, safety, or reliability risk.[1949] Under the new inspection program (*i.e.*, WSIP), PG&E is now performing inspections at an accelerated rate and inspecting more assets, including poles, annually than had been inspected in the past.[1950] The new inspection program uses stricter criteria for completing the pole health assessment, resulting in a higher find-rate and increased volume of pole replacements than was historically the case.[1951]

Both 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. Cal Advocates' faulty reasoning goes as far to speculate, "[i]f PG&E is currently experiencing a 'higher find-rate and increased volume of pole replacements,' that simply indicates that PG&E failed to adequately inspect its poles in prior years."[1952] In other words, Cal Advocates essentially appears to argues that once damage is identified, this means the prior inspection must have been inadequate. Not so, and this faulty conclusion belies what is readily observable in the real world regarding how equipment damage (including wood damage) often manifests. As conceded by Cal Advocates in a data request regarding pole inspections, equipment found to be in satisfactory

1948 PG&E-17, p. 12-7, lines 2-5.

1949 PG&E-17, PG&E's response to Data Request TURN_120-Q02(a), dated 2/28/22, p. App A-142.

1950 PG&E-17, p. 12-7, lines 11-14.

1951 PG&E-17, p. 12-7, lines 14-16.

1952 Cal Advocates Opening Brief, p. 220.

condition during a given year's inspection could be found to be in a degraded condition requirement replacement soon thereafter,[1953] perhaps even within a few days, weeks, or months following the inspection due to any number of external factors beyond PG&E's control. Indeed, as Cal Advocates acknowledges, it is a "virtual certainty" that equipment inspected in any given year will eventually require replacement in some future year.[1954] In addition, the manifestation of pole degradation or failure that requires replacement can often appear suddenly without warning even after the pole was just inspected. This does not mean that the inspections prior to the pole replacements were inadequate. It only shows the importance of completing pole inspections on a regular basis.

Cal Advocates and TURN are dismissive of any explanation for the high-find rate other than their speculation that PG&E's prior pole inspections were inadequate, with Cal Advocates stating that it is "unlikely that over 100,000 distribution poles, previously safe and in compliance with GO 95 and other requirements, suddenly deteriorated and became unsafe in 2019"[1955] and TURN opining that "the number of pole tags is evidence of PG&E's prior inspection failures."[1956] Cal Advocates ignores that the 100,000 poles identified for replacement is just 4% of PG&E's 2.3 million distribution poles, making the total figure of pole replacements unalarming. TURN's tortuous review of historical find-rates prior to WSIP versus find-rates under WSIP is superficial, and is wrongly dismissive of PG&E's reasonable explanation that an increased time-horizon (look-ahead) for the inspection *combined with* stricter wildfire-risk-informed criteria led to a greater number of poles being identified for replacement, as opposed to prior inspection failures.

1953 PG&E-32, Cal Advocates' response to PG&E Data Request_PGE-CalAdvocates_016-Q01, dated 8/9/22.

1954 PG&E-32, Cal Advocates' response to PG&E Data Request PGE-CalAdvocates_016-Q01(c). dated 8/9/22.

1955 Cal Advocates Opening Brief, p. 219.

1956 TURN Amended Opening Brief, p. 460.

Further, it is reasonable to expect that equipment such as poles of similar installation vintage/location and subject to the same external stresses (extreme weather) could degrade and require replacement at roughly the same time. That is, a batching of higher-find rates for particular sets of poles at the same location should be of no surprise, particularly when applying a heightened inspection standard, because the poles are all subject to the same degradation-causing conditions. As an example, it would be reasonable to expect that if a car tire needs to be replaced due to wear, all tires on the car also would need to be replaced; this does not mean the tire inspections prior to the replacements were inadequate.

In addition, Cal Advocates' assertion that PG&E's backlog is due to deferred work is incorrect. There is no deferred work in the pole-replacement backlog at issue here. Indeed, as a required part of PG&E's showing, PG&E's deferred-work analysis did not identify pole replacements as deferred work.[1957] During cross-examination in evidentiary hearings, PG&E witness, Mr. Arvind Simhadri, confirmed that there was no deferred work contributing to the increased number of required pole replacements.[1958]

4.12.2.3 Cal Advocates' and TURN's Forecast Reductions Are Based On Inapplicable Cost Information And Ignores That Cost Drivers Are Beyond PG&E's Control

The Commission should also reject Cal Advocates' and TURN's recommendation to use pre-2019/2020 unit costs to derive a lower forecast. These proposals appear expressly designed to arrive at an artificially-lower forecast that ignores current market conditions and work plans.[1959] In contrast, PG&E uses an unbiased forecasting methodology utilizing the last three years of recorded costs (2018–2020) to calculate the capital forecasts for pole replacements.[1960]

1957 PG&E-04, p. 2-35, Table 2-5; *see also* A.18-12-009, HE-16: Exhibit (PG&E-04), p. 1-27, Table 1-4 (noting that pole replacements was not deferred work in the 2020 GRC as well).

1958 Tr. Vol. 7, 1228:8-19, PG&E/Simhadri.

1959 PG&E-17, p. 12-9, lines 4-6.

1960 PG&E-17, p. 12-9, lines 8-10.

PG&E's use of an averaging methodology is reasonable given that annual costs fluctuate from year to year with an overall upward trend. More importantly, the three-year average reflects existing market conditions and work plans.[1961] The trend line presented by Cal Advocates in its opening brief proves these points.[1962] Cal Advocates proposes unit cost based on 2018, as though unit costs became static as of then, notwithstanding a nearly annual upward trend in costs from 2013 to 2020. Indeed, using the last-year recorded as the basis for the forecast would have been justifiable given the year-over-year increase, but PG&E reasonably proposed using a three-year average of 2018-2020 costs.

Further, the cost increases driving PG&E's unit costs are due to external market factors, including higher labor and non-labor costs, disposal costs, and environmental/permitting costs.[1963] The increase of pole replacement costs in recent years can also be attributed to the locations of the pole replacements.[1964] PG&E 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 of more expensive equipment, including helicopters, large cranes or other heavy equipment, which adds significant cost to those replacements.[1965] PG&E expects to continue to replace poles in difficult-to-access locations, which require additional equipment, special permits and safety precautions.[1966] In addition, PG&E expects material costs to continue to increase.[1967]

1961 PG&E-17, p. 12-9, lines 17-19.

1962 Cal Advocates Opening Brief, p. 216, Graph 05-1.

1963 PG&E-17, p. 12-9, line 23 to p. 12-10, line 2.

1964 PG&E-17, p. 12-10, lines 3-4.

1965 PG&E-17, p. 12-10, lines 4-9.

1966 PG&E-17, p. 12-10, lines 9-11.

1967 PG&E-17, PG&E's response to Data Request TURN_120-Q10, dated 2/28/22, pp. App A-150 to App A-151.

TURN suggests that PG&E has not demonstrated the reasonableness of the unit costs used to develop the pole replacement forecast, because PG&E cannot precisely quantify various cost drivers that have caused unit costs to increase over time.[1968] PG&E is unaware of any such showing being required under the rate case plan, and such precision is unnecessary in light of PG&E's use of an averaging methodology to smooth-out variances. The principal issue to be decided by the Commission is what average better reflects current market conditions and costs. PG&E respectfully urges the Commission to determine that the more-recent 2018-2020 cost information used by PG&E better reflects current conditions and costs than the 2016-2017 cost information used by TURN.

Finally, Cal Advocates and TURN ignore that the unit costs used in PG&E's forecast reflect the meaningful actions PG&E implemented to reduce costs. PG&E conducted a Request for Proposal (RFP) process with multiple vendors to establish cost-competitive pricing for Distribution and Transmission Overhead and Underground work, which includes pole replacements. The RFP process encourages suppliers to manage their productivity and ensures that PG&E obtains favorable cost terms. The contracts were issued in April 2021 and resulted in significant savings in 2021 that PG&E anticipates will continue forward.[1969]

TURN and Cal Advocates ignore all of these factors and propose forecast reductions that would create resource constraints to complete the work. For the reasons discussed above, the Commission should reject Cal Advocates' and TURN's recommended disallowances and approve PG&E's Pole Replacement Program (MAT 07D, 07O and 07C) forecasts with zero disallowances.

4.12.3 Cal Advocates' Non-Financial Recommendations

Cal Advocates recommends that all pole replacement costs that are tracked under the Wildfire Mitigation Plan Memorandum Account (WMPMA) be removed from the capital

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1968 TURN Amended Opening Brief, pp. 461-463.

1969 PG&E-17, PG&E's response to Data Request TURN_120-Q05(a), dated 2/28/22, App A-145.

forecast in MWC 07.[1970] Cal Advocates is opposed to having PG&E's customers be financially responsible for the WMPMA forecast costs for pole replacement before the Commission has found that the actual expenditures are reasonable.[1971] PG&E addressed this issue in Section 10.4 of its Opening Brief.

4.13 Overhead And Underground Asset Management And Reliability

4.13.1 Overview

The Commission should approve PG&E capital expenditures forecast for the Overhead Asset Management (OAM), Underground Asset Management (UAM), and Reliability programs: (1) presented in rebuttal testimony as $153.720 million in 2021, $145.742 million in 2022, $164.438 million in 2023, $167.528 million in 2024, $171.152 million in 2025, and $176.895 million in 2026;[1972] and (2) presented in the JCE with the September escalation adjustment as $158.479 million in 2021, $158.871 million in 2022, and $185.735 million in 2023, $195.787 million in 2024, $200.568 million in 2025, and $202.682 million in 2026.[1973]

PG&E's OAM and UAM programs involves asset replacement for degraded or damaged components identified during PG&E's asset inspections.[1974] In addition to these asset replacement programs, PG&E implements a Reliability Program that involves adding additional distribution protection device zones or automated switching equipment to reduce or mitigate the number of customers impacted by future outages.[1975] The OAM, UAM, and Reliability

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[1970] Cal Advocates Opening Brief, pp. 212-214.

[1971] CALPA-05, p. 19, lines 12-14.

[1972] PG&E-17, p. 13-28, Table 13-4, line 23.

[1973] PG&E-67, WP-3, lines "[Exhibit 4, Chapter] 13," MWCs 08, 09, 49, 56, 2A and 2F.

[1974] PG&E-04, p. 13-5, lines 23-25; p. 13-6, lines 6-9.

[1975] The circuit zone reliability activities described in this Section are limited to non-HFTD areas only. For details of the circuit zone reliability work performed in HFTD areas, please refer to Chapter 4 of this exhibit.

programs improve the safety and reliability of PG&E's overhead and underground electric distribution system for the benefit of customers.

Cal Advocates and AARP recommend various forecast reductions in these programs. Many of Cal Advocates' recommendations do not dispute that the planned work is necessary, and instead are based on PG&E's prior pace of work when PG&E was resource-constrained while addressing emergent wildfire mitigation work, other higher-priority work, and the COVID-19 pandemic. Cal Advocates' proposed cuts do not reflect current circumstances and PG&E's resource and work plans. They should be denied. AARP argues that overhead conductor replacement is unnecessary in non-HFTDs, but largely ignores other safety and reliability issues. The Commission should reject AARP's recommendations as well.

In the sections below, PG&E responds to Cal Advocates' and AARP's specific contentions raised in their respective Opening Briefs.

4.13.2 The Commission Should Reject Cal Advocates' Pace-Of-Work Argument

As it does for other portions of PG&E's forecasts (such as overhead and underground maintenance activities discussed in Section 4.11), Cal Advocates continues to speculate in its Opening Brief that PG&E will not meet the forecasted "pace of work" (i.e., number of units forecasted to be completed) based on trends in prior years, and continues to recommend adjusting PG&E's forecasted units for 2021-2023 by using recorded values from prior years. In Section 4.11.2, PG&E explained why Cal Advocates' approach should not be adopted. Briefly reiterated here, the Commission should reject Cal Advocates' "pace of work" argument because: (1) limiting asset replacement work could increase electric system reliability and safety risks; (2) Cal Advocates bases its recommendations on speculation; and (3) PG&E has provided sufficient justification for all relevant programs.

Without an effective replacement program, the risk to PG&E's system will increase. An effective replacement program helps reduce asset risk by correcting identified hazards, degraded conditions, and non-standard equipment concerns.[1976] In addition, Cal Advocates' argument essentially is based on conditions that do not exist today. Cal Advocates makes its assertions based on its review of the PG&E's 2021 Risk Spending Accountability Report,[1977] which does not in any way address PG&E's capacity to do work in TY 2023. PG&E continues to evaluate and align resources to complete work and is eliminating the need to divert resources from its asset replacement and reliability work.[1978] Finally, PG&E provided sufficient justification for its forecast work in testimony, workpapers, and discovery regarding the capital programs at issue, explaining both the importance of the work for safety and reliability and why the forecasted pace of work is necessary.[1979]

4.13.3 The Commission Should Reject AARP's Recommendations As Counter To Sound And Prudent Utility Practices

AARP questions the cost effectiveness of replacing overhead conductors in non-HFTDs given that the fire risk is low and suggests that increasing the conductor replacement rate may be unnecessary.[1980] In making this recommendation and others like it (see discussion in Section 4.14), AARP appears to embrace a run-to-failure operations strategy that largely ignores safety and reliability issues. This approach to maintaining utility assets is unsound and creates safety risks. The Commission should reject AARP's recommendations that are based on run-to-failure principles.

1976 PG&E-04, p. 13-19, line 6 to p. 13-25, Table 13-6; PG&E's 2022 Wildfire Mitigation Plan Update - Revised, OEIS Docket #2022-WMP (July 26, 2022), p. 537.

1977 CALPA-06, p. 21, lines 1-7.

1978 PG&E-17, p. 13-9, lines 22-23.

1979 PG&E-04, Ch. 13; PG&E-04, WP Ch. 13; PG&E-17, p. 11-6, line 22 to p. 11-9, line 8.

1980 AARP-01, p. 51, line 13 to p. 52, line 11.

4.13.4 PG&E's Capital Forecast For Electric Distribution Overhead Asset Replacement (MWC 08) Is Reasonable

PG&E uses MWC 08 to record capital expenditures for Overhead Asset Management.

Cal Advocates and AARP both recommend forecast reductions for one program within PG&E's capital forecast for Electric Distribution Overhead Asset Replacement: Overhead Conductor Replacement Program (MAT 08J).

Cal Advocates recommends forecast reductions for one additional program in MWC 08: Grasshopper/Overhead Switch Replacements (MAT 08S).

Cal Advocates' and AARP's recommendations regarding these MATs are addressed in the subsections below.

4.13.4.1 PG&E's Capital Forecast For The Overhead Conductor Replacement Program (MAT 08J) Is Reasonable

MAT 08J tracks PG&E's proactive replacement of overhead conductor in non-HFTD areas to address elevated rates of wires down and deteriorated/damaged conductors, and to improve system safety, reliability, and integrity.[1981] PG&E's capital forecast for Overhead Conductor Replacement (MAT 08J) presented in rebuttal testimony is $41.180 million in 2021, $32.688 million in 2022, $43.036 million in 2023, $44.486 million in 2024, $45.701 million in 2025, and $46.934 million in 2026.[1982] This forecast is subject to escalation as proposed in PG&E's September, 2022 update.

Cal Advocates questions whether PG&E will achieve the pace of work assumed in PG&E's capital forecast for the Overhead Conductor Replacement Program and recommends $17.2 million for 2023 capital expenditures based on PG&E's recent work history from 2019-2021.[1983] The Commission should reject this recommendation for three reasons.

1981 PG&E-04, p. 13-28, lines 12-15.

1982 PG&E-17, p. 13-28, Table 13-4, line 1 (PG&E recorded and forecast costs).

1983 Cal Advocates Opening Brief, p. 224; CALPA-06, p. 52, lines 10-16 and 18-19.

First, the lower pace of work in prior years was reasonable at that time but should not continue. In 2019-2020, proactive conductor replacement in MAT 08J was lower due to various resource constraints and PG&E's focus on higher priority work in other programs such as major emergency, wildfire system hardening within Tier 2 and 3 HFTDs, pole replacements, emergency overhead conductor replacement, Public Safety Power Shutoff events, and other high-risk, time-dependent maintenance work.[1984] Later, in 2020 and 2021, the COVID-19 pandemic further required PG&E to defer MAT 08J work to protect the health and safety of workers and the public.[1985] While these deferrals were reasonable due to the exigent circumstances at the time, it would be imprudent to base future GRC funding for OAM activities on the prior resource-constrained pace of work that occurred from 2019-2021. Increased funding is necessary to address reliability issues as these assets age.

Second, Cal Advocates' proposed forecast reduction, which would provide less than half of PG&E's forecast, is insufficient for a program that is necessary to keep the electric distribution system reliable. While the Overhead Conductor Replacement Program is not specifically tied to wildfire safety, the program is fundamental to maintaining the reliability of the grid for customers.[1986] The proposed replacement levels will allow PG&E to address the conductors with the highest risk of failure.[1987] The replacement level is further supported by a 2018 study completed by the National Electric Energy Testing Research and Applications Center (NEETRAC) that concluded a significant annual increase of total conductor replacements would be needed to avoid increasing outage levels.[1988]

1984 A.18-12-009, PG&E's (Revised) Risk Spending Accountability Report (RSAR) (Sept. 23, 2020), p. 3-69, lines 23-30; PG&E-04, p. 13-54, line 10 to p. 13-55, line 5.

1985 PG&E-17, p. 13-12, lines 21-24.

1986 PG&E-17, p. 13-12, line 29 to p. 13, line 3.

1987 PG&E-17, p. 13-13, lines 7-10.

1988 PG&E-17, PG&E's response to Data Request CalAdvocates_027-Q02, Attachment CalAdvocates_027-Q02Atch01, dated 8/31/21, pp. App A-158, line 140 to App A-159, line 143.

Third, PG&E has met forecast replacement levels in the past and is positioned to do so during the GRC forecast period. In 2016, for example, PG&E completed the forecast replacement level of approximately 70 miles.[1989] Work plans have also been reprioritized to ensure resources are available to complete this work, with new risk assessment tools being developed to prioritize work.[1990] The 2016 replacement rate and PG&E's efforts to reprioritize its resources demonstrate that PG&E's planned replacement rate of 71.3 annual miles is achievable. In short, PG&E must replace more conductor, not less as recommended by Cal Advocates. PG&E's forecast is based upon reasonable and achievable replacement levels, and should be approved.

AARP argues for an approximately two-thirds forecast reduction on the ground that the program forecast is not cost-effective given the low fire risk in non-HFTDs.[1991]

The Commission should also reject AARP's recommendation as insufficient to maintain system reliability. AARP asserts that the 2018 NEETRAC study does not recommend the increased conductor replacement rate forecast by PG&E and instead recommends that more data be collected to guide proactive replacements and that increases can be ramped up over time, among other recommendations.[1992] AARP misreads the report, which, as noted above, states that a year-over-year increase in replacement rates is needed to maintain reliability:

> [T]to keep the present level of performance (a constant annual sustained outages), the total replacement length (reliability plus emergency & maintenance) needs to have a <u>significant year-over-year increase</u> along with a change in remediation strategy from repair to replace.[1993]

1989 PG&E-17, p. 13-13, lines 23-24.

1990 PG&E-17, p. 13-13, lines 25-27.

1991 AARP Opening Brief, pp. 30-31; AARP-01, p. 51, line 12 to p. 52, line 12.

1992 AARP Opening Brief, p. 30; AARP-01, p. 50, lines 6-9.

1993 PG&E-17, PG&E's response to Data Request CalAdvocates_027-Q02, Attachment CalAdvocates_027-Q02Atch01, dated 8/31/21, pp. App A-158, line 140 to App A-159, line 143 (emphasis added).

PG&E is following this guidance, including placing increased focus on overhead conductor replacements and on targeted analyses to identify those lines with the highest risk of failures. By arguing that PG&E should accept all other NEETRAC recommendations except the recommendation that recommends a significant year-over-year increase of replacements (not repairs), AARP appears to miss the point and is generally dismissive of the important role the Overhead Conductor Replacement Program has in ensuring system reliability. AARP's proposed reduction, which provides less than half of PG&E's forecast, will not provide sufficient funding for this reliability program.

AARP notes that PG&E routinely replaces conductor for a variety of reasons outside of the Overhead Conductor Replacement Program (such as accommodating new load, distributed energy resources (DER), etc.), and suggests that these other activities may make PG&E's Overhead Conductor Replacement Program duplicative.[1994] This is incorrect.

AARP's argument reflects a misunderstanding of the relatively narrow scope of these other conductor-installation activities. This other work is typically dictated by requirements unrelated to reliability.[1995] In contrast, PG&E's Overhead Conductor Replacement program focuses on replacing overhead conductor with the highest conductor and splice failure rates.[1996] Further reduction of overhead conductor replacement could present safety hazards as well as reliability issues for PG&E customers.

4.13.4.2 PG&E's Capital Forecast For Grasshopper/Overhead Switch Replacements (MAT 08S) Is Reasonable

Grasshopper switches are obsolete overhead distribution line switches that PG&E is eliminating from its system. PG&E's Grasshopper/Overhead Switch Replacement Program proactively replaces obsolete switches installed between 1950 and 1970, to minimize potential

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1994 AARP Opening Brief, pp. 30-31; AARP-01, p. 51, lines 3-9.

1995 PG&E-17, p. 13-15, lines 4-6.

1996 PG&E-17, p. 13-15, lines 6-9.

safety issues during switching operations and to improve reliability.[1997] PG&E's capital forecast for Grasshopper/Overhead Switch Replacements (MAT 08S) presented in rebuttal testimony is $0.925 million in 2021, $0.949 million in 2022, $0.975 million in 2023, $1.001 million in 2024, $1.028 million in 2025, and $1.056 million in 2026.[1998] This forecast is subject to escalation as proposed in PG&E's September, 2022 update.

Cal Advocates' recommends $0.3 million for 2023 capital expenditures, nearly a seventy percent reduction of PG&E's forecast, based on reducing PG&E's 2021, 2022 and 2023 replacement levels.[1999] Cal Advocates asserts that PG&E did not explain how PG&E scoped the pace of work for the program.[2000] That is not so. As explained in rebuttal testimony, PG&E's proposed replacement rate of 30 switches per year in its 2023 forecast is consistent with the agreed-upon replacement rate in the 2017 GRC and with the funding authorized in the 2020 GRC, both proceedings in which Cal Advocates was a party.[2001]

Cal Advocates' proposed forecast departs from this GRC replacement rate, reducing PG&E's 2021 replacement level to 12 switches and 2022-2023 replacement level to 9 switches per year. Cal Advocates' proposed forecast is less than one-third of what PG&E forecasted and will not provide sufficient funding for this program. As discussed above, Cal Advocates misunderstands that while it was reasonable to defer certain switch replacements during the 2019-2021 timeframe due to various higher priorities, keeping obsolete equipment on PG&E's

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1997 PG&E-04, p. 13-31, lines 15-22.

1998 PG&E-17, p. 13-28, Table 13-4, line 2 (PG&E recorded and forecast costs).

1999 Cal Advocates Opening Brief, p. 225; CALPA-06, p. 53, lines 13-18.

2000 Cal Advocates Opening Brief, p. 225.

2001 PG&E-17, p 13-16, line 30 to p. 13-17, line 1; *see also* A.15-09-001, Joint Motion for Adoption of Settlement Agreement (Aug. 13, 2016), Appendix C, GRC Settlement Agreement (as ratified by D.17-05-013), p. 15, Section 3.1.3.4; A.18-12-009, Settlement Agreement adopted in the final GRC decision, D.20-12-005, pp. 12-13, Section 2.3.6.5.

system should be avoided. Therefore, PG&E's plan to increase the replacement rate beyond 2019-2021 levels is reasonable.

In addition, Cal Advocates' recommended replacement levels are arbitrary. For example, Cal Advocates does not dispute the safety and reliability risks identified by PG&E. Nor does Cal Advocates suggest that PG&E does not have the capacity to complete the work at the level in PG&E's forecast. Without a valid basis to do so, the proposed reduction is not warranted.

PG&E's GRC forecast of approximately $1 million per year to replace 30 switches per year from 2023 to 2026 is reasonable and should be adopted.

4.13.5 PG&E's Capital Forecast For Distribution Circuit Zone Reliability (MWC 49) Is Reasonable

Work in Distribution Circuit Zone Reliability (MWC 49) focuses on achieving reliability improvements through various targeted reliability measures, including: (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.[2002] PG&E's capital forecast for Distribution Circuit Zone Reliability (MWC 49) presented in rebuttal testimony is $21.455 million in 2021, $26.722 million in 2022, $29.110 million in 2023, $28.974 million in 2024, $29.578 million in 2025, and $32.245 million in 2026.[2003] This forecast is subject to escalation as proposed in PG&E's September, 2022 update.

Cal Advocates recommends forecast reductions for one program within PG&E's capital forecast for MWC 49: Overhead Fuses (MAT49C). PG&E responds to Cal Advocates' specific contentions below.

2002 PG&E-04, p. 13-44, lines 2-10.

2003 PG&E-17, p. 13-5, Table 13-1, lines 8-14; p. 13-28, Table 13-4, lines 8-14; p. 13-29, Table 13-5, lines 8-14.

4.13.5.1 PG&E's Capital Forecast For Overhead Fuses (MAT 49C) Is Reasonable

The work in MAT 49C consists of installing new line fuses on overhead distribution circuits in order to limit the impact and scope of outages and limit the number of customers affected.[2004] PG&E plans to install approximately 100 new sets of overhead fuses per year on tap lines to prevent mainline outages.[2005]

PG&E's capital forecast for Overhead Fuses (MAT 49C) presented in rebuttal testimony is $0.882 million in 2021, $1.519 million in 2022, $1.560 million in 2023, $1.422 million in 2024, $1.497 million in 2025, and $2.967 million in 2026.[2006] This forecast are subject to escalation as proposed in PG&E's September, 2022 update. Cal Advocates recommends reducing PG&E's 2022-2023 pace of work from 129 to 13 installations per year, the approximate average pace of work from 2019-2021, to derive a forecast of $0.3 million.[2007] Cal Advocates proposed reduction is unwarranted.

As PG&E explained in rebuttal testimony, replacement of overhead fuses is a cost-effective targeted reliability program.[2008] Cal Advocates does not provide any justification for reducing PG&E's forecast. Indeed, Cal Advocates does not dispute that the work is necessary. Nor does it dispute that PG&E's unit cost forecast is reasonable. Further, 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 the year. PG&E successfully installed 97 fuses in 2021 as reported in PG&E's Risk Spend Accountability Report.[2009] PG&E plans to

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2004 PG&E-04, p. 13-47, line 28 to p. 13-48, line 2.

2005 PG&E-17, p. 13-26, lines 6-8.

2006 PG&E-17, p. 13-28, Table 13-4, line 14 (PG&E recorded and forecast costs); p. 13-29, Table 13-5, line 11; p. 13-5.

2007 Cal Advocates Opening Brief, p. 227; CALPA-06, p. 55, lines 2-5.

2008 PG&E-17, p. 13-26, lines 20-21.

2009 A.18-12-009, PG&E's RSAR (Mar. 31, 2022), p. 3-20, Table 3-4, line 116.

increase this pace going forward during the GRC period.[2010] PG&E acknowledges that the lower 2018-2020 pace of work was primarily driven by our focus on wildfire mitigation efforts.[2011] However, as demonstrated by the 2021 pace, PG&E has since renewed its efforts to utilize MAT 49C work to improve reliability. The 2023 GRC forecast for MAT 49C reflects PG&E's return to a pace of work similar to its 2016-2017 unit completion rate – which is achievable as demonstrated by PG&E's 2021 actual pace of work.[2012] Accordingly, the Commission should approve PG&E's forecast for MAT 49C.

4.13.6 PG&E's Capital Forecast For Electric Distribution Underground Asset Replacement (MWC 56) Is Reasonable

PG&E's electric underground distribution system consists of primary distribution cable and associated switches, vaults, enclosures, conduits, splices, cable connectors, and other equipment. Capital work in the UAM program primarily consists of replacing underground cables and switches.[2013] PG&E's capital forecast for Electric Distribution Underground Asset Replacement (MWC 56) presented in rebuttal testimony is \$90.160 million in 2021, \$85.382 million in 2022, \$91.317 million in 2023, \$93.066 million in 2024, \$94.845 million in 2025, and \$96.660 million in 2026.[2014] This forecast are subject to escalation as proposed in PG&E's September, 2022 update.

Cal Advocates recommends forecast reductions for four programs within MWC 56: (1) Reliability Related Cable Replacement (MAT 56A); (2) Critical Operating Equipment Cable Replacement (MAT 56C); (3) Load Break Oil Rotary Switch Replacements (MAT 56S); and (4) Temperature Alarm Devices (MAT 56T).

2010 PG&E-17, p. 13-27, lines 1-2.

2011 PG&E-17, p. 13-27, lines 2-4.

2012 PG&E-17, p. 13-27, lines 5-8.

2013 PG&E-04, p. 13-34, line 1 to p. 13-41, line 7.

2014 PG&E-17, p. 13-5, Table 13-1, lines 3-7; p. 13-28, Table 13-4, lines 3-7; p. 13-29, Table 13-5, lines 3-7.

PG&E addresses Cal Advocates' specific contentions below.

4.13.6.1 PG&E's Capital Forecast For Reliability Related Cable Replacement (MAT 56A) Is Reasonable

Reliability Related Cable Replacement (MAT 56A) includes PG&E's forecast for proactively replacing underground distribution cable based on reliability performance, age, and type (i.e., PILC, HMWPE, and XLPE cables), or a combination of these factors and other influences. Replacement candidates are primarily identified in areas (protective zones) experiencing two or more cable failures within five years. PG&E's capital forecast for Reliability Related Cable Replacement (MAT 56A) presented in rebuttal testimony is $38.013 million in 2021, $39.556 million in 2022, $36.976 million in 2023, $37.616 million in 2024, $38.266 million in 2025, and $38.927 million in 2026.[2015] This forecast is subject to escalation as proposed in PG&E's September, 2022 update.

Cal Advocates recommends a forecast of $28.3 million for 2023 capital expenditures, utilizing PG&E's 2018-2020 pace of work to derive a lower forecast, as opposed to PG&E's planned replacement rate.[2016] Cal Advocates argues that the higher pace of work forecast by PG&E is not necessary, and that if the work was high priority, PG&E should not have deferred work from prior years.[2017] Cal Advocates is wrong – the work is necessary and should be funded.

As a threshold matter, Cal Advocates seems to misunderstand what work deferrals mean. It should not be construed as meaning the work is not necessary once the reason for the deferral no longer exists. PG&E deferred certain work that could be reasonably deferred at that time in favor of other higher-priority work within MWC 56.[2018] However, further deferral of the

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2015 PG&E-17, p. 13-5, Table 13-1, lines 3-7; p. 13-28, Table 13-4, lines 3-7; p. 13-29, Table 13-5, lines 3-7.

2016 Cal Advocates Opening Brief, p. 228; CALPA-06, p. 56, lines 15-21.

2017 CALPA-06, p. 56, lines 9-12.

2018 PG&E-17, p. 13-19, line 31 to p. 13-20, line 1.

replacement of failing and aging assets is not prudent and would have reliability and safety consequences.

In addition, the Commission should again reject Cal Advocates' pace-of-work argument because it is counter to current circumstances and PG&E's work plans for maintaining a reliable system. PG&E's forecast 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 that was rescheduled due to construction and estimating (design) resource constraints.[2019] PG&E's experience since this time has allowed for better forecasting (including resource planning) to accommodate the planned scope of work.[2020] PG&E therefore anticipates that it will not have these same resource constraints during the forecast GRC period.

4.13.6.2 PG&E's Capital Forecast For COE Cable Replacement (MAT 56C) Is Reasonable

MAT 56C is a program that replaces single segments of failed cable as opposed to the MAT 56A program that typically replaces much larger segments of cable over several city blocks.[2021] PG&E's capital forecast for COE Cable Replacement (MAT 56C) presented in rebuttal testimony is $34.260 million in 2021, $33.030 million in 2022, $36.002 million in 2023, $36.625 million in 2024, $37.258 million in 2025, and $37.901 million in 2026. This forecast is subject to escalation as proposed in PG&E's September, 2022 update.

Cal Advocates recommends a $24.6 million forecast for 2023 capital expenditures, a downward adjustment of $11.4 million, based on reducing PG&E's 2023 GRC forecast pace of work to PG&E's average pace of work from 2019-2021.[2022] The Commission should reject this

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2019 PG&E-17, p. 13-19, lines 17-21.

2020 PG&E-17, p. 13-19, lines 24-25.

2021 When failures of underground cables occur and the nature of the failure requires immediate replacement or repair, that work is charged to MWC 17 – Routine Emergency Capital or BH – Routine Emergency Expense.

2022 Cal Advocates Opening Brief, p. 229; CALPA-06, p. 58, lines 9-15.

pace-of-work recommendation for the same reasons as its other pace-of-work recommendations discussed above.

The lower pace of work executed in 2019-2020 was caused by construction and estimating (design) resource constraints.[2023] Cal Advocates' concern that PG&E will not be able to increase the pace of work due to continued resource constraints similar to those experienced in 2019-2020 is unwarranted because those particular past constraints have been addressed. As PG&E has become more experienced at resourcing both wildfire mitigation work and base work, PG&E has adjusted its resource plans accordingly, which is reflected in PG&E's forecast.[2024] For example, PG&E has proposed to bolster its estimating resources, which will facilitate PG&E's capacity to complete the work.[2025] Notably, Cal Advocates does not dispute the need for the work to be completed. The Commission should adopt PG&E's 2023 GRC forecast for cable replacement under MAT 56C.

4.13.6.3 PG&E's Capital Forecast For LBOR Switch Replacement (MAT 56S) Is Reasonable

The MAT 56S program targets the removal of antiquated LBOR switches, which are manually operated, oil-filled underground switches that use solid blade mechanisms immersed in oil to break or make loads.[2026] LBOR switches pose a safety risk for crews, as they may fail when operating.[2027] PG&E is working to replace these antiquated switches with devices that conform to current design standards.[2028] PG&E's capital forecast for LBOR Switch Replacement MAT 56S presented in rebuttal testimony is $9.252 million in 2021, $9.493 million in 2022, $8.124 million in 2023, $8.344 million in 2024, $8.569 million in 2025,

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2023 PG&E-17, p. 13-20, lines 22-25.

2024 PG&E-17, p. 13-20, line 28 to p. 13-21, line 4.

2025 PG&E-17, p. 13-21, lines 4-6.

2026 PG&E-04, p. 13-39, lines 27-29.

2027 PG&E-17, p. 13-21, lines 21-22.

2028 PG&E-17, p. 13-21, lines 23-24.

and $8.800 million in 2026. This forecast is subject to escalation as proposed in PG&E's September, 2022 update.

Cal Advocates recommends using a five-year average unit cost to derive a forecast of $2.4 million for 2023 capital expenditures, a two-thirds decrease from PG&E's forecast.[2029] Cal Advocates argues that PG&E only should target LBOR switches without oil inspection sight glasses, and that a two-thirds forecast reduction is justified because only about one-third of PG&E's pre-1975 LBOR switches lack oil-inspection glasses and need to be replaced (with the remaining two-thirds not requiring replacement).[2030] Cal Advocates misunderstands the reasons why PG&E is replacing the switches – 100 percent of the switches must be replaced for public- and employee-safety reasons. For this reason, PG&E's MAT 56S program targets the removal of *all* antiquated pre-1975 LBOR switches.[2031]

Cal Advocates confuses the purpose and significance of the sight glass. The presence of a sight glass only allows workers to determine whether there is oil in the switch; but it does not provide information about the dielectric-insulating quality of that oil.[2032] PG&E must replace all switches, because as they age through normal operation, increasing carbonization in the oil makes it more likely for the oil to break down and the switch to fail.[2033] The sight glass allows a measure of safety for crews operating a switch, but it is not determinative in the prioritization of replacement of pre-1975 LBOR switches.[2034] That is, pre-1975 LBOR switches with sight glasses are not prioritized over replacement pre-1975 LBOR switches without sight glasses – all

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2029 Cal Advocates Opening Brief, p. 231; CALPA-06, p. 60, lines 4-17.

2030 Cal Advocates Opening Brief, p. 231; CALPA-06, p. 60, lines 8-13.

2031 PG&E-17, PG&E's response to Data Request TURN_024-Q04(c), dated 10/5/21, pp. App A-184 to App A-185.

2032 PG&E-17, p. 13-22, lines 10-12.

2033 PG&E-17, p. 13-22, lines 12-15.

2034 PG&E-17, p. 13-22, lines 15-18.

pre-1975 LBOR switches must be replaced.[2035] Statements from the CPUC's Safety and Enforcement Division (previously known as the Office of the Safety Advocates (OSA)) support this plan, recommending that the Commission require PG&E to significantly accelerate the replacement of pre-1975 switches.[2036]

The Commission should reject Cal Advocates proposed two-thirds reduction and approve PG&E's forecast for MAT 56S so that PG&E can replace all pre-1975 LBOR switches.

4.13.6.4 PG&E's Capital Forecast For Temperature Alarm Devices (MAT 56T) Is Reasonable

The Temperature Alarm Devices (TAD) program (MAT 56T) involves installation of temperature monitors on targeted oil-filled subsurface equipment.[2037] The program will allow PG&E to transition to a data-informed asset replacement strategy to prevent catastrophic equipment failures.[2038] PG&E's capital forecast for the TAD program in MAT 56S presented in rebuttal testimony is $9.589 million in 2021, $3.303 million in 2022, $9.099 million in 2023, $9.345 million in 2024, $9.597 million in 2025, and $9.856 million in 2026.[2039] This forecast is subject to escalation as proposed in PG&E's September, 2022 update.

Cal Advocates recommends a forecast of $8.5 million for 2023 capital expenditures using the 2019-2020 average costs.[2040] Cal Advocates reasons that PG&E should no longer experience startup costs incurred in 2018, and therefore removes 2018 costs from the average.[2041] The Commission should reject Cal Advocates' averaging proposal.

2035 PG&E-17, p. 13-22, lines 6-10.

2036 A.18-12-009, HE-275: Exhibit (OSA-01), p. 2-1, line 25 to p. 2-2, line 7.

2037 PG&E-04, p. 13-41, lines 9-11.

2038 PG&E-04, p. 13-41, lines 25-27.

2039 PG&E-17, p. 13-28, Table 13-4, line 10 (PG&E recorded and forecast costs).

2040 Cal Advocates Opening Brief, p. 232; CALPA-06, p. 62, lines 2-9.

2041 Cal Advocates Opening Brief, p. 233; CALPA-06, p. 62, lines 4-6.

Because the program is still relatively new, PG&E is still incurring start-up-related costs similar to those incurred in 2018.[2042] For example, PG&E 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 (DCC).[2043] For this reason, Cal Advocates' recommendation to remove 2018 costs from the averaging methodology will cause the program to be underfunded. This underfunding also will be exacerbated, as PG&E expects material costs to increase compared to previous years.[2044] Accordingly, the unit cost for 2021 to 2026 should be based on a normalized 3-year average from 2018 to 2020, escalated for 2021 through 2026 as PG&E proposes. The Commission should approve PG&E's forecast for MAT 56T in full.

4.14 Network Asset Management

PG&E's distribution networks serve a broad spectrum of commercial and residential customers in the high--density areas of downtown San Francisco and downtown Oakland.[2045] The network systems are designed to maintain service to customers without any outages in the event of an asset failure.[2046]

In its Opening Brief, AARP reiterates the unacceptable contention from their testimony that "there is absolutely no justification for pre-emptive replacement of network assets of any kind" due to the redundancy in the grid design.[2047] Notwithstanding the importance of maintaining safe and reliable electric service to customers, AARP recommends reducing

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2042 PG&E-17, p. 13-25, lines 5-6.

2043 PG&E-17, p. 13-25, lines 6-10.

2044 PG&E-17, p. 13-25, lines 11-13.

2045 PG&E-04, p. 14-1, lines 10-11.

2046 PG&E-04, p. 14-1, lines 10-17; PG&E-17, p. 14-8, lines 13-17.

2047 AARP Opening Brief, p. 33; AARP-01, p. 44, line 13 to p. 45, line 2.

PG&E's 2023-2026 capital forecast for network/underground asset replacement programs by a combined $72.5 million (more than one-third).

In making this recommendation, AARP appears to embrace a run-to-failure operations strategy that largely ignores safety and reliability issues, including for customers, public, and PG&E workers. This approach to maintaining utility assets creates safety risks, ignores the importance of maintaining reliability, and is wholly unsound.

In Section 4.14.1, PG&E summarizes the reasons why its network asset management programs are reasonable. These reasons include: (1) PG&E only replaces assets as necessary to address deteriorated, difficult-to-repair, and obsolete equipment; and (2) PG&E's network asset management activities are critical to maintaining safety and reliability. In Sections 4.14.2 to 4.14.5, PG&E addresses AARP's specific contentions regarding the four specific programs they recommend defunding: (1) Network Transformer (MAT 2CC); (2) Protector Replacement (MAT 2CC); Supervisory Control and Data Acquisition (SCADA) Monitoring equipment upgrades (MAT 2CE); and (4) Primary Network Cable Replacement Program (MAT 56N).

4.14.1 PG&E's Network Asset Management Program Is A Targeted Condition-Based Program Necessary To Ensure Safety And Reliability

There are numerous problems with AARP's recommendation in this proceeding.

First, in testimony and its Opening Brief, AARP characterizes PG&E's replacement programs as though PG&E replaces assets without any regard to the operational condition of the asset and whether it needs to be replaced.[2048] This is incorrect. PG&E's network asset management program includes, among other things, monitoring the condition of network assets through several measures, such as inspections, service records, testing, analysis, and on-line sensor monitoring.[2049] PG&E further considers relevant factors such as expected service life,

2048 AARP-01, p. 48, lines 5-10 (AARP defining what it refers to as pre-emptive replacement) and p. 49, lines 15-16 (AARP asserting that PG&E extensively utilizes pre-emptive replacement strategies).

2049 PG&E-04, p. 14-14, lines 13-15; p. 14-15, lines 11-14 and 22-26.

repairability, and obsolescence.[2050] In short, PG&E's program is a condition-based program, which means that PG&E replaces assets based upon PG&E's engineers' and operators' informed assessment of the suitability of the asset to remain in service or be replaced.

Second, AARP's recommendations for defunding various asset management activities would undermine the safety and reliability benefits arising from this proactive replacement program. This approach to customers' interests in safe and reliable service in their homes and businesses is unacceptable (and inconsistent with AARP's apparent charter). AARP claims to represent the issues that "matter most to families."[2051] Safe and reliable electric service must be one of them, but AARP appears to ignore that. The network systems AARP recommends defunding are located in high-density areas of downtown San Francisco and Oakland. Even a brief outage can result in significant negative impacts to thousands of residential and commercial customers, significant loss of customer business revenues, and potential disruption to medical services and various governmental functions such as public transportation. The failure of electric distribution network assets may also result in public or employee safety issues, property damage, and/or environmental damage.[2052] While redundancy provides reliability to network customers, it also results in higher fault duties (i.e., unintended, uncontrolled, high current flow through an electrical system).[2053] In the event of an asset failure, these high fault duties can result in catastrophic failures such as manhole explosions/fire and pose safety risks to employees and the public.[2054] Given the magnitude of the impacts if an asset failure occurs, it is important for

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2050 PG&E-04, p. 14-15, lines 3-4 (noting units at the end of the useful lives); lines 13-14 (noting the difficulty of items to repair due to obsolescence).

2051 AARP Opening Brief, p. 1.

2052 PG&E-04, p. 14-8, lines 3-7.

2053 PG&E-17, p. 14-9, lines 7-9.

2054 PG&E-17, p. 14-9, lines 9-12.

PG&E to maintain the safety and reliability of the network systems through proactive asset management activities.

Third, AARP's approach essentially appears to argue that PG&E should cease replacement activities until safety and reliability problems occur. For example, AARP observes that of the "60 network equipment failures PG&E reports from 2016 through 2020, not a single customer outage resulted,"[2055] then uses this positive record to argue that PG&E's asset management activities are unnecessary. This run-to-failure and wait-until-problems-occur strategy is an irresponsible way to operate an electric system. In addition, while PG&E's 2016-2020 zero-network-outage record reveals that PG&E has maintained reliability through its proactive network asset management activities, what the record does not show is the number of aging (deteriorating and obsolete) assets in PG&E's network systems requiring replacement. For example, many existing network primary and secondary cables date from the 1920s to the 1960s and are reaching the end of their service life;[2056] PG&E also has identified 22 older dry type transformers in high-rise -buildings, mostly installed in the 1980s, that are at the end of their useful lives;[2057] and there are network protectors still in service dating back to the 1940s through the 1970s with manufacturer rated service lives of approximately 35 years.[2058] These obsolete assets should be replaced so that the zero-outage record continues, not run to failure so that reliability problems emerge as AARP would appear to recommend.

Fourth, AARP incorrectly suggests that many of the assets PG&E plans to replace rarely fail and would not cause outages or safety issues even if they did fail.[2059] AARP does not understand, however, that although one asset failure may not cause an outage, two simultaneous

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2055 AARP Opening Brief, p. 33; AARP-01, p. 45, lines 4-5.

2056 PG&E-04, p. 14-20, lines 15-17.

2057 PG&E-04, WP 14-33.

2058 PG&E-04, WP 14-33.

2059 AARP Opening Brief, p. 34.

asset failures or an asset failure combined with an existing maintenance asset-outage could lead to potentially catastrophic consequences.[2060] In the event of such failures, the remaining energized assets will experience significant increased load that when extended for a long period of time (i.e., longer than 24 hours), [2061] could lead to catastrophic failures.[2062] AARP is also mis-informed that asset failures do not pose safety risks; indeed, as noted above, the failure of even one asset can cause electric current spikes that result in catastrophic failures such as manhole explosions/fire that pose safety risks to employees and the public.[2063] PG&E's asset management plan is designed to prevent these potentially catastrophic events from occurring. It is also designed to allow for regularly-scheduled inspection and maintenance asset outages.

Fifth, AARP's run-to-failure approach fails to account for the fact that network asset repair activities generally take much longer compared to replacement activities on a radial underground system.[2064] Due to the location of network assets (underground and in high-rise- buildings in a congested downtown environment), repairs usually require coordination with customers, clearances, permitting (with local agencies and transit agencies), and specialized resources to perform repairs.[2065] Indeed, repairs to several network assets could take weeks or months to complete, while leaving customers vulnerable to additional asset failures, which could possibly result in prolonged outages.[2066] Due to the length of these repairs, it is prudent for PG&E to coordinate its asset replacement work on a planned basis and schedule, as opposed to addressing repair or replacement issues on an emergent basis as suggested by AARP.

2060 PG&E-17, p. 14-8, lines 1-9.

2061 PG&E-17, p. 14-9, lines 3-5.

2062 PG&E-17, p. 14-9, lines 5-7.

2063 PG&E-17, p. 14-9, lines 9-12.

2064 PG&E-17, p. 14-10, lines 5-6.

2065 PG&E-17, p. 14-10, lines 6-9.

2066 PG&E-17, p. 14-10, lines 9-12.

For all these reasons, the Commission should reject the run-to-failure principles advocated by AARP. PG&E addresses below the specific activities that AARP recommends defunding.

4.14.2 PG&E's Forecast For Network Component Replacements – High-Rise Dry-Type Transformers (MAT 2CC) Should Be Adopted In Full

AARP recommends zero funding for replacing dry-type transformers, arguing that the replacements are unnecessary from a safety perspective.[2067] In support, AARP asserts that "despite tens of thousands of transformers located in high--rise buildings across the U.S., AARP experts are not aware of any incidents where one caused a fire, let alone any such incidents involving a dry--type transformer."[2068] AARP further argues that PG&E's low RSE for the program demonstrates the low safety risk.[2069] In focusing primarily on safety-issues, AARP misses the point of these particular transformer replacement activities. As PG&E explained in rebuttal testimony, the principal driver for this work is reliability, not safety. The dry-type transformers planned for replacement are older dry---type transformers that are at the end of their useful lives.[2070] The replacement transformers are either explosion resistant or dry-type and use a single tank design to minimize the risk of catastrophic failure.[2071] The RSE for the program is low because the program primarily addresses reliability, not safety.[2072]

Further, many, if not all, of these older dry-type transformers are custom-made and PG&E does not stock any spare units.[2073] A replacement unit takes six to eight months to

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2067 AARP Opening Brief, p. 34; AARP-01, p. 46, lines 10-11; p. 53, Table, line "Network Capital (PG&E-04, 14-12)."

2068 AARP-01, p. 46, lines 2-8.

2069 AARP-01, p. 46, lines 8-11.

2070 PG&E-17, p. 14-12, lines 9-11.

2071 PG&E-04, p. 14-14, line 30 to p. 14-15, line 7.

2072 PG&E-17, p. 14-12, lines 14-16.

2073 PG&E-17, p. 14-12, lines 22-23.

acquire under normal supply chain conditions.[2074] Without funding for this program, PG&E would not be able to plan proactive replacements of older dry-type transformers, putting customers at risk of a prolonged months-long outage in the event of a transformer failure.

4.14.3 PG&E's Forecast For Network Component Replacements – Targeted Network Protector Replacement Should Be Adopted In Full

AARP recommends zero funding for Network Component Replacements – Targeted Network Protector Replacement (MAT 2CC).[2075] Again, AARP contends there is no justification for pre-emptive replacement of network assets of any kind, and that if a network protector fails, it can be replaced with no interruption in service to customers.[2076] As discussed above, identifying and replacing deteriorated, damaged, or obsolete equipment proactively is fundamental to maintaining system reliability. For this activity, PG&E plans to replace all CMD network protectors, which are difficult to repair and contain obsolete components,[2077] with more reliable network protector models.[2078] Proactive replacement of the CMD network protectors therefore eliminates obsolete components and will help maintain system reliability.

4.14.4 PG&E's Capital Forecast For Network SCADA Safety Monitoring (MAT 2CE) Is Reasonable

AARP further proposes that the Commission authorize zero funding for PG&E's planned installation of Supervisory Control and Data Acquisition (SCADA) equipment upgrades.[2079] Questioning the safety and reliability benefits of the upgrade program, AARP contends that upgrades are not necessary. AARP is again wrong.

2074 PG&E-17, p. 14-12, lines 23-24.

2075 AARP Opening Brief, pp. 7, 32-34; AARP-01, p. 45, lines 1-2; p. 53, Table, line "Network Capital (PG&E-04, 14-12)."

2076 AARP-01, p. 45, lines 1-4.

2077 PG&E-17, p. 14-13, lines 14-17.

2078 PG&E-04, p. 14-15, lines 11-16.

2079 AARP Opening Brief, pp. 33-34.

PG&E's existing network SCADA systems were installed in the 1980s and are past their projected life expectancy. Indeed, these older systems are based on obsolete technology and significantly limited, only measuring load and open/close status of the network protectors.[2080] The new upgraded SCADA systems are designed to improve safety on the distribution networks. They also will monitor additional conditions including oil temperature, oil level, and tank pressure to identify issues in a specific transformer.[2081] In addition, the new systems have control capabilities allowing Distribution Operators to remove a unit from service remotely if a system identifies a problem on the transformer or protector.[2082] Information from the systems is used for real time safety assessment and is part of the condition-based- maintenance and replacement process now used for the distribution network systems.[2083]

AARP's reasoning assumes that safety improvements are impossible when there are no recorded safety incidents associated with the existing SCADA system. This reasoning is nonsensical. The proposed SCADA monitoring upgrades would replace obsolete technology and provide additional functionality, both of which will enhance safety. Further, the SCADA upgrades will enable remote operation, which reduces the instances of PG&E employees working in dangerous conditions when opening or closing network protectors.[2084] AARP's reasoning is also counter to prudent utility practices to reasonably incorporate safety improvements even in the absence of documented safety incidents.

2080 PG&E-17, p. 14-15, lines 2-4.

2081 PG&E-17, p. 14-15, lines 6-8.

2082 PG&E-17, p. 14-15, lines 8-11.

2083 PG&E-04, WP 14-24.

2084 PG&E-17, p. 14-16, lines 1-3.

AARP's objection to SCADA monitoring upgrades is perplexing, given AARP's position that utilities should use objective criteria to determine which assets require replacement.[2085] The upgraded SCADA system will facilitate identifying failing assets with objective criteria.

In sum, AARP's SCADA-defunding recommendation is unreasonable. Disallowing the forecasts would leave the existing 1980s era SCADA systems, which do not provide the information necessary for condition-based maintenance and replacement, in place. This system is critical to reduce in-service failures for safe and reliable operations. The Commission should approve PG&E's requested funding for the program.

4.14.5 PG&E's Capital Forecast For Primary Network Cable Replacement Program (MAT 56N) Is Reasonable

The Primary Network Cable Replacement program involves the systematic replacement of network cable assets.[2086] AARP recommends that the Commission authorize zero funding for this program. Similar to its other contentions, AARP continues to claim there is no justification for pre-emptive replacement of any network assets.[2087] AARP is again wrong.

Primary and secondary network cable failures pose both safety risks. Failures can result in electrical outages, equipment damage, explosions, smoke and fires; some of which may cause personal injury and property damage.[2088] These risks are more consequential with network cables since network cables are located in dense urban environments with significant pedestrian traffic. Since 2008, there have been a total of 145 network cable and splice failures in San Francisco and Oakland.[2089] As these facilities age, PG&E anticipates continued cable and splice failures.[2090] Some of these failures were catastrophic failures which, while rare, resulted

2085 AARP-01, p. 47, line 5 to p. 48 line 2.

2086 PG&E-04, p. 14-20, lines 4-5.

2087 AARP-01, p. 45, lines 1-3.

2088 PG&E-17, p. 14-17, lines 11-14.

2089 PG&E-17, p. 14-17, lines 17-18.

2090 PG&E-04, WP 14-28.

in fires, manhole displacements, and/or vault explosions with significant public safety consequences.[2091] Many of the existing network primary and secondary cables date from the 1920s to the 1960s and are reaching the end of their service life.[2092] This program will expedite the completion of primary cable replacements on the network system.[2093] Without funding for this 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.

4.15 Substation Asset Management

Cal Advocates, TURN, and AARP recommend forecast reductions to PG&E's Substation Asset Management programs.[2094] The disputed programs are tracked in three MWCs: Electric Distribution Substation, Replace Other Equipment (MWC 48); Electric Distribution Substation, Replace Transformers (MWC 54); and Electric Distribution Substation, Safety and Security (MWC 58). PG&E will discuss the parties' recommendations below

4.15.1 PG&E Has Already Fully Addressed Cal Advocates' Arguments.

Cal Advocates recommends forecast reductions to six MATs in MWC 48: Circuit Breaker Replacement (MAT 48D); Animal Abatement (MAT 48X); Battery Replacement (MAT 48C); Switch Replacement (MAT 48E); Civil Structures (MAT 48H); and Insulator Replacement (MAT 48N).[2095] Cal Advocates also recommends forecast reductions to one MAT in MWC 54 – Transformer Replacement (MAT 54A) – and two MATs in MWC 58 – Fire Suppression and Safety (MAT 58A) and Distribution Substation and Security (MAT 58S).[2096] For 2023, Cal Advocates proposes: (1) $27.6 million in reductions to PG&E's overall MWC 48 forecast of

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2091 PG&E-04, p. 14-5, lines 33 to p. 14-6, line 2.

2092 PG&E-04, p. 14-20, lines 15-17.

2093 PG&E-04, p. 14-20, lines 15-31.

2094 Cal Advocates Opening Brief, p. 234; TURN Amended Opening Brief, pp. 465-466; AARP Opening Brief, pp. 37-38.

2095 PG&E Opening Brief, pp. 535-536 (MAT 48D); pp. 541-543 (other MATs).

2096 PG&E Opening Brief, pp. 545-548.

$96.3 million;[2097] (2) $0.2 million in reductions to PG&E's overall MWC 54 forecast of $21.2 million;[2098] and (3) $3.1 million in reductions to PG&E's overall MWC 58 forecast of $8.2 million.[2099] Cal Advocates also recommends a $1.5 million disallowance to PG&E 2020 recorded costs for Switchgear Maintenance (MAT 48F).[2100]

The discussion of these recommendations in Cal Advocates' Opening Brief restates almost verbatim the prepared testimony that Cal Advocates submitted.[2101] Cal Advocates' Opening Brief does not refute, or even mention, PG&E's rebuttal testimony. PG&E's rebuttal testimony and Opening Brief thoroughly address the arguments in Cal Advocates' prepared testimony.[2102]

4.15.2 TURN's Recommendations Should Not Be Adopted

TURN recommends a forecast reduction to one MAT in MWC 48: Circuit Breaker Replacement (MAT 48D).[2103] For 2023, TURN recommends an $18.6 million reduction to PG&E's MAT 48D forecast of $28.6 million.[2104] TURN argues that PG&E's forecast reflects a significant increase in proactive circuit breaker replacement and should be based instead on historical levels of spending because PG&E has frequently forecast significant increases in proactive circuit breaker replacement routinely and then spent less than its

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2097 PG&E Opening Brief, p. 534, Table 4-42.

2098 PG&E Opening Brief, p. 545, Table 4-43.

2099 PG&E Opening Brief, p. 547, Table 4-44.

2100 PG&E Opening Brief, p. 544.

2101 Compare CALPA-06, p 62, line 19 to p. 82, line 11 with Cal Advocates Opening Brief, pp. 235-250.

2102 PG&E-17, p. 15-7, line 10 to p. 15-24, line 28 (MATs in MWC 48); p. 15-25, line 1 to p. 15-26, line 17 (MAT 54A); p. 15-28, line 9 to p. 15-30, line 14. PG&E Opening Brief, pp. 535-538 (MAT 48D); pp. 541-543 (MATs 48X, 48C, 48E, 48H and 48N); pp. 544-545 (MAT 48F); pp. 545-546 (MAT 54A); and pp. 547-548 (MATs 58A and 58S).

2103 TURN Amended Opening Brief, pp. 465-466.

2104 TURN Amended Opening Brief, p. 466.

authorized forecast.[2105] TURN also argues that PG&E's claim that its failure rate for circuit breakers is increasing is not supported by the data.[2106]

PG&E has demonstrated that its MWC 48D forecast is appropriate, even though it represents a substantial increase over recent historical spending. As explained in PG&E's Opening Brief, PG&E has decided to prioritize proactive circuit breaker replacement in this GRC period because, with a large number of circuit breakers nearing or beyond end-of-life, PG&E expects failures to increase.[2107] In order to facilitate completion of the work, PG&E has reduced its substation spending in other areas such as Switchgear Replacement (MAT 48F) and Transformer Replacement (MAT 54A).[2108] PG&E's rebuttal testimony describes the safety, reliability and cost benefits of proactive replacement of substation equipment relative to just-in-time replacement[2109]; TURN does not discuss or dispute this testimony in its Opening Brief.

TURN recommends in the alternative that PG&E's MWC 48D forecast should be placed in a balancing account.[2110] PG&E addressed this recommendation in its Opening Brief.[2111]

4.15.3 AARP's Recommendations Should Not Be Adopted

AARP recommends zero funding for PG&E's proactive substation replacement programs in MAT 48D (Circuit Breaker Replacement), MAT 48E (Switch Replacement), MAT 48L (Line Work) and MAT 54A (Transformer Replacement). The discussion of these recommendations in AARP's Opening Brief restates almost verbatim the prepared testimony that AARP

2105 TURN Amended Opening Brief, pp. 465-468.

2106 TURN Amended Opening Brief, p. 468.

2107 PG&E Opening Brief, p. 539.

2108 PG&E Opening Brief, p, 536.

2109 PG&E-17, p. 15-10, line 22 to p. 15-11, line 20; *see also* PG&E Opening Brief, pp. 537-538.

2110 TURN Amended Opening Brief, p. 468.

2111 PG&E Opening Brief, p. 539.

submitted.[2112] AARP's Opening Brief does not refute, or even mention, PG&E's rebuttal testimony. PG&E's rebuttal testimony and Opening Brief thoroughly address the arguments in AARP's prepared testimony.[2113]

4.16 Distribution System Automation And Protection (DSAP)

PG&E's expense and capital forecast for DSAP is uncontested.[2114]

4.17 Electric Distribution Capacity, Engineering And Planning

Cal Advocates and TURN recommend forecast reductions for activities in this area.[2115] The disputed programs are tracked in two capital MWCs – work in MWC 06 consists of capacity expansion work outside of substations and work in MWC 46 consists of upgrades to various piece of substation equipment that are forecast to have a capacity deficiency.[2116] PG&E discusses each of the parties' recommendations below

4.17.1 PG&E Has Already Fully Addressed Cal Advocates' Arguments

Cal Advocates proposes two reductions to PG&E's capacity programs: (1) a reduction to PG&E's 2022 forecast for MAT 06H (New Business-Related Capacity Work) due to lower than expected historical spending in 2021, and (2) removal of PG&E's entire capital expenditure forecast for the Garberville capacity project due to uncertainty about the project's schedule.[2117]

2112 Compare AARP-01, p. 47, line 4 to p. 49, line 12 with AARP Opening Brief, pp. 35-37.

2113 PG&E-17, p. 15-13, line 16 to p. 15-15, line 21 (MAT 48D); p. 15-18, line 24 to p. 15-19, line 28 (MAT 48L); p. 15-2, line 27 to p. 23, line 26 (MAT 48E); p. 15-26, line 18 to 15-27, line 27 (MAT 54A); and PG&E Opening Brief, pp. 540-541.

2114 PG&E Opening Brief, p. 549.

2115 Cal Advocates Opening Brief, p. 252; TURN Amended Opening Brief, pp. 469-470.

2116 PG&E Opening Brief, p. 550. Cal Advocates and JCCA also raised non-forecast issues with respect to the Renz Energy Storage project, but those issues have been resolved. PG&E-17, p. 17-16, lines 19-22.

2117 Cal Advocates Opening Brief, pp. 253-258.

For 2023, Cal Advocates' proposes $18.4 million in reductions to PG&E's $195.8 million overall capital forecast for capacity work in MWCs 06 and 46.[2118]

The discussion of these issues in Cal Advocates' Opening Brief restates almost verbatim the prepared testimony that Cal Advocates submitted.[2119] Cal Advocates' Opening Brief does not refute, or even mention, PG&E's rebuttal testimony. PG&E's rebuttal testimony and Opening Brief thoroughly address the arguments in Cal Advocates' prepared testimony.[2120]

4.17.2 TURN's Proposed Reductions To Funding For Capacity Work Related To Agricultural Load Should Not Be Adopted

TURN recommends a $30 million reduction to PG&E's $195.7 million 2023 combined capital forecast for capacity work in MWCs 06 and 46.[2121] TURN estimates that agricultural load growth accounts for approximately $60 million of PG&E's capacity forecast and recommends that PG&E's forecast related to agricultural load should be reduced by 50 percent because of the likely impact of recently implemented Time of Use (TOU) agricultural rates.[2122] PG&E's rebuttal testimony and Opening Brief pointed out three flaws in TURN's arguments.

First, PG&E explained that many of the projects that TURN used to estimate to amount of agricultural load in PG&E's forecast were not part of the forecast. Instead, these projects were emergent projects identified after the creation of the forecast but listed in PG&E's workpapers and some discovery responses to align them with the 2021 Distribution Investment Deferral Framework process and the 2021 Grid Need Assessment and Distribution Deferral Opportunity Reports. The 2023 forecast for the six agricultural and cannabis-related capacity

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2118 PG&E Opening Brief, p. 550, Table 4-45.

2119 Compare CALPA-06, p. 87, line 10 to p. 93, line 1 with Cal Advocates Opening Brief, pp. 253-258.

2120 PG&E-17, p. 17-6, line 3 to p. 17-9, line 4; PG&E Opening Brief, pp. 551-552.

2121 PG&E Opening Brief, p. 550, Table 4-45.

2122 TURN Amended Opening Brief, pp. 469-470.

projects actually included in the forecast is $25.7 million.[2123] Thus, even if the rest of TURN's analysis is correct – which it is not – PG&E's forecast should only be reduced by $12.8 million.

In its Opening Brief, TURN argues that projects that PG&E listed in workpapers and identified at the time when PG&E responded to a TURN discovery request in November 2021 should be considered part of PG&E's forecast.[2124] But, as PG&E explained above, the spending for these projects was never part of PG&E's forecast and the projects were only listed in PG&E's workpapers so that they would align with PG&E's list of projects in other proceedings. Moreover, as PG&E discussed in its rebuttal, TURN incorrectly assumed that several identified projects were driven by agricultural load growth based on the mere fact that they are located in rural areas.[2125]

Second, in its rebuttal testimony and its Opening Brief, PG&E disagreed with TURN's analysis of the anticipated effect of TOU rate changes on agricultural pumping loads and presented evidence that the adoption of TOU rates does not automatically correlate to measurable changes in load.[2126] In its Opening Brief, TURN claims that a CEC-funded study using data from PG&E's service territory found that with "clear price signals and automation," agricultural users shifted significant load to off peak periods.[2127] TURN argues that PG&E should encourage its customers to adopt automation, and that the result will be lower peak load than what PG&E has forecast.[2128]

As a preliminary matter, PG&E notes that increases in agricultural pumping load make up a very small portion of its capacity forecast. More importantly, the CEC study that TURN

2123 PG&E Opening Brief, p. 553; PG&E-17, p. 17-12, line 1 to p. 17-14, line 3.

2124 TURN Amended Opening Brief, pp. 478-479.

2125 PG&E-17, p. 17-12, line 21 to p. 17-13, line 1.

2126 PG&E Opening Brief, p. 553; PG&E-17, p. 17-13, line 9 to p. 17-14, line 3.

2127 TURN Amended Opening Brief, pp. 479-480.

2128 TURN Amended Opening Brief, p. 480.

relies on was a small pilot implemented by Polaris, an irrigation control hardware company, that "built on existing Polaris control hardware and software and expanded it to integrate with energy markets, customer relationship management systems, third-party party platforms and big data visualization and analytics solutions."[2129] Based on a six-month study with three users (a water district, a ranch, and a farm), the Report concluded that "with sufficient automation" customers would shift a significant amount of load to non-peak hours.[2130] However, the report also concluded that "current market mechanisms and automation incentives can entice only a small portion of agricultural [] load shift potential."[2131] The report notes that "with the exception of the pumps participating in this project, [Polaris] automation is only used to stop pumps (not start them) and only in the context of infrequently dispatched DR programs, not for daily operations."[2132] The report continues, "Adoption of these technologies remains low and, prior to this project, there was no comprehensive system that enabled the creation and implementation of pump operation schedules with consideration of time-of-use (TOU) … pricing."[2133] In other words, there are still substantial technical and operational roadblocks to automation. PG&E has not seen significant automation of agricultural pumping operations in its service territory and does not expect there to be significant automation for several years at the earliest. PG&E's forecast is for needs that will arise during this GRC period, which the theoretical possibility of load shifting through automation will not ameliorate.

Third, PG&E provided evidence that TOU rates were not likely to significantly reduce the need for projects to address cannabis load because (1) cannabis cultivation is highly localized

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2129 Meyers et al., Technologies and Strategies for Agricultural Load Management to Meet Decarbonization Goals (updated Oct. 1, 2021) CEC-500-2021-044 (CEC Report), p. 2.

2130 CEC Report, p. 2.

2131 CEC Report, p. 3.

2132 CEC Report, p. 8.

2133 CEC Report, p. 9.

and tends to overwhelm distribution infrastructure regardless of the time of peak, and (2) the main driver for cannabis growers is time to market and they are relatively insensitive to electricity rates.[2134]

TURN argues that PG&E's first argument is irrelevant because the projects at issue here "are driven only by peak load forecasts" and that to the extent "PG&E is arguing that certain load is so high it will exceed the capacities of distribution equipment even during other times of the day, any such deficiencies should be addressed as a matter of course through one of the other programs that address distribution asset capacity."[2135]

PG&E does not agree that projects driven by New Business overloads which occur at times other than peak should be removed from the New Business Capacity forecast in MAT codes 06H and 46H. Projects are assigned to MAT codes based on the source of the overloads, not when they occur or how large they are. A 20 MW data center, for example, would overload an existing circuit with 3 MW available capacity at peak. This overload, due to the magnitude of new load relative to the magnitude of available capacity, is likely to occur at all hours of day and night. Because the project that mitigates the overload is driven by a New Business application, all work is recorded under MAT code 46H and 06H. Also, regardless of whether the deficiency that needs to be addressed is due to peak load or overall load, the cannabis projects that PG&E has forecast are necessary. To remove funding for these projects from PG&E's New Business and Capacity Deficiency forecast on the theory that they should have been (but were not) forecast as part of a different capacity program elevates form over substance and would impede PG&E's ability to address the capacity deficiencies these cannabis projects will create.

TURN responds to PG&E's second argument by stating that it agrees cannabis growers likely care more about plant growth than electricity costs, but this is irrelevant.[2136] TURN

2134 PG&E Opening Brief, p. 554; PG&E-17, p. 17-14, line 4 to p. 17-15, line 19.

2135 TURN Amended Opening Brief, p. 480.

2136 TURN Amended Opening Brief, p. 481.

claims that shifting load will not impact plant growth and that PG&E's actual observed AMI data for greenhouse cultivation in the Salinas Valley and Humboldt County shows that indoor growers appear to be responsive to peak rates.[2137]

PG&E agrees that *non-greenhouse* indoor cultivation (warehouse cultivation) has the ability to shift usage, because indoor cultivation as a process is untethered to natural lighting cycles. However, of the cannabis projects that are included in PG&E's workpapers, new applications for service in the Humboldt, Rio Dell, Garberville, Hollister, Salinas, and Watsonville areas, are all greenhouse cultivation.[2138] In these cases, artificial lighting is only used to extend natural daylight. Natural daylight floods the greenhouse during the middle of the day, making additional lighting unnecessary, but when daylight is dim or not available in the morning and evening hours, additional lighting is used. Because lighting must be continuous and because plants require a period of rest, lighting usage cannot be shifted to the middle of the night.

Although TURN claims that "observed AMI data for greenhouse cultivation in the Salinas Valley and Humboldt County" support its position, the opposite is true. The discovery response TURN relies on – TURN-204, GRC-2023-PhI_DR_TURN_214-Q002 – discusses and presents load shapes for both warehouse cultivation and greenhouse cultivation.[2139] TURN's analysis and conclusions (e.g., that "indoor cultivators [] do not rely on outdoor light") are based on "the normalized annual load profile for 18-hour cannabis <u>indoor</u> cultivation" from "observed AMI meter data for <u>indoor</u> cultivation in the <u>Moss Landing and Oakland areas</u>," not the load

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2137 TURN Amended Opening Brief, p. 481-482.

2138 See PG&E-27-EC, PG&E's response to Data Request TURN_047-Q02Atch01-CONF, dated 11/16/21 (Appendix B, Confidential documents for Exhibit 17). Column N shows the following projects as greenhouse cultivation: Hollister, Spence, Garberville, Gabilan, Green Valley, Chualar, and Rio Dell.

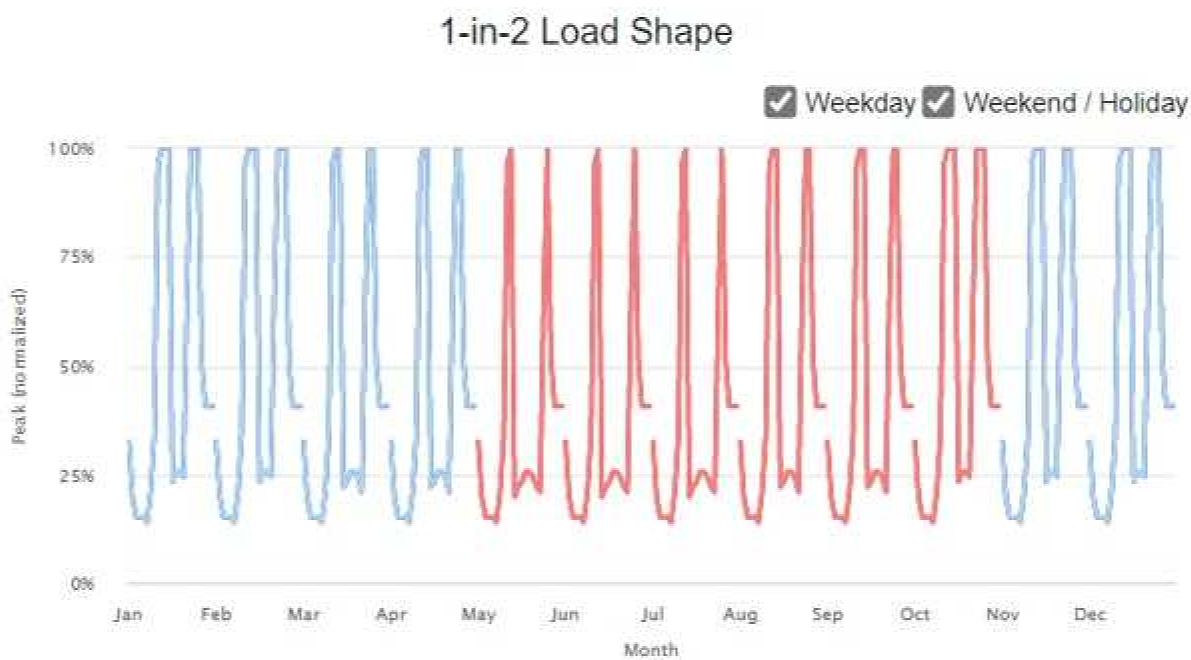
2139 See TURN Amended Opening Brief at 482, fns. 1425 and 1426 (citing TURN-204, PG&E's response to Data Request TURN_214-Q02, dated 6/7/22, pp. 003-005 (which TURN describes as "PG&E Response to DR TURN 214-02").

profile for greenhouse cultivation.[2140] The load profile for greenhouse cultivation based on observed AMI data from the Salinas Valley and Humboldt Count included in GRC-2023-PhI_DR_TURN_214-Q002 (and shown below) tells a completely different story:

> Greenhouse growers use lighting to extend daylight in order to grow plants more rapidly than would occur with natural daylight. Because of this, greenhouse peak usage [occurs] around 9am and again around 7pm during summer and between 8am and 10am and again between 6pm and 8pm in winter.[2141]

FIGURE 4-1:

LOAD PROFILE FOR GREENHOUSE CULTIVATION BASED ON OBSERVED AMI DATA)



Because greenhouse growers use artificial light to supplement natural light at the beginning and end of the day, their time-of-use is constrained. As a result, PG&E does not believe these growers have the flexibility to adjust their usage to fall outside of TOU peak times.

2140 TURN Amended Opening Brief, p. 482 (emphasis added).

2141 TURN-204, PG&E's response to Data Request TURN_214-Q02, dated 6/7/22, p. 004.

Finally, and in some ways most importantly, PG&E has received so many applications for new service since filing its forecast that TURN's recommended forecast reductions would hamstring PG&E even if TURN is correct that agricultural load growth will be less than PG&E has forecast. As PG&E explained in its Opening Brief, PG&E received multiple applications for service for new electric vehicle (EV) fast charging stations after the 2023 GRC was filed.[2142] The six largest of these EV projects will enable 195 megawatts of freeway and highway charging at a total cost to the capacity program of $113 million.[2143] PG&E's emergent capacity forecast in the GRC is already insufficient to cover these projects, and TURN's proposed $30 million dollar reduction to PG&E's forecast would only make the problem worse. PG&E's forecast should be approved so that it has resources to pursue these and other emergent projects.

4.18 New Business And Work At The Request Of Others

Cal Advocates and TURN recommend forecast reductions for activities in this area.[2144] The reductions are to four areas of MWC 16: Residential Connects (Cal Advocates and TURN); Non-Residential Connects (Cal Advocates), Plug-in Electric Vehicles (TURN); and Transformer Purchases (Cal Advocates). PG&E discusses each of the parties' recommendations below:

4.18.1 Cal Advocates' Recommended Adjustments to PG&E's Residential And Non-Residential Connects Forecast Should Not Be Adopted

PG&E forecasts electric New Business residential and non-residential connect expenditures by multiplying the projected volume of work (measured by forecasting new connects to PG&E's distribution system) and the corresponding unit cost. As in the 2017 and 2020 GRCs, the new connects forecast was developed using a proprietary economic model developed by Rosen Consulting Group (RCG), a leading independent real estate economics consulting firm that specializes in California and Bay Area markets. The RCG model analyzes

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2142 PG&E Opening Brief, p. 554.

2143 PG&E Opening Brief, p. 554 (citing PG&E-17, p. 17-15, line 22 to p. 17-16, line 6).

2144 Cal Advocates Opening Brief, p. 261; TURN Amended Opening Brief, pp. 483-484, 488.

PG&E historic New Business connects data in relation to historic leading indicator data using a multiple linear regression technique.[2145]

Cal Advocates criticizes the RCG connects model and developed "adjustment factors' which it applied to PG&E's new connections forecast. Based on these adjustments, for 2023 Cal Advocates recommends a $2.7 million increase to PG&E's forecast for residential connects (from $261.6 million to $264.3 million) and a $45.5 million decrease to PG&E's forecast for non-residential connects (from $192.9 million to $147.4 million).[2146]

As stated in PG&E's Opening Brief, PG&E's rebuttal testimony explains in detail why Cal Advocates approach is not statistically sound. Cal Advocates does not recognize that the results of RCG's connects model do not represent a single model run performed at one time with one set of data but rather combines the results of multiple runs of the connects model performed at different points in time with different data to produce the cited forecasts. Using one forecast year from one model run and appending the next forecast year from a different model run, when different data were available, as Cal Advocates has done, is inappropriate.[2147]

In its Opening Brief, Cal Advocates continues to insist that its adjustment factors are reasonable. Cal Advocates notes that RCG's non-residential connects forecast was higher than recorded in every year from 2015-2020.[2148] While that may be true, that does not mean that Cal Advocates' flawed "adjustment factor" approach is a more reasonable forecasting methodology that RCG's method. In fact, PG&E's recorded non-residential connects in 2021, the most recent year for which PG&E has data, exceeded RCG's connects forecast by nearly 15 percent, which

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2145 PG&E-04, p. 18-25, lines 8-20.

2146 Cal Advocates Opening Brief, p. 261, Table 3 (line items for "Total Residential" and "Non-Residential Connects").

2147 PG&E Opening Brief, p. 557 (citing PG&E-17, p. 18-7, lines 2-15; p. 18-AtchA-4).

2148 Cal Advocates Opening Brief, pp. 262-264.

completely undermines Cal Advocates claim that RCG's model has systematic error that consistently overstates the number of connects.[2149]

Although it claims otherwise, Cal Advocates continues to join multiple forecast vintages together. Cal Advocates' graph comparing RCG's connects forecasts to PG&E recorded connects uses interconnected lines to imply some relationship between multiple forecast vintages.[2150] The importance of separate vintages is not just one of graphical interpretation. Each forecast vintage is prepared using information available at the time. Importantly, each vintage is derived from a living model, that is the model construct is evaluated and calibrated with each iteration based upon new data sources, updated input variables, and PG&E connects data. The fact that each model iteration is a different formula based upon different sets of data is a key consideration missed by Cal Advocates.

Cal Advocates seeks to impose an adjustment factor based upon averages and sums of results from different forecast vintages. This means that there is no "average error" or "ongoing methodological inaccuracy" as cited by Cal Advocates because fundamentally the aggregation of multiple projections spanning 2015 through 2020 is flawed. Cal Advocates' adjustment is based upon an average of projections that come from multiple models. Given that each modeled projection is a distinct projection, Cal Advocates' methodology erroneously averages unrelated projections. Cal Advocates states, "the fact that RCG's forecasts were performed at different times with different data is irrelevant."[2151] However, it is in fact a critical fact and entirely relevant to the modeling process. This highlights Cal Advocates' misunderstanding that each model run is a distinct activity that produces different results.

2149 Compare PG&E-04, WP 18-26, Table 18-26, line 11 (2021 non-residential unit forecast of 7,025) with TURN-307, PG&E's response to Data Request TURN_238-Q02, dated 8/5/22, p. 2, line 11 (2021 recorded non-residential units of 8,001). [8,001/7,025 = 1.14].

2150 Cal Advocates Opening Brief, p. 264, Graph 05-2.

2151 Cal Advocates Opening Brief, p. 268.

Cal Advocates asserts that there is "an ongoing methodological inaccuracy in RCG's model,"[2152] yet does not explain what this methodological inaccuracy is. The RCG reports provide a detailed description of methodology used in each model estimation. RCG followed a rigorous selection method for an econometric model and performed statistical tests and calibrations to ensure there is no bias or model misspecification. Finally, RCG reviewed the residuals after the model estimation to make sure that each model output accounts for all trends and any remaining residuals are random and approach zero. Cal Advocates fails to list any methodological inaccuracy, and simply suggests an adjustment while not providing any methodological reason for their adjustment. There are known industry standards for creating and estimating forecast models. RCG uses industry accepted and recognizable econometric and time series methods, while Cal Advocates does not suggest a viable or statistically relevant alternative method.

In addition, PG&E notes that even if Cal Advocates' "adjustment factor" approach has some merit (which it does not), Cal Advocates use of six years of data vastly overstates the alleged flaws in RCG's model as used for the 2023 GRC forecast. Cal Advocates own chart shows that the difference between RCG's non-residential connects forecast and PG&E's recorded non-residential connects was consistently smaller in 2018-2020 than 2015-2017. In other words, RGC's model has become much accurate over time. And, as explained above, PG&E's 2021 recorded non-residential connects were almost 15 percent higher than RCG's forecast.

PG&E's 2021 recorded unit costs for non-residential connections were also significantly higher (21 percent) than its 2021 forecast unit cost.[2153] PG&E used the same forecast unit cost

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2152 Cal Advocates Opening Brief, p. 265.

2153 Compare PG&E-04, WP 18-26, Table 18-26, line 12 (2021 forecast unit cost of $23,115) with TURN-307, PG&E's response to Data Request TURN_238-Q02, dated 8/5/22 (2021 recorded non-residential unit cost of $28,022). [$28,022/$23,115 = 1.21].

for 2021-2026.[2154] In other words, PG&E's 2021 recorded unit costs were already significantly higher than its forecast for this GRC period. This suggests that even if PG&E experiences fewer connections than forecast, its overall forecast would still be appropriate because it is also likely to experience higher than forecast unit costs.

4.18.2 TURN's Recommended Reduction to PG&E's Residential Connections Forecast Should Not Be Adopted

TURN recommends a $53.9 million reduction to PG&E's 2023 forecast of $261.6 million for residential connections.[2155] One of the variables used in the RCG connects model is residential permits, and TURN believes that RCG's forecast for residential permits is overly optimistic because it (and by extension PG&E's unit forecast for residential connections) is significantly higher than in recent years.[2156] TURN substitutes its own residential permits forecast based on a five-year historical average, escalated based on the five-year (2015-2019) average growth rate for permits.[2157]

PG&E has described the factors that support RCG's finding that residential permitting is likely to grow more quickly than in recent years, including the end of COVID-19 restrictions, strong consumer demand, and incentives for developers to increase the pace of development.[2158] Although TURN suggests that these factors only contribute to housing demand, and say nothing about supply[2159], RCG specifically rebutted that contention and outlined how current housing need and legislative changes point to an increase in housing

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2154 PG&E-04, WP 18-26, Table 18-26, line 12.

2155 TURN Amended Opening Brief, p. 488.

2156 TURN Amended Opening Brief, pp. 484-486.

2157 TURN Amended Opening Brief, pp. 487-488.

2158 PG&E Opening Brief, p. 558; PG&E-17, p. 18-10, line 22 to p. 18-12, line 12; PG&E-04, WP 18-29 to WP 18-41 (RCG whitepaper included in PG&E's workpapers); PG&E-17, p. 18-AtchA-2 to p. 18-AtchA-3 (RCG whitepaper included in PG&E's rebuttal).

2159 TURN Amended Opening Brief, p. 487.

production in the coming years relative to the 2015-2019 period used as the basis for TURN's alternative permits forecast.[2160]

Finally, even if TURN is right that PG&E's permitting forecast is overstated, that does not mean that PG&E's funding request for residential connections is unreasonable. PG&E's 2021 recorded cost for residential connections was $265.7 million, significantly higher than PG&E's forecast of $167.5 million, and about equal to PG&E's 2023 forecast spending of $261.6 million.[2161] In its Opening Brief, TURN argues that this is irrelevant because most of PG&E's higher than forecast expenditures in 2021 were due to higher than expected unit costs, not additional units of work.[2162] TURN is effectively asserting that because it has only challenged PG&E's unit forecast, that Commission should not consider other aspects of the forecast in making its funding decisions. This approach is unreasonable because the forecast should be considered holistically. For example, one of the factors that TURN points to as a reason why residential permitting is unlikely to rise to the level forecast by PG&E is lower consumer demand because of changes in interest rates due to inflation since PG&E made its forecast.[2163] However, those same inflationary pressures will inevitably lead to higher than forecast increases in unit costs (as evidenced by PG&E's higher than forecast unit costs in 2021.)[2164] Under these circumstances, PG&E's 2023 forecast, which is less than 2 percent

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2160 PG&E-17, p. 18-AtchA-3.

2161 PG&E Opening Brief, 559. PG&E also spent significantly more than forecast on residential connection in 2018 ($28 million over forecast) and 2020 ($41.7 million over forecast). Compare A.18-12-009, HE-19: Exhibit (PG&E-04), WP 16-29, Table 16-28, line 10 (2018 and 2020 forecast amounts) with PG&E-04, WP 18-26, Table 18-26, line 10 (2018 and 2020 recorded amounts).

2162 TURN Amended Opening Brief, pp. 491-494.

2163 TURN Amended Opening Brief, pp. 490-491.

2164 Compare PG&E-04, WP 18-26, Table 18-26, line 10 (2023 forecast cost for Residential Expenditures of $261.6 million) with TURN-307, PG&E's response to Data Request TURN_238-Q02, dated 8/5/22 (2021 recorded costs for Residential Expenditures of $256.7 million), p. 2, line 10. [261.6/256.7 = 1.019].

higher than PG&E's 2021 recorded costs, is reasonable.[2165] TURN's recommended $53.9 million forecast reduction, approximately 20 percent of PG&E's forecast, would result in insufficient funding for PG&E's mandated New Business residential connections work.

4.18.3 The Commission Should Adopt PG&E's Plug-In Electric Vehicles Forecast

TURN proposes that PG&E's 2023-2026 capital forecast for the Electric Vehicle Charge 2 (EVC2) portion of MWC 16 be reduced to match whatever the number of charging ports that PG&E is authorized in the EVC2 Application proceeding.[2166] PG&E agrees that the EVC2 application should be the basis for funding but believes that given uncertainty around the timing for the decision in the EVC2 proceeding, that PG&E's GRC funding should be based on its forecast in the EVC2 proceeding. The issue is discussed more fully in PG&E's Opening Brief.[2167]

4.18.4 Cal Advocates' Recommended Reduction To PG&E's Transformer Purchase Forecast Should Not Be Adopted

The New Business program under MWC 16 purchases distribution transformers for all of PG&E's electric distribution programs.[2168] Cal Advocates recommends a $12.0 million reduction to PG&E's Transformer Purchases forecast.[2169] This reduction is proportionate to Cal Advocates' recommended reductions to the forecast for three Electric Distribution activities—Pole Replacement (MWC 07), New Business (MWC 16), and Major Emergency (MWC 95) – that use transformers.[2170] As explained in PG&E's Opening Brief, this recommendation should not be adopted because the proposed reductions to MWCs 07, 16, and

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2165 Compare PG&E-04, WP 18-26, Table 18-26, line 8 (2021 forecast unit cost for Residential - Other of $4,808) with TURN-307, PG&E's response to Data Request TURN_238-Q02, dated 8/5/22 (2021 recorded unit cost for Residential-Other of $6,776), p. 2, line 8.

2166 TURN-08, p. 1, lines 11-12.

2167 PG&E Opening Brief, p. 561.

2168 PG&E-04, p. 18-33, lines 2-3.

2169 Cal Advocates Opening Brief, p. 261, Table 3 (line item for Transformer Purchases).

2170 Cal Advocates Opening Brief, pp. 270-271.

95 upon which it depends should not be adopted.[2171] PG&E provides further support for its position elsewhere in this Reply Brief.[2172]

4.19 Rule 20A

TURN is the only party that recommends forecast reductions for PG&E's Rule 20A program tracked in MWC 30.[2173] TURN argues that the Rule 20A forecast should be based on a 5-year average instead of a 3-year average, and that PG&E's forecast should be reduced to account for the accumulated balance in PG&E's Rule 20A balancing account.[2174] These arguments are the same ones TURN made its prepared testimony. PG&E has fully responded to TURN's arguments in its rebuttal testimony and Opening Brief and will not repeat that material here.[2175] TURN's Opening Brief does not attempt to refute PG&E's rebuttal showing that a three-year average is a more appropriate forecast basis than a five-year average.

TURN's one new argument concerns the Rule 20A balancing account. TURN asserts that PG&E spent less than its authorized forecast for Rule 20A in 2021 and then argues that this underspending invalidates PG&E's rationale for its proposal to retain part of the balance in the Rule 20A balancing account (*i.e.*, to provide flexibility to perform more project work than forecast if resources become available).[2176] But the fact that PG&E underspent its forecast in one year does not mean that PG&E will not be in position to do more work than forecast in future years. As PG&E has already explained, there are a large number of communities with projects in its Rule 20A queue; retaining a balance in the Rule 20A balancing account will allow

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2171 PG&E Opening Brief, p. 561.

2172 *See* Sections 4.12 (MWC 07), 4.18 (MWC 16), and 4.6 (MWC 95).

2173 TURN Amended Opening Brief, p. 497.

2174 TURN Amended Opening Brief, p. 494-497.

2175 PG&E-17, p. 19-4, line 11 to p. 19-5, line 27; PG&E Opening Brief, pp. 562-564.

2176 TURN Amended Opening Brief, pp. 497-498.

PG&E to pursue more of those projects if construction resources are available.[2177] The Commission should reject TURN's recommendation and provide PG&E that flexibility.

4.20 Electric Distribution Data Management And Technology

Cal Advocates is the only party that recommends forecast reductions for PG&E's Electric Distribution Data Management and Technology programs.[2178] The disputed programs are tracked in MWCs GE (Electric Distribution Mapping) and JV (Maintain IT Applications and Infrastructure); PG&E's capital forecasts in this area are uncontested.[2179] Cal Advocates also makes a non-financial recommendation regarding PG&E's project estimating tool (PET), used to estimate most of PG&E's IT-related project costs.[2180] PG&E will discuss each of Cal Advocates' recommendations below.

4.20.1 PG&E Has Already Fully Addressed Cal Advocates' Recommendations For MWCs GE And JV

Cal Advocates recommends forecast reductions to MWCs GE and JV to bring them more in line with historical recorded costs.[2181] The discussion of MWCs GE and JV in Cal Advocates' Opening Brief restates almost verbatim the prepared testimony that Cal Advocates submitted.[2182] Cal Advocates' Opening Brief does not refute, or even mention, PG&E's rebuttal testimony. PG&E's rebuttal testimony and Opening Brief thoroughly address the arguments in Cal Advocates' prepared testimony.[2183]

2177 PG&E Opening Brief, pp. 563-564.

2178 Cal Advocates Opening Brief, pp. 287-291 (discussing expense recommendations for MWCs GE and JV). Note that Cal Advocates mistakenly included its discussion of MWC GE and JV in the Integrated Grid Planning and Grid Modernization section of its Opening Brief.

2179 PG&E's Opening Brief, p. 564.

2180 Cal Advocates Opening Brief, p. 272.

2181 Cal Advocates Opening Brief, pp. 287-291.

2182 Compare CALPA-04, p. 31, line 16 to p. 35, line 5 with Cal Advocates Opening Brief, pp. 289-291.

2183 PG&E-17, p. 20-5, line 11 to p. 20-11, line 6; PG&E Opening Brief, pp. 565-568.

4.20.2 Cal Advocates' Recommendation Regarding The Project Estimating Tool Should Not Be Adopted.

Cal Advocates recommends that the Commission require PG&E to implement several process changes to its PET. The discussion of the PET in Cal Advocates' Opening Brief restates almost verbatim the prepared testimony Cal Advocates submitted.[2184] PG&E addressed all of Cal Advocates arguments in its rebuttal testimony[2185]; Cal Advocates' Opening Brief does not refute, or even mention, PG&E's rebuttal testimony. PG&E did not include its rebuttal arguments in its Opening Brief and will therefore restate them here for completeness sake.

Cal Advocates' main criticism is that manual overrides made during the development of PET estimates generally have a noticeable effect on the project cost. Further, Cal Advocates argues that some of the estimates in PG&E's PET are highly simplistic.[2186] PG&E disagrees with that criticism. The purpose of the PET is to provide a standard, consistent estimating approach across all of IT using a documented assumption-driven methodology. The PET is not a proxy for a detailed job estimate or business case because it represents an investment estimate at a high level and a specific point in time. While it is true that manual adjustments to the PET can have a noticeable effect on the project cost, that does not mean that the cost estimate that incorporates a manual adjustment will not be accurate. Input provided by subject matter experts familiar with an aspect of the proposed solution can provide additional granularity for a specific investment that the unadjusted PET cannot accommodate. IT projects can and do have wide variability in cost depending on a number of factors. It is not possible for a standard tool to address each and every factor or assumption that can change during the life of a project. PG&E

2184 Compare CALPA-06, p. 96, line 9 to p. 100, line 21 with Cal Advocates Opening Brief, pp. 273-278.

2185 PG&E-17, p. 20-11, line 9 to p. 20-13, line 12.

2186 CALPA-06, p. 97, lines 3-8.

specifically relies on subject matter expertise to determine where manual adjustments are necessary to improve initial cost estimates based on the unadjusted output of the PET tool.[2187]

The changes recommended by Cal Advocates are not necessary for demonstrating the viability of the PET. Cal Advocates has based its recommendation on a fundamental misunderstanding of the purpose of the PET. First, presenting an analysis comparing the PET to actual project costs would not be viable due to the differing level of assumptions and the passage of time. Second, the PET cannot accommodate all factors used to produce a final project estimate and may not even retain those initial manual overrides in the execution of the project. Third, PG&E does not create a resource plan which would more precisely determine the portion of contractor versus internal labor until the project has developed an execution plan, which is much later than when initial project estimates are developed using the PET. PG&E will continue to make improvements to the PET and disclose any significant changes to the CPUC, as has been done historically.[2188] Cal Advocates' proposal for changes to the PET should not be adopted.

4.21 Integrated Grid Platform And Grid Modernization Plan

Cal Advocates is the only party that makes forecast recommendations for PG&E's Integrated Grid Platform programs. With regard to expense, Cal Advocates recommends a reduction to PG&E's forecast for Emerging Technology (MWC AT).[2189] With regard to capital, Cal Advocates recommends reductions to PG&E's forecasts for the Advanced Distribution Management System (ADMS) and the Distributed Energy Resources Management System (DERMS) (MWC 63); some of these reductions are premised on moving consideration of part of the MWC 63 forecast into another proceeding.[2190]

2187 PG&E-17, p. 20-11, line 20 to p. 20-12, line 3.

2188 PG&E-17, p. 20-12, line 28 to p. 20-13, line 12.

2189 Cal Advocates Opening Brief, pp. 291-293.

2190 Cal Advocates Opening Brief, pp. 278-287.

The discussion of MWC AT and MWC 63 in Cal Advocates' Opening Brief restates almost verbatim the prepared testimony that Cal Advocates submitted.[2191] Cal Advocates' Opening Brief does not refute, or even mention, PG&E's rebuttal testimony. For example, Cal Advocates continues to assert that PG&E's forecast for MWC AT is $17.2 million[2192] when PG&E stated in rebuttal that it had lowered its forecast to $2.1 million to reflect the Commission's decision to allow PG&E to continue administering its EPIC program.[2193] PG&E's rebuttal testimony and Opening Brief thoroughly address the arguments in Cal Advocates' prepared testimony.[2194] PG&E will not repeat that material here.

4.22 Electric Distribution Support

Cal Advocates is the only party that recommends a forecast reduction to PG&E's Electric Distribution Support programs; the only disputed area is the forecast for Miscellaneous Expense (MWC AB).[2195] The discussion of MWC AB in Cal Advocates' Opening Brief restates almost verbatim the prepared testimony that Cal Advocates submitted.[2196] Cal Advocates' Opening Brief does not refute, or even mention, PG&E's rebuttal testimony. PG&E's rebuttal testimony and Opening Brief thoroughly address the arguments in Cal Advocates' prepared testimony.[2197]

2191 Compare CALPA-04, p. 37, line 14 to p. 38, line 14 and CALPA-06, p. 102, line 1 to p. 112, line 19 with Cal Advocates Opening Brief, pp. 278-287 and 291-293.

2192 Cal Advocates Opening Brief, p. 292.

2193 PG&E-17, p. 21-16, lines 13-19.

2194 PG&E-17, p. 21-7, line 9 to p. 21-16, line 20; PG&E Opening Brief, pp. 569-575.

2195 Cal Advocates Opening Brief, p. 294.

2196 Compare CALPA-04, p. 40, line 3 to p. 41, line 24 with Cal Advocates Opening Brief, pp. 295-296.

2197 PG&E-17, p. 22-4, line 7 to p. 22-7, line 25; PG&E Opening Brief, pp. 576-578.

4.23 Community Rebuild Program

4.23.1 Overview

The Commission should approve PG&E's TY 2023 expense forecast for the Community Rebuild Program presented as: (1) $13.781 million in rebuttal testimony;[2198] and (2) $15.548 million in the JCE with the September escalation adjustment.[2199]

The Commission should approve PG&E capital expenditures forecast presented as: $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 in rebuttal testimony;[2200] and (2) 90.222 million in 2021, $135.315 million in 2022, $131.690 million in 2023, $112.305 million in 2024, $74.431 million in 2025, and $19.409 million in 2026 in the JCE with the September escalation adjustment.[2201, 2202]

In its Opening Brief, Cal Advocates reiterates its recommendation to remove PG&E's entire Community Rebuild Program capital forecast from the GRC, arguing that recovery of these program costs should instead occur through the CEMA application process.[2203] TURN similarly recommends in its Opening Brief that the Commission deny rate recovery of any costs associated with the program until PG&E submits a single CEMA application that addresses

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2198 PG&E-17, p. 2-4, Table 2-1, line 23.

2199 PG&E-64, p. 3-2, Table 3A-1, line 93.

2200 PG&E-17, p. 2-5, Table 2-2, line 21 (2021); p. 2-6, Table 2-3, line 21 (2022); and p. 2-7, Table 2-4, line 21 (2023).

2201 PG&E-67, WP 3, line "[Exhibit 4, Chapter] 23," MWC 95.

2202 Forecast amounts in Section 4.23.1 refer to Electric Distribution. There are additional Community Rebuild forecast costs in Section 3 (Gas Operations) and Section 6 (Customer and Communication).

2203 Cal Advocates Opening Brief, p. 299-305; CALPA-05, p. 46, line 26 to p. 47, line 5, and p. 51, lines 15-17.

PG&E's role in causing the 2018 Camp Fire and demonstrates that the costs are reasonable for rate recovery purposes.[2204]

As explained in more detail below, the Commission should deny Cal Advocates' and TURN's arguments, which are premised incorrectly on their characterization that PG&E's Community Rebuild project from 2023-2026 relates to CEMA restorations activities. The Community Rebuild project extends beyond typical CEMA activities.

4.23.2 Community Rebuild Costs Forecast In The GRC Should Not Be Subject To CEMA

PG&E's forecasts for the Community Rebuild Program 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. Public Utilities Code 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.

PG&E's CEMA tariff states that "[t]he purpose of the CEMA is to recover the costs associated with the restoration of service and PG&E facilities affected by a catastrophic event declared a disaster or state of emergency by competent federal or state authorities."[2205] PG&E's CEMA costs incurred from 2018-2022 (still unrecovered) included restoring overhead electrical power lines following the fire and connecting service to customers who were able to accept service immediately after the fire. These like-for-like restore/repair activities are what is traditionally recorded for recovery in CEMA.

2204 TURN Amended Opening Brief, p. 499; TURN-13, p. 1, line 23 to p. 2, line 5, and p. 4, lines 3-7.

2205 PG&E Electric Preliminary Statement, Part G (Sept. 3, 2022), Section 1 (Purpose).

PG&E's Community Rebuild activities forecast in the GRC from 2023-2026 are different than traditional like-for-like repair/restore activities under CEMA. The Community Rebuild work planned for 2023-2026 mostly involves moving overhead line underground in order to mitigate wildfire risks, as opposed to the CEMA work of restoring the overhead lines that had been destroyed by the fire.[2206] To be sure, some limited CEMA restoration work will continue post-2022. For example, when PG&E restores service to a customer who has returned to rebuild their property, the costs associated with restoring those costs may be CEMA costs. In addition, any remaining like-for-like restoration activities still to be completed may be CEMA costs. But any such costs will be recorded in the CEMA, and are not included in this GRC. Explaining this distinction, PG&E's opening testimony stated that "[t]he scope of [Community Rebuild] excludes costs for [CEMA] emergency response activities . . . and covers the next phase of work to rebuild the distribution assets to meet the long-term needs of the community . . . ."[2207] Thus, the sequence of PG&E's activities can be described as: (1) 2018-2022 CEMA work involving the temporary like-for-like installation/repair of overhead electric facilities to restore service following the 2018 Camp Fire;[2208] followed by (2) 2023-2026 Community Rebuild activities to underground overhead electric lines in the Town of Paradise and surrounding communities for wildfire mitigation and other safety purposes.[2209] The first sequence – PG&E's 2018-2022 like-for-like overhead restoration work and associated costs – are subject to CEMA cost recovery.[2210] The second sequence – PG&E's 2023-2026 Community Rebuild undergrounding work – should be deemed to be non-CEMA work recoverable in the GRC on a forecast basis.

2206 PG&E-04, p. 23-20, lines 9-21; p. 23-24, Table 23-9, line 3.

2207 PG&E-04, p. 23-1, lines 18-21.

2208 PG&E-04, p. 23-1, lines 18-19.

2209 PG&E-04, p. 23-1, lines 20-22; p. 23-11, lines 20-26.

2210 Some restoration work will continue. For example, when PG&E restores service to a customer who has returned to rebuild their property, the costs associated with restoring those costs may be CEMA costs.

This is not just semantics. For example, in D.92-12-016, the Commission determined that the undergrounding of overhead electric facilities in the following the October 20-23, 1991 Oakland/Berkeley Hills fires should not be recovered through the CEMA.[2211] Similar to the situation in Paradise, there was a community desire to underground the lines given the fire that had occurred. This decision has parallels here because there are material differences between the scope of work and costs in the two work sequences (overhead like-for-like CEMA restoration work versus non-CEMA Community Rebuild undergrounding work) and the rate recovery should be treated separately. The undergrounding of overhead lines should not be construed as a CEMA activity.

Ignoring the difference between PG&E's initial 2018-2022 CEMA overhead-facilities restoration work and subsequent 2023-2026 Community Rebuild undergrounding work, Cal Advocates and TURN appear to assume that the undergrounding work should constitute CEMA work merely because the work is taking place in Paradise close in time and location to PG&E's CEMA work. But this should not be the case. The dispositive factor between what qualifies as CEMA work versus non-CEMA work is the nature of the work, not temporal or locational coincidences. At some point, when PG&E performs work in Paradise, 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. For example, post-2022 system improvements following the initial 2018-2022 restoration of services should not constitute as CEMA activities. In this sense, the Community Rebuild program, which is part of PG&E's 10,000 mile undergrounding program, should be viewed as a system-improvement project, performed after CEMA activities

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2211 D.92-12-016, p. 25, Conclusion of Law (COL) 10.

had been completed. For forecasting purposes in this GRC, PG&E's Community Rebuild forecasts covers 2023-2026.

4.23.3 There Is No Prohibition Against Recovery Of Community Rebuilding Undergrounding Costs

Both TURN and Cal Advocates cite D.20-05-019 in support of their recommendations, with both arguing that the decision requires PG&E to demonstrate the reasonableness of its actions prior to the 2018 Camp Fire in order to obtain cost recovery of its Community Rebuild costs.[2212] TURN also cites to D.17-11-033 (SDG&E WEMA Decision) and D.21-08-024 (SCE CEMA Decision) as requiring a reasonableness showing of PG&E's actions prior to the 2018 Camp Fire.[2213] PG&E acknowledges that this standard pertains to 2018-2022 CEMA cost recovery. But these decisions are inapposite here and it would be incorrect to apply a CEMA-recovery standard to PG&E's 2023-2026 forecast for Community Rebuild undergrounding work, which as discussed above, extends well beyond traditional CEMA restoration work. Thus, under this CEMA-review standard, PG&E would be required to demonstrate the reasonableness of its pre-Camp Fire actions in order to obtain CEMA cost recovery of its 2018-2022 work to restore overhead lines or other like-for-like restoration work beyond 2023. But this standard should not be construed to prohibit recovery of reasonable non-CEMA costs associated with 2023-2026 undergrounding work that will provide superior and longer-lasting benefits to customers beyond the initial restoration work completed 2018-2022.

In addition, PG&E has identified all CEMA recorded costs subject to disallowance ordered in D.20-05-019 for activities associated with rebuilding PG&E infrastructure destroyed

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2212 Cal Advocates Opening Brief, pp. 302-303; TURN Amended Opening Brief, p. 501; TURN-13, p. 5, line 12 to p. 6, line 6.

2213 TURN Amended Opening Brief, pp. 501-502.

by the 2018 Camp Fire.[2214] These CEMA-related disallowed amounts are not included in PG&E's forecast or requested 2023 GRC RRQ.[2215]

4.23.4 The GRC Is The Appropriate Venue To Review Community Rebuild Undergrounding Costs

TURN further argues that PG&E's inclusion of 2023-2026 Community Rebuild costs in the GRC would inappropriately fragment the review of costs relating to PG&E's CEMA restoration efforts in Paradise, claiming that TURN is unaware "of any single CEMA-eligible event for which the Commission reviewed the costs [] in more than one proceeding, or relied on forecasted rather than recorded costs."[2216] TURN is wrong.

First, as established above, PG&E's 2023-2026 Community Rebuild work is not CEMA work. Therefore, there is no fragmented CEMA review.

Second, even if there was an expectation that 2018-2022 CEMA costs should be reviewed concomitant with 2023-2026 Community Rebuild cost (which there is no requirement to do), TURN is wrong factually about CEMA-event costs only being considered in a single applications. PG&E has historically filed cost-review applications annually (or near annually) and in doing so frequently seeks recovery of costs for single projects across multiple CEMA proceedings. TURN has been an active intervenor in PG&E's Wildfire Mitigation Catastrophic Event (WMCE) proceedings, including A.20-09-019 and A.21-09-008 that sought recovery of costs for various projects across the two proceedings. TURN's assertion that it is not aware of this approach undermines its credibility on this issue.

What is more, PG&E's approach of seeking recovery of 2023-2006 Community Rebuild costs in this GRC separate from the 2018-2022 CEMA costs is the most-straightforward way to address cost recovery for the undergrounding work. For example, it would make very little sense

2214 D.20-05-019, Appendix A, p. 3.

2215 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).

2216 TURN Amended Opening Brief, pp. 504.

to separate the Commission's review of PG&E's 10,000 mile undergrounding proposal and the Community Rebuild undergrounding project, which is part of that overall project. And it again bears mentioning that PG&E has identified all CEMA recorded costs subject to disallowance ordered in D.20-05-019 – those costs are not sought in this GRC. PG&E may determine that there are no 2018 Camp Fire CEMA costs eligible for recovery.

Finally, there is nothing prohibiting cost-recovery of Community Rebuild costs on a forecast basis. Again, the 2023-2026 costs are not CEMA costs, and they can be accurately forecast. Indeed, costs for capital projects are typically presented on a forecast basis in the GRC pursuant to the rate case plan. Therefore, cost recovery in the GRC is an appropriate cost recovery mechanism.

4.23.5 PG&E Presented Sufficient Evidence Demonstrating The Reasonableness Of The Community Rebuild Program

TURN also questions PG&E's analysis of alternatives to undergrounding and argues that PG&E has not demonstrated the reasonableness of the Community Rebuild program.[2217] TURN misconstrues, in particular, PG&E's close coordination with city planning efforts and public commitment to underground as though that it is the only basis for PG&E's decision to underground electrical assets. TURN ignores the ample evidence presented by PG&E explaining that in addition to supporting city planning efforts, the undergrounding supports wildfire mitigation in Tier 2 and 3 HFTD areas and safety in the event a fire occurs.[2218] In regard to safety issues, in particular, many distribution poles fell into the streets and blocked access to egress routes during the fire.[2219] The undergrounding of assets will therefore not only reduce wildfire risks from power lines in the area, it will help ensure access to safe egress routes if there

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2217 TURN Amended Opening Brief, p. 500.

2218 PG&E-04, p. 23-11, lines 15-19.

2219 PG&E-04, p. 23-11, lines 20-21.

is another wildfire (regardless of the source of ignition).[2220]

In sum, PG&E has demonstrated the reasonableness of the 2023-2026 Community Rebuild work to provide wildfire mitigation and safety to a community that was devastated by a catastrophic wildfire. TURN's suggestion that PG&E has not demonstrated the reasonableness of the undergrounding project is inappropriately insensitive and dismissive of the concerns of customers in Paradise and the importance of the reasonable actions being taken by PG&E to protect them from wildfire risks.

4.23.6 PG&E Proposed Treatment Of Community Rebuild Costs Is Appropriate

Cal Advocates and TURN also oppose PG&E's inclusion of pre-2023 capital expenditures in rate base prior to a CEMA reasonableness review being completed.[2221] As more fully discussed in Section 10 of this brief, PG&E is not precluded from including these capital costs in its rate base for purposes of computing its test year and post test year revenue requirements in a GRC.

4.24 Electric Distribution Ratemaking

4.24.1 Wildfire Mitigation Balancing Account (WMBA)

PG&E proposes to continue using the two-way WMBA to record wildfire mitigation related activities, including activities described in this application and new activities described in PG&E's 2022 WMP.[2222] PG&E further proposes that the WMBA reasonableness review threshold for total spending and recorded average per mile for the various types of unit costs be raised from 115 percent to 125 percent.[2223] A two-way balancing account is the appropriate tool for recording costs for wildfire mitigations given increasing wildfire risk and the ongoing impacts of climate change because it allows PG&E to adjust its comprehensive wildfire

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[2220] PG&E-04, p. 23-11, lines 21-26.

[2221] Cal Advocates Opening Brief, p. 302; TURN Amended Opening Brief, pp. 499-500.

[2222] PG&E-04, p. 4-22, line 23 to p. 4-23, line 7.

[2223] PG&E-04, p. 4-24, lines 4-7.

mitigation strategy as needed to keep our customers and communities safe. Raising the reasonable review threshold to 125 percent addresses the uncertainty PG&E faces in forecasting wildfire mitigation work due to the evolving wildfire risk and allows more flexibility to invest in effective mitigations, while still providing clarity on the regulatory review process for any costs over the forecasted amounts.[2224]

Cal Advocates supports continuing the two-way WMBA but opposes PG&E's request to raise the reasonableness review threshold for its WMBA from 115 to 125 percent, arguing there is too much uncertainty in PG&E's WMBA spending to increase the reasonableness review threshold.[2225] PG&E addressed this recommendation in Section 4.2.4.1 of its Opening Brief.

TURN makes three recommendations: (1) the Commission should deny PG&E's request, and instead revise the WMBA to make it a one-way balancing account based on the adopted forecasts for wildfire mitigation programs; (2) on a forward-looking basis, if the Commission believes that these wildfire mitigation activities warrant providing PG&E with an opportunity to recover above-authorized spending on these programs, it should also create a companion Wildfire Mitigation Memorandum Account (WMMA) as the mechanism for recording above authorized spending, subject to later review in a reasonableness review application; and (3) the Commission should also deny PG&E's request for rate recovery of up to an additional 25 percent above the amounts authorized through a Tier 2 advice letter.[2226] PG&E addressed these recommendations in Section 4.2.4.1 of its Opening Brief.

In its Opening Brief, TURN claims that another reason the Commission should reject PG&E's 125 percent balancing account proposal is because PG&E's forecast unit cost is not an aggressive target. Instead, the Commission should adopt a unit cost threshold of $3.0 million per

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2224 PG&E-17, p. 4-7, lines 20-30.

2225 CALPA-04, p. 9, lines 8-13.

2226 TURN-13, p. 23, line 10 to p. 24, line 2.

mile for PG&E's undergrounding program.[2227] TURN argues that PG&E's unit cost forecasts appear much higher when one accounts for what TURN considers a proper comparison to cost per overhead circuit mile.[2228] TURN believes that PG&E's unit cost for undergrounding should be multiplied by 1.25 to reflect the fact the PG&E installs approximately 1.25 miles of underground distribution line for every 1 mile of overhead distribution line removed.[2229] TURN's argument is defective for the reasons explained in Section 4.3.1.4.4 above.

TURN specifically opposes the proposed 125 percent reasonableness review threshold for the WMBA, characterizing it as providing a 25 percent "slush fund" in its Opening Brief (the connotation of which suggests there is some illicit or illegitimate purpose being served).[2230] TURN's rhetoric is inappropriate. While there may be disagreement regarding the funding levels that should be approved, there is nothing improper with PG&E's proposal for a ratemaking mechanism that provides PG&E flexibility to adjust wildfire mitigation activities as circumstances warrant. As noted above in Section 4.1, Commissioner Reynolds stated prior to the start of evidentiary hearings that "our ratemaking process needs to be adaptable enough to adjust [for] the state's wildfire safety approach."[2231] A two-way balancing account does just this – protecting customers by requiring PG&E to refund any overcollections if recorded costs are less than forecasted, but allowing PG&E to adjust its comprehensive wildfire mitigation strategy as needed.

2227 TURN Amended Opening Brief, p. 409.

2228 TURN Amended Opening Brief, pp. 411-412.

2229 TURN states that if PG&E installs 3,297 miles of underground circuits it would de-energize between 2,094 and 2,638 miles of overhead conductor: 3,297 /1.25 = 2,638. TURN Amended Opening Brief, pp. 409-411.

2230 TURN Amending Opening Brief, Summary of Recommendations, p. xx.

2231 Tr. Vol. 4, 509:2-6, Commissioner John Reynolds.

Finally, the CFBF makes two new recommendations regarding cost protection for ratepayers related to PG&E's undergrounding program. PG&E addresses both recommendations in Section 4.3.1.6.3 of this Reply Brief.

4.24.2 Vegetation Management Balancing Account (VMBA)

Cal Advocates recommends that reasonableness review of costs in the VMBA should be triggered if PG&E's recorded costs exceed 125 percent of the five-year average for those costs.[2232] PG&E discusses this recommendation in Section 4.9 above.

TURN makes three recommendations related to PG&E's proposal: (1) the Commission revise the VMBA to return it to being a one-way balancing account;[2233] (2) if the Commission believes PG&E should have an opportunity to recover above-authorized spending on these programs, it should also create a companion Vegetation Management Memorandum Account (VMMA) as the mechanism for recording above-authorized spending, subject to later review in a reasonableness review application;[2234] and (3) the Commission could adopt a treatment of above-authorized spending similar to that adopted for PG&E's AMI program, with 90 percent of up to 6 percent of the authorized amount deemed reasonable and recovered in rates without any after-the-fact reasonableness review. The remaining 10 percent would be absorbed by PG&E's shareholders.[2235] PG&E addressed TURN's arguments in Section 4.24.2 of PG&E's Opening Brief.

[2232] Cal Advocates Opening Brief, p. 177 (Routine VM); p. 181 (Enhanced VM).

[2233] TURN-13, p. 22, lines 4-6.

[2234] TURN-13, p. 22, lines 8-12.

[2235] TURN-13, p. 22, line 13 to p. 23, line 2.

4.24.3 Additional Balancing Accounts

4.24.3.1 Wildfire Mitigation Plan Memorandum Account (WMPMA) For Pole Replacements

Cal Advocates recommends that PG&E remove the 2021 and 2022 forecast capital expenditures for pole replacement tracked in the WMPMA.[2236] PG&E addresses this issue in Section 10.4 of this brief. PG&E also addressed this recommendation in Section 10.4 of its Opening Brief.

4.24.3.2 Community Rebuild Program In CEMA

Cal Advocates recommends that PG&E should continue to track Community Rebuild Program costs in CEMA and that the Commission require PG&E: 1) to remove 2019 and 2020 recorded CEMA capital costs, totaling $155.853 million, from PG&E's results of operation model, and 2) to continue recording costs for the Community Rebuild Program in CEMA for 2023 and beyond.[2237] PG&E discussed this issue in Section 10.4.1 of its Opening Brief.

2236 Cal Advocates Opening Brief, p. 446.

2237 Cal Advocates Opening Brief, p. 448 (fn. omitted).

5. ENERGY SUPPLY (EXHIBIT PG&E-05)

5.1 Forecast

After hearings, TURN and PG&E worked to resolve disputed issues related to our Energy Supply forecasts. As a result of this collaborative effort, TURN and PG&E reached a Stipulation resolving all contested issues between the parties except for escalation, attrition and depreciation issues (TURN-PG&E Energy Supply Stipulation).[2238] The TURN-PG&E Energy Supply Stipulation is included as Appendix E to our Opening Brief. For purposes of determining final values for each of the categories, PG&E and TURN agree that the final escalation amounts adopted by the Commission should apply to amounts in the TURN-PG&E Energy Supply Stipulation.

The stipulated TY 2023 O&M expense forecast for Energy Supply is $575.2 million and the stipulated capital expenditures forecast is $396.4 million in 2023, $376.1 million in 2024, $309.1 million in 2025, and $264.9 million in 2026.

After Opening Briefs were submitted, PG&E and Cal Advocates worked to resolve disputed issues related to our Energy Supply forecasts and were able to resolve all contested issues between the parties (Cal Advocates-PG&E Energy Supply Stipulation). The Cal Advocates-PG&E Energy Supply Stipulation is included as Appendix B to this Reply brief. In summary, Cal Advocates agrees to the stipulated TY 2023 O&M expense and capital expenditure forecasts for Energy Supply reflected in the TURN-PG&E Energy Supply Stipulation. Cal Advocates and PG&E have also agreed to a 2021 recorded hydro capital forecast of $207.891 million and to a TY 2023 expense forecast of $43.786 million for Electric Procurement Administration, which is a subset of the overall Energy Supply expense forecast of $575.2 million agreed to with TURN as described above.

2238 In the Opening Brief we referred to this as the Energy Supply Stipulation. However, because we have reached a separate stipulation with Cal Advocates, as described below, we are using party names to identify each of these stipulations.

The TURN-PG&E Energy Supply Stipulation reflects a compromise of disputed litigation positions on a range of issues addressed by the parties and constitutes an integrated agreement that should be approved in its entirety and without modification. TURN and PG&E jointly request that the Commission approve the provisions of the TURN-PG&E Energy Supply Stipulation instead of any contrary positions articulated in prepared testimony on the resolved issues.[2239]

The Cal Advocates-PG&E Energy Supply Stipulation also reflects a compromise of disputed litigation positions on a range of issues addressed by the parties and constitutes an integrated agreement that should be approved in its entirety and without modification. Cal Advocates and PG&E jointly request that the Commission approve the provisions of the Cal Advocates-PG&E Energy Supply Stipulation instead of any contrary positions articulated in prepared testimony on the resolved issues.

These two Stipulations resolved all contested Energy Supply issues other than Utility Owned Generation (UOG) re-vintaging proposals raised by the Joint Community Choice Aggregators (JCCA). In section 5.8.4, PG&E urges the Commission to reject the JCCA re-vintaging proposals because they unlawfully shift UOG costs to bundled customers.

5.2 Energy Supply Risk Management

No party addressed PG&E's Energy Supply Risk Management testimony.

5.3 Nuclear Operations Costs

The TURN-PG&E Energy Supply Stipulation reasonably resolves the disputed issues between PG&E and TURN regarding the nuclear operations expense and capital forecasts and should be adopted.[2240] No other party addressed nuclear operations costs.

In its Opening Brief, Cal Advocates notes that while it does not take issue with PG&E's nuclear capital expenditure forecast, "plans to postpone retirement in light of Senate Bill 846

2239 PG&E Opening Brief, pp. 593-594, Appendix E, Introduction.

2240 PG&E Opening Brief, pp. 596-599, Sections 5.3.1 and 5.3.2, Appendix E, Sections I (A) and (B).

warrants continued monitoring to ensure that PG&E properly accounts for and separates the costs for the continued operation of Diablo as compared to the costs for it (sic) decommissioning."[2241] Cal Advocates goes on to recommend that "the Commission's decision on the Application should ensure that given SB 846 implementation, cost recovery for Diablo decommissioning will occur in a separate proceeding."[2242]

PG&E would like to clarify that the capital and O&M forecasts for Diablo Canyon presented in this proceeding – as modified by the Stipulation between PG&E and TURN – reflect the existing shutdown dates for Unit 1 (November 2024) and Unit 2 (August 2025) and do not include any forecast of Diablo Canyon decommissioning costs.[2243] Decommissioning costs are accounted for, recovered and reviewed in a separate proceeding, the Nuclear Decommissioning Cost Triennial proceeding (NDCTP).[2244] SB 846 did not modify or replace the NDCTP as the proceeding in which the Commission reviews Diablo Canyon decommissioning costs.[2245]

Pursuant to Senate Bill (SB) 846, the cost of extended operations beyond the expiration of the current operating licenses for Diablo Canyon also will be accounted for and reviewed outside the GRC and the NDCTP, in a proceeding similar to the forecast proceeding for the Energy Resource Recovery Account.[2246] The Commission re-opened A.16-08-006 for the purpose of establishing balancing accounts necessary to ensure proper recording and recovery of the costs associated with continued operation of Diablo Canyon beyond expiration of the current

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2241 Cal Advocates Opening Brief, p. 309.

2242 Id.

2243 Tr. Vol. 14, 2617:21-26, PG&E/Post.

2244 Tr. Vol. 14, 2619:23- 2620:3 TURN/Goodson.

2245 Pub. Util. Code § 712.8(p).

2246 Tr. Vol. 14, 2618:20-2619:3, PG&E/Post.

operating licenses. Any monitoring or review of those costs should and will occur in the context of that proceeding or a successor proceeding addressing continued operations of Diablo Canyon.

5.4 Hydro Operations Costs

With the exception described in Section 5.4.1, the TURN-PG&E Energy Supply Stipulation and Cal Advocates-PG&E Energy Supply Stipulation reasonably resolve the disputed issues between PG&E, TURN, and Cal Advocates regarding the hydro operations expense and capital forecasts. These stipulations should be adopted.[2247]

5.4.1 Use Of 2021 Recorded Data

Cal Advocates recommended use of 2021 recorded data for all hydro capital projects based on its assertion that 2021 recorded costs are "a true representation of PG&E's actual spending."[2248] PG&E did not necessarily oppose the use of 2021 recorded data, but thought that it should be used consistently, for all of PG&E's 2021 capital forecasts.[2249]

In the Cal Advocates-PG&E Energy Supply Stipulation, the parties have agreed that it is reasonable to use 2021 recorded data for all hydro capital projects, resulting in a 2021 forecast of $207.891 million. This agreement is not precedent-setting for other chapters, exhibits or subsequent proceedings.

The Cal Advocates-PG&E Energy Supply Stipulation reasonably resolves the disputed issue between PG&E and Cal Advocates regarding use of 2021 recorded data for hydro capital projects and should be adopted.

5.5 Natural Gas And Solar Generation Operations Costs

The TURN-PG&E Energy Supply Stipulation reasonably resolves the disputed issues between PG&E and TURN regarding the natural gas and solar expense and capital forecasts and

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2247 PG&E Opening Brief, Appendix E, Section II (A)-(D).

2248 CALPA-08, p. 16, lines 3-4.

2249 PG&E Opening Brief, pp. 18-21.

should be adopted.[2250] No other party challenged PG&E's natural gas and solar expense and capital forecasts.

5.6 Energy Procurement And Administration Costs

5.6.1 Acquire And Manage Gas Supply (MWC CV)

PG&E initially forecast $3.130 million for MWC CV in TY 2023. PG&E's original forecast included the cost of five additional staff members to support implementation of PG&E's biomethane program. Cal Advocates proposed a reduction of $0.918 million based on its position that it was unreasonable for PG&E to hire five additional staff to support the biomethane program because the legislation establishing the program does not require additional staffing.[2251] In rebuttal testimony, PG&E agreed to modify its EPP expense request to eliminate the cost of additional staff to implement the biomethane program, but noted that the correct reduction to the TY 2023 EPP expense forecast is $0.685 million.[2252] In the Cal Advocates-PG&E Energy Supply Stipulation, PG&E and Cal Advocates agree to the TY 2023 EPP expense forecast reduction of $0.685 million and that a TY 2023 expense forecast of $2.445 is reasonable for MWC CV. This forecast is consistent with the TURN-PG&E Energy Supply Stipulated TY 2023 O&M expense forecast for Energy Supply of $575.2 million.

The Cal Advocates-PG&E Energy Supply Stipulation reasonably resolves the disputed issues between PG&E and Cal Advocates regarding the TY 2023 Electric Procurement Administration forecast and should be adopted.

5.7 Energy Supply Technology Programs

No party had any recommendations specific to PG&E's Energy Supply Technology Programs forecast.

2250 PG&E Opening Brief, pp. 613-617, Appendix E, Section III (A)-(G).

2251 CALPA-08, p. 25, line 1 to p. 26, line 14.

2252 PG&E-18, p. 6-7, lines 7-10.

5.8 Energy Supply Ratemaking

TURN and JCCA are the only parties taking positions on Energy Supply Ratemaking issues. The TURN-PG&E Energy Supply Stipulation reasonably resolves the disputed energy supply ratemaking issues between PG&E and TURN and should be adopted. The issues raised by JCCA are addressed in Section 5.8.4 below.

5.8.1 Hydro Decommissioning Accrual

The Stipulation between PG&E, Cal Advocates and Cal Trout supporting a $48 million annual hydro decommissioning accrual described and supported in PG&E's Opening Brief is reasonable and should be adopted.[2253] No other party addressed the hydro decommissioning accrual.

5.8.2 Hydro Licensing Balancing Account

The TURN-PG&E Energy Supply Stipulation reasonably resolves the disputed issues between PG&E and TURN regarding the operation of the Hydro Licensing Balancing Account (HLBA) and should be adopted.[2254] No other party addressed the HLBA.

5.8.3 Helms Capacity Memorandum Account

The TURN-PG&E Energy Supply Stipulation reasonably resolves the disputed issues between PG&E and TURN regarding the Helms Capacity Memorandum Account (HCMA) and should be adopted.[2255] No other party addressed the HCMA.

5.8.4 Utility Owned Generation Vintaging

PG&E's application and supporting testimony in this proceeding 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 PG&E

[2253] PG&E's Opening Brief, pp. 620-621. The stipulation was marked as an exhibit at the hearing (*i.e.*, PG&E-30) and entered into the record.

[2254] PG&E Opening Brief, pp. 622-623, Appendix E, Sections IV(A) and IV(C).

[2255] PG&E Opening Brief, pp. 623-624, Appendix E, Section IV(B).

does not propose any changes to the vintaging or the current framework for assigning cost responsibility to bundled and unbundled customers for UOG. PG&E supports continuation of the current approach that was directed by the Commission in D.18-10-019. The current approach appropriately ensures that customers pay for the costs of investments made on their behalf, including the costs of decommissioning a resource. In contrast, the Joint Community Choice Aggregators (JCCA) proposals would allow CCA customers to avoid financial responsibility for investments made to serve CCA customers by shifting the ongoing costs of these assets to bundled customers. This is inconsistent with law and Commission precedent.

5.8.4.1 The Commission Should Reject JCCA's Assertions That PG&E Failed To Meet A Hypothetical, Inapplicable Burden Of Proof In This Proceeding As Well As Its Attempt To Establish A New Burden Of Proof For Future GRC Proceedings

JCCA asserts that "PG&E has the burden to affirmatively establish the reasonableness of all aspects of its Application, including its proposed allocation of costs and proposed vintage assignments for UOG resource revenue requirements in this this case."[2256] PG&E's request related to UOG assets in this application is that the Commission find reasonable its forecasts of capital and O&M for these assets.[2257] Accordingly, the Commission's determination in this case is whether PG&E has demonstrated by a preponderance of the evidence that its forecast costs are just and reasonable such that they should be included in customer rates.[2258]

PG&E did not propose vintages for its UOG assets in this proceeding nor did it unilaterally choose the UOG asset vintage assignments. The Commission established the vintaging assignments for PG&E's UOG assets in its decisions addressing PCIA ratemaking.[2259] The Commission did not direct PG&E, either in its PCIA ratemaking decisions

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2256 JCCA Opening Brief, p. 5.

2257 See 2023 General Rate Case Application of PG&E (June 30, 2021), p. 16.

2258 PG&E Opening Brief, pp. 12-13.

2259 See generally, D.08-09-012.

or in its 2020 GRC decision, to address the reasonableness of Commission-approved vintages for its UOG assets in this proceeding. Importantly, the Commission did not even direct that PG&E meet the affirmative burden JCCA suggests in D.18-10-019, the decision in which the Commission found that "it is possible that plant investments for certain upgrades may justify a different vintage treatment for those investments than for the underlying facility. But any such analysis must be fact-specific to the plants and spending in question and is better suited to a GRC evaluating such spending."[2260] There's no way to read this language to impose an affirmative burden on PG&E to justify the reasonableness of Commission-approved vintage assignments in this GRC. The Commission should disregard JCCA's assertion that PG&E somehow failed to meet a hypothetical, inapplicable burden of proof.

Similarly, the Commission should reject the JCCA proposal to impose a new burden of proof establishing the reasonableness of investment in UOG assets in future GRC proceedings. PG&E agrees with JCCA that unbundled customers pay only a portion of PG&E's electric generation rates for generation assets PG&E acquired to serve them before they departed.[2261] PG&E also agrees that it is vitally important – indeed, it is required by statute - that the Commission prevent unlawful costs shifts between unbundled and bundled customers.[2262] PG&E disagrees, however, that the effort to prevent cost shifting requires the Commission to mandate that PG&E's prepared direct testimony in future GRCs to address: (1) details of any proposal for any 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 PG&E is making these new investments; and (3) the appropriate vintaging treatment for each asset in light of its testimony.[2263]

2260 D.18-10-019, p. 135.

2261 JCCA Opening Brief, p. 2.

2262 JCCA Opening Brief, p. 2.

2263 JCCA Opening Brief, p. 38.

The JCCA proposal is grounded in its misunderstanding of the cost causation and cost allocation principles followed by the Commission. JCCA asserts that PG&E must demonstrate that investments in existing UOG assets directly benefit unbundled customers in order to recover the cost of those investments from unbundled customers. In fact, as articulated in D.14-12-024, "the principle of cost causation means that costs should be borne by those customers who cause the utility to incur the expense, not necessarily by those who benefit from the expense."[2264] It is undisputed that PG&E acquired, developed, operates and maintains its legacy UOG assets on behalf of all customers, bundled and unbundled. The Commission should reject JCCA's inaccurate interpretation of applicable cost causation principles. In this GRC, prior GRCs and future GRCs, all of PG&E's investments in its legacy UOG assets are proposed on behalf of <u>all</u> customers in PG&E's service territory, including unbundled load. We made the initial investment on behalf of all customers, and all subsequent investments are to retain/extend that initial investment. For as long as a legacy UOG asset is in the PCIA portfolio, it continues to benefit the same set of customers it benefitted initially. Consistent with the Commission directive in D.18-10-019, the only exceptions - and PG&E hasn't proposed any yet - is if there was a significant overhaul and upgrade of a legacy UOG asset, such as construction of an additional powerhouse or additional of a new generating unit or significant and substantial upgrade increasing the capacity of a UOG asset.[2265] Efficiency upgrades, equipment refurbishment or replacement, and minor increases in capacity would not warrant revintaging. Based on the Commission's statements in D.14-12-024, and in the absence of a significant and substantial expansion or upgrade, extending the life of a legacy UOG asset also should never result in revintaging that asset.

2264 D.14-12-024, p. 48, and p. 78, FOF 59.

2265 D.18-10-019, p. 135.

5.8.4.2 JCCA Proposals To Sunset CCA Customer Responsibility For UOG Unlawfully Shift Costs To Bundled Customers

A central element of the JCCA hydro re-vintaging and framework proposals is assignment of an "end date" for CCA customer responsibility for the ongoing costs to maintain UOG assets.[2266] JCCA proposes an end date as the initial expected end of life of the UOG asset reflected in the depreciation study presented in PG&E's 2014 GRC.[2267]

There is no support for the notion that the Legislature's intent in adopting the statutory indifference requirement was to at some point shift full responsibility for the costs of PCIA-eligible resources to remaining bundled customers. Indeed, the plain language of Sections 365.2, 366.2 and 366.3 indicate exactly the opposite – that is, bundled customers may not experience "any cost increases" due to load departure. The Commission's obligation to preserve customer indifference applies so long as PCIA-eligible resources developed or procured to serve departing load customers remain in the utility's portfolio, whether operating or being decommissioned.

The Commission previously considered and rejected a proposal to define a sunset date, concluding that it "should not adopt a sunset of the obligation to pay the PCIA."[2268] More specifically, the Commission found that "section 366.2(f)(2) bars the Commission from sunsetting CCA customer obligations vis-à-vis the expiration of all then-existing electricity purchase contracts," and that, "a sunset provision will reduce incentives for parties to actively participate in any allocation or auction process that may take place…."[2269] In rejecting a sunset date, the Commission implicitly understood that UOG is a long-term asset that will require ongoing investment and repair to retain its value and that departed load shouldn't be able to shirk responsibility for assets procured to serve load at ANY point in a facilities life. It also suggests that the Commission agreed with parties in that proceeding who argued that limiting the number

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2266 JCCA Opening Brief, p. 40.

2267 JCCA Opening brief, p. 40.

2268 D.18-10-019, p. 158, COL 18.

2269 D.18-10-019, p. 82.

of years CCA customers would be responsible for the PCIA would result in an unlawful cost shift from unbundled to bundled customers.

JCCA's argument that the current PCIA ratemaking framework results in CCA customers paying UOG costs in perpetuity ignores the fact that the CCA or its customer have the opportunity to pre-pay the PCIA obligation on a one-time basis in order to be relieved of the PCIA obligation going forward.[2270] That "buyout" is the appropriate regulatory path for a CCA that wishes to terminate its PCIA obligations, and so the Commission should not entertain CCA efforts to avoid their PCIA obligations through revintaging of legacy UOG assets that were procured on behalf of all customers.

5.8.4.3 The JCCA Hydro Re-Vintaging Proposal Is Fatally Flawed In Failing To Address CCA Customer Responsibility For Remaining Net Book Values And Decommissioning Costs

Even if the Commission adopts a date on which departed load customers should no longer be presumptively responsible for any portion of the ongoing revenue requirement to operate and maintain a UOG resource – and it should not for all of the reasons described above– departing load customers must remain responsible for the remaining net book value and decommissioning costs of UOG resources. The Commission must ensure that customers who received the benefit of energy and capacity from these resources also contribute to the cost to decommission them.[2271] The omission of any recognition of departed load responsibility for the remaining net book value and decommissioning costs in the JCCA proposal renders the proposal incomplete and inadequate to ensure no shifting of costs to bundled customers. The absence of any proposal or record in this proceeding addressing the decommissioning aspects of unbundled customers' PCIA obligation renders the proposal incomplete - it must be denied on this basis alone.

2270 D.18-10-019, pp. 91-92.

2271 PG&E Opening Brief, p. 39, and PG&E-18, p. 9-8, lines 20-31.

5.8.4.4 Assuming An Extended Life For A Hydro Facility Is Not A New Commitment That Should Trigger Revintaging

CCA proposes to assign new vintages to 12 of PG&E's hydro facilities based on the year of the GRC in which PG&E presented a depreciation study reflecting an extended life for these hydro facilities. This is the position JCCA took in its testimony and PG&E's rebuttal testimony and Opening Brief (at Section 5.8.3.1) address it fully. In its Opening Brief, JCCA asserts for the first time that the Commission should not approve PG&E's depreciation study without adopting its hydro re-vintaging proposal.[2272] There is absolutely no reason to allow JCCA to hijack a depreciation study addressing depreciation of all of PG&E's assets in support of its UOG revintaging gambit. The Commission should ignore this unfounded, new position because Commission adoption of PG&E's depreciation study is wholly and completely unrelated to UOG vintaging.

JCCA further asserts – and requests that the Commission conclude - that PG&E's proposal to extend the life of any UOG asset in a depreciation study constitutes a new commitment on behalf of bundled customers.[2273] JCCA doesn't indicate what that "new" commitment is and for good reason – extending an assets life for depreciation purposes changes nothing about that asset other than the time frame over which the cost of the asset is recovered. All of the customers for whom the asset was purchased or developed appropriately remain responsible for the ongoing cost to retain and maintain that UOG asset, including depreciation costs.

JCCA's assertion that "only costs committed and reasonably anticipated to serve that load at the time of departure, based on the expected asset life at that time, should be recovered from unbundled customers,"[2274] fails in particular with regard to hydro facilities. As PG&E noted in its rebuttal testimony and Opening Brief, as a practical matter, there is no pre-defined end of life

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2272 JCCA Opening Brief, p. 22.

2273 JCCA Opening Brief, p. 22.

2274 JCCA Opening Brief, p. 22.

for a hydro facility. As evidenced by the fact that we only recently initiated accrual into a hydro decommissioning reserve, PG&E considers the hydro assets to be forever assets – we expect they will continue to be relicensed into the future.[2275] Additionally, PG&E must continue complying with existing license requirements until the Federal Energy Regulatory Commission issues an order on its relicensing or surrender application.[2276] Annual licenses are automatically issued until a new license is issued.[2277]

Most importantly, the ongoing costs to maintain the dams and reservoirs necessary to support hydro facility operations do not change based on who the service provider is for customers in PG&E's service territory. Assigning a new vintage for a resource would effectively allow departed load to avoid paying for the eventual decommissioning of the resources as well. Such a result, exempting CCA customers from responsibility for a hydro facility revenue requirement based on an artificial relicensing date, would be arbitrary and violate the principles of maintaining customer indifference.[2278] Because these resources were procured to serve load that has since departed for CCAs, the principle of customer indifference requires that departed and bundled load customers continue to pay all costs associated with maintaining, operating and decommissioning these resources.

5.8.4.5 Relicensing A Hydro Asset Should Not Trigger Revintaging

When PG&E decides to relicense a hydro facility, it is not making a new commitment, but is extending an existing commitment to maintain the facility's operating license.[2279] As PG&E Witness Doidge testified, "In most cases, when we are licensing a project, we're simply

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2275 Tr. Vol. 11, 2046:2-19, PG&E/Doidge.

2276 16 U.S.C. § 808(a)(1).

2277 Id.

2278 PG&E-18, p. 9-7, lines 27-30.

2279 Tr. Vol. 11, 2024:20-2025:3, PG&E/Doidge.

extending the term of the license, not changing the underlying functionality of the project."[2280] JCCA insists repeatedly, without basis, that PG&E's analysis of whether to relicense its hydro assets focuses only on whether it will benefit PG&E's bundled customers. In service of its argument, JCCA mischaracterizes the testimony of PG&E's witness as an admission that hydro relicensing decisions are made on behalf of bundled customers.[2281] In fact, Ms. Doidge testified that when PG&E considers whether to relicense a hydro asset, its focus is on whether the asset is economic overall, not on whether the megawatts produced are necessary to serve bundled customer load.[2282] Ms. Doidge made a distinction between PG&E's review of its overall portfolio, noting that, long term generation supply is one of the factors that drives PG&E's consideration of its portfolio overall, but when we evaluate an individual project and the alternatives to that project, whether to own and operate, sell or retire, we don't make that decision based on the needs of our bundled customers.[2283]

The fact is, PG&E's decisions to relicense a given hydro asset consider whether the facility is cost-effective and other benefits that positively impact all customers, e.g., local area reliability, local reliability if natural gas access is limited, reliability during PSPS events, voltage support, black-start capability, fulfillment of water rights and public recreational use. The majority of PG&E's hydroelectric fleet provide benefits that positively impact all customers.[2284]

The fact that energy and capacity are the primary benefit of PG&E's hydro assets does not negate the additional benefits to all customers and the Commission should reject JCCA arguments otherwise. Furthermore, the Commission must ignore JCCAs false assertion that unbundled customers payment for resources used to meet PG&E's resource adequacy ("RA")

2280 Tr. Vol. 11, 2024:20- 2025:3, PG&E/Doidge.

2281 JCCA Opening Brief, p. 28.

2282 Tr. Vol. 11, 2033:21-25 and 2034:20-28PG&E/Doidge.

2283 Tr. Vol. 11, 2036:19-2037:10, PG&E/Doidge.

2284 PG&E-18, p. 9-9, lines 3-10.

requirements amounts to a subsidy.[2285] There is no subsidy. PG&E bundled customers "pay" the imputed market costs for the RA associated with UOG and those payments are included as part of the revenues from UOG assets that are included in the PCIA calculation. PG&E customers therefore pay for the full market value of the RA associated with UOG and departed load customers receive their share of the revenues from those payments via the PCIA.

For all of these reasons, the Commission should reject the JCCA UOG revintaging proposals.

5.8.5 Diablo Canyon Retirement Balancing Account

The TURN-PG&E Energy Supply Stipulation between reasonably resolves the disputed issues between PG&E and TURN regarding the Diablo Canyon Retirement Balancing Account (DCRBA) and should be adopted.[2286] No other party addressed the DCRBA.

2285 JCCA Opening Brief, pp. 28-29.

2286 PG&E Opening Brief, p. 631, Appendix E, Section I(B).

6. CUSTOMER AND COMMUNICATIONS (EXHIBIT PG&E-06)

Customer Care and Communications drives PG&E's customer strategy and communications across all functional areas and delivers a broad range of services, products, and support to customers. Customer Care and Communications' goal of providing superior customer experience and hometown service is furthered by key projects addressed in this GRC. These projects include: (1) the Gas Advanced Metering Infrastructure (AMI) Module Replacement project, which will support the collection of daily gas usage data from PG&E's 4.6 million gas meters by proactively replacing the communicating modules on the meters, which are reaching end of life; (2) PG&E's Billing System Upgrade project, which will modernize PG&E's billing system (installed in 2001) to allow for timely rate program design; (3) Customer Engagement projects, such as electric vehicle charging to meet California's climate goals; and (4) non-tariffed products and services. PG&E submitted substantial evidence demonstrating the reasonableness of the forecasts necessary to support these activities and how they are vital to performing core business functions.

6.1 Forecast

PG&E fully addressed issues raised by parties in its Opening Brief.

6.2 Regional Vice Presidents

TURN's proposal to disallow costs of officer compensation and benefits should be denied as these are reasonable costs of service for positions the Commission mandated PG&E to create.

As discussed in PG&E's testimony, in the Plan of Reorganization proceeding, the Commission directed PG&E to hire five Regional Vice Presidents (RVPs).[2287] The Company engaged the five RVPs in 2021. The RVPs live and work in their local communities and are actively engaged in the challenges and opportunities unique to their regions. PG&E's RVPs share direct accountability with our core functional organizations for their region's customer experience, as well as safety and operational performance.

[2287] D.20-05-053, p. 52.; PG&E-06-E, p. 1-A1.

PG&E's TY 2023 expense forecast for the RVPs and their immediate offices is $11.439 million, which consists of $6.064 million for RVP Operational Management and $5.375 for Customer and Communications Operational Management.[2288] PG&E's JCE forecast, which includes adjustments for inflation provided in PG&E's September 2022 Update Testimony, is $6.118 million.[2289] The expense forecast includes work tracked in MWC OM, Operational Management.

TURN recommends a $1.747 million disallowance.[2290] TURN argues that PG&E has not established why customers should fund the five RVPs, and incorrectly asserts that the RVPs will not confer any additional safety benefits to customers. To support this claim, TURN delves into the record of PG&E's Regionalization Proposal (A.20-06-011) to purportedly show that the RVPs are not likely to improve safety,[2291] and again raises issues whether safety metrics should have been included in the Regionalization Plan. TURN neglects to disclose the fact that the Assigned Commissioner determined that safety metrics were out of scope of that proceeding.[2292] TURN is merely rehashing issues that it raised and the Commission considered and rejected in approving PG&E's Regionalization Plan.[2293] More importantly, TURN ignores the fact that the Commission directed PG&E to hire the RVPs.[2294] PG&E addressed these assertions in more detail in Section 6.2 of its Opening Brief.[2295]

2288 PG&E-19-E, p. 1A-2, Table 1A-1, lines 1-3.

2289 PG&E-64, p. 3-4, Table 3A-1, line 164.

2290 TURN Amended Opening Brief, p. 530.

2291 TURN Amended Opening Brief, p. 530.

2292 D.22-06-028, p. 22.

2293 D. 22-06-028, pp. 22-23.

2294 D.20-05-053, p. 52.

2295 PG&E Opening Brief, pp. 633-634, Section 6.2.

6.3 Customer Engagement

Customer Engagement provides support for a variety of program areas including, for example, services to small and medium businesses, Public Safety Power Shutoffs (PSPS) planning and readiness, economic development, distributed generation, and clean energy transportation. PG&E's TY 2023 expense forecast is $101.830 million. PG&E's JCE forecast which is adjusted for inflation is $107.876 million.[2296] Cal Advocates and TURN dispute PG&E's forecast and propose reductions of $9.685 million and $8.944 million, respectively.[2297]

PG&E's TY 2023 capital expenditure forecast is $8.550 million. PG&E's JCE forecast which is adjusted for inflation is $10.347 million.[2298] TURN and Cal Advocates dispute PG&E's forecast and proposes the following reductions:

TABLE 6-1
EV STATION INFRASTRUCTURE: PG&E'S CAPITAL FORECAST AND PARTIES' RECOMMENDED REDUCTIONS ($000s)(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	$2,928	$2,400	$2,300	$8,550	$9,360	$4,650	$5,900
TURN				$(6,250)	$(6,960)	$(2,150)	$(3,300)
Cal Advocates				$(2,300)			
(a) PG&E-19-E, p. 2-16, Table 2-6, line 2; p. 2-4, Table 2-2, line 1.							

Cal Advocates' and TURN's proposed reductions to PG&E's forecasts for the following programs: (1) Non-Tariffed Products and Services; (2) Electric Vehicle Infrastructure Program; and (3) Internal Fleet Program. These issues are addressed below.

6.3.1 Non-Tariffed Products And Services (NTP&S)

PG&E's NTP&S program benefits customers by generating incremental revenues through marketing products and services to third parties (e.g., the short-term use of PG&E

2296 PG&E-64, p. 3-4, Table 3A-1, lines 133-139.

2297 PG&E-19-E, p. 2-15, Table 2-5, line 10; p. 2-3, Table 2-1, line 8. TURN's recommended forecast reduction for MWC EL as shown in PG&E's rebuttal testimony is $(8,800) whereas it is $(8,838) in the JCE. PG&E-19-E, p. 2-3, Table 2-1, line 2; PG&E-64, p. 2-444.

2298 PG&E-64, p. 3-8, Table 3B-1, lines 96-97.

facilities or real property). These products and services use available capacity of PG&E assets, such as distribution poles. Revenue from NTP&S third-party transactions offsets associated expenses (e.g., invoicing, contract administration, payment of vendors, etc.) and the net revenue in excess of NTP&S expenses is credited back to customers on a forecast basis. The net revenue forecast for 2023 from the NTP&S program is $4.772 million,[2299] which requires incurring the forecast expense to generate the forecast revenue. Additionally, customers will benefit in 2023 from the Wireless Tower Licenses Sales credit of $5.887 million.[2300]

TURN asserts that "overall demand for NTP&S revenue forecasted by PG&E in 2023 is significantly less than 2020" and that "[i]n 2023, PG&E forecasts that its NTP&S revenues from Telecom products, including Distribution (Rent), Transmission (Rent), Distribution (NRD Fee), and Transmission (NRD Fee) are expected to drop from $45.6 million in 2020 to $14.7 million in 2023, a $30.9 million decrease."[2301] TURN also asserts that NTP&S services are not profitable for customers.

TURN relies on faulty math to support its incorrect assertions. Specifically, TURN claims to show a decrease in telecom revenue from 2020 to 2023.[2302] TURN errs by including transmission rent and transmission new revenue development (NRD) fees to calculate customer impacts. In doing so, TURN is using the wrong denominator to determine the ratio of revenue to expense. TURN also ignores the substantial increase in demand for NTP&S demonstrated by the 2021 actual results.[2303]

2299 Revenue of $54.623 million includes aggregated 2023 Distribution Revenue for MWC EL NRD Forecast in PG&E-10, WP 16-4 to WP 16-5. Expense of $49.851 million is derived from Table 2-21 for Customer Expense for MWC EL in 2023.

2300 PG&E-19-E, p. 2-8, line 16.

2301 TURN Amended Opening Brief, p. 533.

2302 TURN Amended Opening Brief, p. 533.

2303 PG&E-23-E, Ch. 10, Attachment A (filed Nov. 2, 2022), p. 10-AtchA-8.

TURN wrongly insists on using transmission asset-related revenues to support an argument that *distribution level* assets are not sufficiently profitable to justify increased expense. As PG&E has explained, Federal Energy Regulatory Commission (FERC)-jurisdictional revenues were included in PG&E's workpapers for context only and revenue and expenses relating to FERC-jurisdictional programs are not included in PG&E's 2023 GRC.[2304] Non-tariffed revenues and costs associated with FERC-jurisdictional assets are shared with customers through the FERC Transmission Owner (TO) ratemaking process, not the GRC. Although the revenues are shown in PG&E's Other Operating Revenue workpapers,[2305] the "TT" designation in the workpapers indicates that they are transmission related.[2306] These amounts are therefore not included in the Results of Operations model to calculate the revenue requirement.[2307] Because TURN's equation uses the TO revenues and costs, TURN's benefit calculations are fundamentally wrong.

When correctly calculated, the revenues from CPUC-jurisdictional services and assets (identified with the "D" designation in workpapers), and the CPUC-jurisdictional portion of the SBA Towers Transaction, combined with the requested increase in expense, do not result in a detriment to customers. Using values properly derived solely from CPUC-jurisdictional assets, the net effect is an additional benefit to CPUC customers of $0.2 million. This additional $0.2 million benefit is a result of the increase in revenue for distribution-related new products ($9.6 million)[2308] plus the annual amortized credit from the SBA Towers Transaction ($5.9 million),[2309] *less* the decrease in distribution-related rent and fees from

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2304 Tr. Vol. 7, p. 1296:20-23, PG&E/Guenther.

2305 PG&E-10, WP 16-4 to WP 16-5.

2306 PG&E-19-E, p. 2-9, lines 2-7.

2307 PG&E-19-E, p. 2-7, lines 24-26.

2308 PG&E-10, WP 16-5, line 58 (2023 Forecast – 2020 Forecast).

2309 PG&E-10, WP 16-5, line 59 (2023 Forecast).

2020 ($6.5 million)[2310] and PG&E's 2023 expense forecast increase ($8.8 million).[2311] Thus, CPUC-jurisdictional customers are receiving $0.2 more, not $20 million less, as TURN suggests.[2312]

TURN asserts that NTP&S revenue from telecom products is set to drop by $30.9 million, which TURN argues is attributable to decreases in rents and fees relating to transmission and distribution assets.[2313] TURN's calculation is baseless. PG&E cannot replicate the calculation used to attain this number, and the Commission should disregard it.

6.3.2 The Electric Vehicle Infrastructure Forecast Is Just And Reasonable.

Cal Advocates disputes PG&E's MWC 28 forecast and recommends a $2.3 million reduction for 2023.[2314] Cal Advocates argues that PG&E has not made a showing as to why ratepayers should fund the electric vehicle charging for utility employees. PG&E addressed these arguments in its Opening Brief.[2315]

6.3.3 The Internal Fleet Program Forecast Is Reasonable And Should Be Approved

TURN opposes PG&E's Internal Fleet Program, arguing that the Commission has not previously approved the program and has not conducted a cost-benefit analysis.[2316] TURN ignores that the Commission has previously approved similar activities.[2317] Following PG&E's 2020 GRC, the Internal Fleet Program became a distinct program. The Program's activities are

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2310 PG&E-10, WP 16-4, lines 33 and 35 (2023 Forecast – 2020 Forecast).

2311 PG&E-06-E, WP 2-37. PG&E forecasts an increase of $8.8 million for 2023 relative to 2020 recorded costs for NTP&S.

2312 TURN Amended Opening Brief, p. 534.

2313 TURN Amended Opening Brief, p. 533.

2314 Cal Advocates' Opening Brief, p. 330.

2315 PG&E Opening Brief, pp. 638-639, Section 6.3.2.

2316 TURN-15, p. 8, lines 16-17.

2317 D.20-12-005, p. 401, COL 66.

consistent with PG&E's commitment to reach net zero greenhouse gas emissions by 2040 and to electrify its vehicle fleet in alignment with the Advanced Clean Fleets Rule (currently in development at the California Air Resources Board (CARB) and expected to be voted on by CARB in early 2023).[2318]

6.4 Pricing Products And Income Qualified Programs

No party disputed PG&E's Pricing Products and Income Qualified Programs forecasts. Please see PG&E's Opening Brief Section 6.4.

6.5 Contact Centers, Customer Technology, And Digital Strategy

No party disputed PG&E's Contact Centers, Customer Technology, and Digital Strategy forecasts. Please see PG&E's Opening Brief Section 6.5.

6.6 Customer Service Offices

TURN recommends a reduction of $11.195 million for PG&E's 2023 Customer Service Office (CSO) expense forecast, based on 2021 recorded costs. The CSOs closed in 2020 due to COVID-19 and remain closed. Cost information from 2021 accordingly does not reflect the costs that PG&E would incur to operate the CSOs if they are re-opened. PG&E's 2023 expense forecast supports the staffing levels needed to provide effective customer service and support if its proposal in A.22-04-016 (proposing to permanently close all CSOs) is denied. If the Commission approves PG&E's request to close its 65 CSOs, the refund mechanism to which TURN and other parties agreed upon that was submitted as a Memorandum of Understanding in the CSO Application proceeding requires PG&E to return cost savings to customers. PG&E fully addressed TURN's assertions in its Opening Brief.[2319]

2318 CA Air Resource Board's Advanced Clean Fleets Proposed Draft Regulation Language: High Priority and Federal Fleet Requirements (May 2, 2022), <https://ww2.arb.ca.gov/sites/default/files/2022-04/220502drafthpf_ADA.pdf> (as of Dec. 3, 2022).

2319 PG&E Opening Brief, pp. 641-643, Section 6.6.

6.7 Billing, Revenue And Credit

No party disputed PG&E's Billing Revenue and Credit forecasts. Please see PG&E's Opening Brief Section 6.7.

6.8 Metering Services And Engineering

While Metering Services and Engineering's forecast were largely undisputed, Cal Advocates and TURN propose to remove all costs associated with PG&E's Community Rebuild Program from PG&E's forecasts and require PG&E to instead seek approval of these amounts in arrears through a Catastrophic Event Memorandum Account (CEMA) application.[2320] PG&E does not agree with this proposal for the reasons discussed in Section 4.23 of PG&E's Opening Brief and this Reply Brief regarding the Community Rebuild Program.

6.9 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, audit; and customer and employee privacy. PG&E's TY 2023 expense forecast is $21.352 million. PG&E's JCE forecast, which is adjusted for inflation, is $21.864 million. Expense work is tracked in two MWCs, one of which, MWC EZ, Manage Various Customer Care Processes, is uncontested. See Appendix A.

The forecast for the contested MWC (i.e., MWC OM) is $5.375 million which includes labor and employee-related costs to provide supervision and management support, as well as costs for administrative staff working for the Supervisors and Managers. TURN recommends a reduction of $1.9 million to PG&E's forecast.

TURN argues that PG&E should not recover the costs to compensate its Customer Care officers because PG&E is voluntarily not recovering it currently.[2321] While PG&E elected not to seek officer compensation in the 2020 GRC, in did not waive its right to recover officer

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2320 TURN Amended Opening Brief, p. 586; Cal Advocates Opening Brief, p. 321.

2321 TURN Amended Opening Brief, p. 540.

compensation in future GRCs. Officer compensation is a reasonable cost of service. As TURN knows, the Commission allows utilities to recover the costs of utility officers, other than those officers who are defined by Rule 240.3b-7 of the Securities Exchange Act.[2322] PG&E addressed these assertions in its Opening Brief.[2323] TURN's opposition to compensation for Customer Care officers should be denied.

6.10 Gas AMI Module Replacement

PG&E's Gas AMI Module Replacement Project is for the accelerated replacement of legacy Gas Modules (modules), which are reaching end of life (EOL) over the next several years. PG&E notified the Commission and parties in its 2020 GRC that the modules had begun to fail.[2324] To date, PG&E has been replacing modules as they fail as part of a corrective maintenance program. PG&E has performed rigorous analyses to determine the least-cost option to replace these modules and now proposes a proactive Replacement Project as part of the system's asset life cycle management.[2325] The modules are communications devices attached to gas meters that automatically communicate customer gas usage readings to PG&E to enable automated, remote gas meter readings, which PG&E then utilizes to bill the Company's over four million gas customers. These module replacements are essential to providing utility service and require replacement.

PG&E's TY 2023 expense forecast as reflected in rebuttal testimony is $9.437 million. PG&E's JCE forecast, which is adjusted for inflation, is $9.715 million.[2326]

2322 *See* D.21-08-036, pp. 418-419.

2323 PG&E Opening Brief, pp. 645-646, Section 6.9.

2324 A.18-12-009, Hearing Exhibit (HE)-91: Exhibit (PG&E-6), p. 6-16 to p. 6-17, Meter Mesh Technology Life Cycle Risk.

2325 PG&E-19-E, p. 9-18, lines 1-27.

2326 PG&E-64, p. 3-4, Table 3A-1, lines 157-160.

PG&E capital expenditures forecast as reflected in rebuttal testimony is $46.063 million in 2021, $54.751 million in 2022, $94.988 million in 2023, $141.626 million in 2024, $133.560 million in 2025, and $110.310 million in 2026. Capital expenditures forecast in the JCE adjusted for inflation are $47.469 million in 2021, $63.573 million in 2022, $114.948 million in 2023, $171.631 million in 2024, $159.768 million in 2025, and $130.273 million in 2026.[2327]

Cal Advocates, TURN, and AARP dispute PG&E's 2023 expense forecast and propose reductions of $2 million, $9.437, and $9.437, respectively.[2328] Cal Advocates, TURN, and AARP also dispute PG&E's capital forecast and propose the following reductions.

TABLE 6-2
GAS AMI MODULE REPLACEMENT: PG&E'S CAPITAL FORECAST AND PARTIES' RECOMMENDED REDUCTIONS ($000s)(a)

Party	2020 Rec.	2021	2022	2023	2024	2025	2026
PG&E	$-	$46,063	$54,751	$94,988	$141,626	$133,560	$110,310
Cal Advocates				$(71,678)			
TURN				$(94,988)	$(141,626)	$(133,560)	$(110,310)
AARP				$(93,238)	$(141,551)	$(133,485)	$(110,235)
	(a) PG&E-19-E, p. 9-29, Table 9-5, line 3; p. 9-6, Table 9-2, line 3; p. 9-7, Table 9-2, line 6.						

PG&E responds below to these parties' positions. As discussed below: (1) multiple analyses demonstrate that proactive replacement is the least-cost option for replacing the modules; (2) PG&E has acted prudently in its management of Gas AMI system to address the failures of the modules and the end-of-life replacement planning; (3) PG&E is holding its module supplier accountable; (4) it is inappropriate to use 2021 recorded costs to forecast the project's costs; and (5) PG&E's rate of return for the existing and new modules should not be reduced.

2327 PG&E-67, WP-4; PG&E-06-E, p. 9-16, lines 19-25, MWC 2F.

2328 PG&E-19-E, p. 9-28, Table 9-4, line 5; p. 9-5, Table 9-1, line 5.

AARP also argues that there is variation in PG&E's projected costs and benefits and thus the AMI Gas Module Replacement project may not be cost-effective.[2329] PG&E fully addressed this assertion in its Opening Brief and does not further address it here.[2330]

6.10.1 TURN Conflates PG&E's Distinct Cost Analyses

PG&E's Gas AMI Module Replacement Project provides for the proactive replacement of legacy gas modules to more cost effectively replace these modules. It is less expensive to proactively replace the modules than to wait for the modules to eventually fail, and then replace each individually. Whereas the latter approach requires numerous one-off truck rolls, a proactive replacement plan offers economies of scale and shorter travel times, and limits billing gaps for affected customers.[2331]

TURN asserts that incremental funding for corrective maintenance (i.e., without the proactive replacement program) "does not square" with PG&E's showing.[2332] This is incorrect. As PG&E demonstrated in its opening and rebuttal testimony, an economic analysis over a 15-year study period demonstrates that the net present value (NPV) of proactively replacing the Gas AMI Modules is a net cost of $936 million (of capital and expense), compared to a net cost of $963 million if PG&E continues replacing individual modules as they fail.[2333] PG&E estimates that unless it proactively replaces these failing modules, costs will increase by approximately $400 million in capital[2334] above its maintenance forecast during the 2023-2026 period. Proactive replacement of the remaining legacy modules will reduce subsequent corrective module maintenance costs, resulting in long-term savings for customers.

2329 AARP-01, p. 55, lines 9-17.

2330 PG&E Opening Brief, pp. 654-656, Section 6.10.3.

2331 PG&E-06-E, p. 9-9, lines 10-22; PG&E-19-E, p. 9-22, lines 3-5.

2332 TURN Amended Opening Brief, p. 543.

2333 PG&E-06-E, p. 9-6, Table 9-1; PG&E-19-E, WP 9-2.

2334 PG&E-19-E, p. 9-24, lines 5-19.

PG&E's current corrective maintenance volumes and forecasts are based on an assumption that PG&E would initiate a mass proactive replacement project in 2023. If PG&E's proposal is denied, the Commission should authorize a commensurate $400 million increase in corrective maintenance work above the amounts for the maintenance program currently forecasted in the 2023-2026 GRC period[2335]

6.10.2 PG&E Has Provided A Sufficient Record Of Its Prudency In Its Dealings With Its Supplier

PG&E installed its Gas AMI infrastructure from 2006 to 2013, making PG&E one of the early adopters of this technology within the energy industry. The typical warranty for Gas Modules at that time, to PG&E's knowledge, was one to three years.[2336] Nonetheless, PG&E reached agreement with its supplier to warranty its modules on a pro-rata remaining-life basis for 20 years.[2337] For example, if a module failed after eight years, PG&E would be entitled to the value of 12 additional years.

PG&E has engaged in confidential negotiations with its supplier, including a mediation, to address the manufacturer's liability under the warranty and provided the discovery responses to the fullest extent possible while respecting confidentiality obligations to the supplier.

TURN argues that PG&E has not been forthcoming regarding the details of PG&E's negotiations and mediation with its supplier, and for this reason it questions the reasonableness of the Company's actions.[2338] This assertion is directly at odds with PG&E's extensive discovery responses on this topic, including the original supplier agreement and warranty, as well as the settlement that PG&E reached with its supplier once the full scale of the premature

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2335 PG&E-19-E, p. 9-24, lines 5-19; PG&E-19-E, WP 9-1, line 50.

2336 PG&E-19-E, p. 9-17, lines 3-7.

2337 PG&E-19-E, p. 9-17, lines 2-15.

2338 TURN Amended Opening Brief, Confidential Appendix D, p. 3.

module failure issue became known.[2339] In addition, PG&E provided TURN and other parties with updated failure rate models and detailed unit costs that make up PG&E's forecast.[2340] TURN also sought, and PG&E produced, information that details the nature of the modules' premature failure and the modules' reduced lifespans, justifying PG&E's accelerated EOL replacement plans.[2341]

6.10.3 PG&E Has Held Its Supplier Accountable In The Course Of Exercising Sound Judgment In Its Project Management

As discussed above, the evidence PG&E produced in response to TURN's data requests shows with specificity the factors that led to premature module failures, and that these factors were beyond PG&E's control.[2342] TURN was provided this supplier communication on August 12, 2022.[2343] On April 27, 2022, in response to a TURN data request, PG&E indicated that the supplier had disagreed with amounts owed under the warranty but, as discussed below, the matter has resolved to PG&E's satisfaction[2344] PG&E believed the supplier's contention was without a factual basis. Yet solely based on a single unsupported statement by PG&E's supplier, TURN requests the Commission to completely disallow PG&E's proactive replacement costs.[2345] In the interest of avoiding a confidential filing and providing a public record, PG&E does not discuss this evidence in detail here.

2339 TURN 406-C, PG&E Response to Data Request TURN 240-Q012, dated 8/13/22; PG&E Response to Data Request TURN 185-Q004, dated 4/27/22; PG&E Response to Data Request TURN 149-Q004, dated 3/18/22. TURN 407, PG&E Response to Data Request TURN 185-Q008, dated 4/13/22.

2340 TURN 408, PG&E Response to Data Request AARP 003-Q027, dated 3/1/22.

2341 TURN-406-C, PG&E Response to Data Request TURN 240-Q012, dated 8/12/22, and Atch01CONF (Aclara Presentation to PG&E, April 30, 2015).

2342 TURN 406-C, TURN 240-Q012Atch01CONF, p. 23.

2343 TURN 406-C, PG&E Response to Data Request TURN 240-Q012, dated 8/12/22, and Atch01CONF.

2344 TURN 406-C, PG&E Response to Data Request TURN 185-Q004c, dated 4/27/22.

2345 TURN Amended Opening Brief, Confidential Appendix D, pp. 2-3.

TURN chose to ignore the issue during the evidentiary hearings and instead focus its questioning for the panel of three Gas AMI witnesses on PG&E's unrelated Revenue Assurance forecast. TURN declined to avail itself of the opportunity at hearing for a confidential session to explore this issue.

PG&E has held its supplier accountable. In 2018, PG&E secured $8 million in cash consideration for modules that had failed through the end of 2016,[2346] and discounts against the purchase of future modules needed for corrective maintenance, as well as full replacement of extended range models that had a particularly early EOL.[2347] PG&E has actively pursued a remedy from the supplier to offset the costs of the replacement program. And PG&E has recently achieved a settlement in principle with its supplier since filing its Opening Brief, which the parties now are working to document.

The settlement in principle does not require a change to PG&E's forecast as PG&E already anticipated a settlement and resolution of this issue with its supplier. PG&E's forecast already assumed the matter would be resolved in PG&E's favor and that PG&E would receive warranty credits. PG&E provided a warranty credit forecast[2348] and the recently achieved agreement in principle is consistent with that forecast.

The Commission previously has acknowledged that "evaluating the performance of a utility in negotiations is extremely difficult" owing to the difficulty in establishing a baseline for comparison and a "nearly an infinite number of proposals and combinations of proposals that could be considered and… a range of outcomes that are reasonable and prudent."[2349] Successful resolutions to negotiations usually "involve a subjective balancing of interests, a compromising of objectives, and much creativity in developing a solution that satisfies all

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2346 PG&E-06-E, WP 9-12, Table 9-12, line 2 ("2018" column).

2347 PG&E-19-E, p. 9-19, lines 5-7.

2348 D.89-02-074.

2349 D.89-02-074, p. 14.

parties."[2350] PG&E has achieved this balancing of interests here. This settlement in principle protects PG&E's customers by ensuring its supplier will recompense early module failure without the risk and expense of litigation.

The Commission, in evaluating negotiations, has "first examined the goals that the utility hoped to achieve in the negotiations" and "whether that goal was reasonable," and "then compared the actual outcome with the goal."[2351] PG&E was reasonable in seeking a negotiated resolution, not only to hold its supplier accountable for the modules' premature failure and associated litigation risk, but to ensure the ready access to an important product for its billing processes. PG&E's agreement with its supplier achieves these objectives.

PG&E acknowledges that it has the burden to prove the reasonableness of its actions in this case. Contrary to TURN's assertion, the fact that the supplier initially disputed PG&E's warranty assessment does not merit a disallowance of the project's costs.

Regardless, the substance of PG&E's business communications with its supplier that TURN cites as its sole evidence that PG&E was at fault for the premature module failures is hearsay. The truth of their contents is disputed and cannot support a finding of fact by the Commission. "'Hearsay evidence' is evidence of a statement that was made other than by a witness while testifying at the hearing and that is offered to prove the truth of the matter stated."[2352] As a basis for its disallowance argument, TURN offers, for the truth of the matter asserted, the statement of a third-party who was not available for cross-examination.[2353] While hearsay evidence is not per se inadmissible in Commission proceedings, "hearsay evidence may not serve as the sole factual basis for the Commission's finding…."[2354] TURN provides no

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2350 D.89-02-074, p. 14.

2351 D.89-02-074, p. 14.

2352 Evidence Code § 1200(a).

2353 TURN 406-C, PG&E Response to TURN Data Request 185-Q004c, dated 4/27/22.

2354 *The Util. Reform Network v. Pub. Utils. Comm'n*., 223 Cal. App. 4th 945, 962.

other evidence other than this uncorroborated hearsay. The Commission may not base a disallowance or finding of imprudent management on this evidence alone.

In support of a disallowance, TURN cites to D.16-06-056,[2355] which provides that a "disallowance is warranted when the forecast work is necessary because: (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."[2356] While the burden of proof rests with PG&E, the Commission has held that the standard of proof is that of a preponderance of evidence. 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.'"[2357]

While PG&E bears the ultimate burden to prove the reasonableness of its request, 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."[2358] TURN has not met this burden. Through its opening and rebuttal testimony PG&E has demonstrated the reasonableness of its actions in deploying gas AMI technology and in addressing the premature failure of the gas modules from the time the failure became known until the present. Notwithstanding the fact that TURN's evidence is hearsay, it is also insufficient to show that PG&E made a clear and identifiable failure or error. In actuality, the record based on documents PG&E produced to TURN in discovery shows the contrary.[2359] TURN's arguments are merely speculation.

2355 TURN Amended Opening Brief, p. 542.

2356 D.16-06-056, pp. 22-23.

2357 D.16-06-056, p. 23.

2358 D.21-08-036, p. 10.

2359 TURN 406-C, TURN 240-Q012Atch01CONF, p. 23.

The Commission judges the reasonableness of a particular management action depending on "what the utility knew or should have known at the time that the managerial decision was made, not how the decision holds up in light of future developments."[2360] In spite of PG&E's extensive scrutiny, quality assurance, and due diligence through its AMI deployment, a certain measure of unforeseen risk is inherent in any project of such a scale and ambition. The Commission acknowledged this in its decision approving the program, noting that "[a]lthough PG&E expects the system to remain in service for 20 years, only time will tell whether there will be significant unforeseen developments—good or bad–that may lead to an earlier or later replacement of the AMI system."[2361]

TURN knows the nature and extent of PG&E's prudent conduct and the factors contributing to the premature module failures,[2362] yet makes no mention of this undisputed evidence in its Opening Brief.

In judging the reasonableness of PG&E's actions, the Commission should consider that PG&E adopted and deployed AMI at the Commission's urging very early on.[2363] As a result, PG&E stood up a large and comprehensive deployment program that included visits to manufacturing facilities, product testing, and quality assurance.[2364] Since the discovery of the Modules' accelerated EOL, PG&E has closely and prudently managed the response to ensure customers are protected.[2365] PG&E's proactive replacement program is part of its efforts to find a least-cost solution and do so in a way that provides a positive customer experience.

2360 D.02-08-064, p. 5.

2361 D.06-07-027, pp. 27-28.

2362 TURN 406-C.

2363 D.11-05-018, p. 42: "The Commission encouraged the electric utilities, including PG&E, to consider and implement AMI. PG&E responded with an initial AMI proposal in June 2005 (A.05-06-028) and a revised Proposal in December 2007 (A.07-12-009)."

2364 PG&E-19-E, p. 9-14 top. 9-17.

2365 PG&E-19-E, p. 9-18 top. 9-19.

Finally, since the filing of PG&E's Opening Brief in this proceeding, a resolution in principle has been reached through mediation with the supplier, with the parties currently working to document the agreement. This is further evidence of PG&E's diligence and reasonable management of a critical and complex project.

6.10.4 PG&E's 2021 Recorded Costs Are Not An Appropriate Basis To Forecast Costs

Cal Advocates asserts that PG&E's capital expenditures for the Gas AMI module replacement have costs included in rates and should be accounted for in this GRC.[2366] Cal Advocates recommends that the Commission adopt PG&E's 2021 adjusted-recorded \$21.6 million amount as the basis for 2021-2023 capital expenditures forecast. Cal Advocates' recommendation ignores the fact that the Gas AMI Module Replacement Project is a discrete project set to begin in 2023. The 2021 recorded costs are not an appropriate, sound, or logical basis to determine adequate funding for a new program. The replacement project (as a least cost option to remediate prematurely failing modules) is based on a forecast of modules expected to reach EOL and the commensurate number of new modules needed to replace them.

Cal Advocates argues that PG&E has underspent prior GRC funding and recommends that 2020 GRC funds be applied towards work that will be conducted in the 2023 GRC period.[2367] Yet Cal Advocates does not use the 2020 imputed adopted amounts for MWC 74 to calculate this purported underspend. Instead, Cal Advocates relies on PG&E's forecast amounts for 2021 from this 2023 GRC,[2368] which have been updated based on refreshed module failure

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2366 Cal Advocates' Opening Brief, p. 337.

2367 Cal Advocates' Opening Brief, p. 338.

2368 PG&E-06-E, p. 9-18, Table 9-4.

data and expected work. PG&E's actuals for MWC 74 in 2021 and 2022[2369] do not show any underspend compared with the imputed adopted amounts from its 2020 GRC.[2370] [2371] As such, Cal Advocates' recommendation should be rejected.

6.10.5 PG&E Should Earn A Full Rate Of Return On Early Module Retirements

Costs for the Gas AMI Proactive Replacement Program are reasonable and necessary to provide reliable utility service. Since the deployment of its Gas AMI program, PG&E has exercised prudent management. The proactive replacement project for which PG&E submits in this GRC is the least cost approach to ensure the proper functioning of an essential billing function and provide excellent customer service. TURN suggests that the Commission should disallow PG&E's costs for its prudently incurred gas AMI program.[2372] Cal Advocates recommends that shareholders pay two-thirds of the forecast capital costs associated with the replacement of defective gas AMI modules, or about $388 million over the period 2021-2026.[2373] These recommendations are at odds with longstanding regulatory principles holding that a utility should be allowed a reasonable opportunity to earn a fair return when the utility's conduct has been prudent and reasonable.[2374]

2369 PG&E-64, p. 3-14 to p. 3-16, Table 3B-3. Please see lines 47, 103, and 106 for the combined 2021 actuals for MWC 74. In A.18-12-009, PG&E's 2020 GRC, Field Metering (PG&E-4, Ch. 8, in the 2023 GRC) and Metering Services & Engineering (PG&E-6, Ch. 7 in the 2023 GRC) were both part of Customer Care's Metering Chapter (Exhibit 6, Ch. 6, in the 2020 GRC) while the Gas AMI Module Proactive Replacement Project did not exist at that time. However, Gas Meter and Gas Module maintenance were included in the Company's 2020 GRC and in forecasts for MWC 74.

2370 TURN 608; A.18-12-009, HE-92: Exhibit (PG&E-6), WP 6-3, Table 6-3.

2371 D.20-12-005. p. 186.

2372 TURN Amended Opening Brief, p. 541.

2373 CALPA-05, p. 14, lines 13-17.

2374 *See* D.00-02-046, p. 2: ("We have approached our responsibilities in this case with the intention that PG&E receive a level of revenue for its monopoly distribution services that will assure its customers safe, reliable and responsive service under conditions of prudent management, while assuring PG&E's ability to earn its authorized rate of return, again assuming prudent and effective management.").

These recommendations would essentially punish the utility for equipment failure due to a manufacturing defect despite undisputed evidence that the utility acted prudently and reasonably. As discussed above, in PG&E's Opening Brief,[2375] and testimony,[2376] PG&E has administered its Gas AMI Program prudently and diligently, from its initial deployment of AMI technology, the detection and monitoring of the modules' premature failures, and mitigation, including holding its supplier accountable.

When utilities are penalized for operational risk, for making an otherwise prudent decision, it creates mismatched incentives for adopting new technologies and the inherent operational risk that attends them. The risk utilities would bear, should the Commission reduce PG&E's rate of return on replaced modules, is an asymmetric risk. PG&E's shareholders do not get compensated if assets last longer than their expected life. That benefit is conferred on customers. As such, customers should bear the risk of any required premature retirement under the regulatory compact. Ratepayers benefit when utilities take risks to adopt new technologies, and Commission policy should acknowledge the operational uncertainties in even the most prudently run projects. PG&E has acted prudently, as demonstrated by the extensive record here, and should not be disincentivized from continuing pursuit of new technologies for the benefit of its customers and California.

PG&E further addressed these assertions in its Opening Brief.[2377]

2375 PG&E Opening Brief, pp. 649-654, Section 6.10.2.

2376 PG&E-06-E, Ch. 9; PG&E-19-E, Ch. 9.

2377 PG&E Opening Brief, pp. 656-658, Section 6.10.4.

6.11 Customer Care Technology Projects

Cal Advocates recommends a reduction to PG&E's expense forecast of $8.446 million. Cal Advocates asserts that PG&E's MWC JV forecast for 2023 is overstated because it includes costs already embedded in rates. PG&E addressed these assertions in its Opening Brief.[2378]

TURN recommends a reduction to PG&E's expense forecast of $2.6 million. TURN also recommends capital reductions of $48.3 million in 2023 and $44.2 million in 2024 for MWC 2F. TURN recommends that PG&E remove the Billing System Upgrade Project from this GRC and file a separate application.

In response to these proposed reductions, below we discuss how: (1) the evidence supports PG&E's billing system upgrade and comparisons with the other IOUs' system upgrade showings are not appropriate; (2) the project will not result in stranded assets, and (3) the billing system upgrade is critical to support California's changing rate and regulatory landscape.

6.11.1 PG&E Has Met Its Evidentiary Burden And Comparisons With Other Utility System Upgrades Are Inappropriate

TURN argues that PG&E's showing is deficient, and points selectively to testimony from SCE and SDG&E in an attempt to compare apples-to-oranges.[2379] Even though PG&E's Billing System Upgrade project is not of the same scale, either in cost or functionality, TURN's fundamental premise is flawed. In rate case proceedings, the burden of proof falls to the utility applicant to show by a preponderance of the evidence that its request is reasonable.[2380] The Commission must then judge if the utility has met that burden. SCE and SDG&E's submissions are not relevant to whether PG&E has met its burden. At issue here is PG&E's showing, and PG&E's showing alone.

2378 PG&E Opening Brief, pp. 661-662, Section 6.11.2.

2379 TURN Amended Opening Brief, pp. 548-552.

2380 D.21-08-036, p. 9.

PG&E has met its burden, providing ample support for the Billing System Upgrade project in testimony and workpapers. For example, through its Project Estimating Tool (PET), PG&E's primary tool to document forecast assumptions and provide cost estimates for IT programs and projects.[2381] [2382] Assumptions including, but not limited to, project size, complexity, user, and customer impact, underly the PET's outputs.[2383] PG&E addresses the sufficiency of its showing in section 6.11.1 of its Opening Brief.[2384]

Through its opening and rebuttal testimony, as well as through discovery, PG&E has demonstrated the reasonableness of its forecasts and the urgent need for a new billing system in order to effectively respond to the growing number of rate programs needed to address California's climate policy goals. If the Commission desires regular updates to the project, PG&E can provide annual submissions or status reports that describe refinements to the schedule, forecast, and project phases for the Billing System Upgrade, inclusive of cloud-based activities within the various phases.

6.11.2 The Billing System Upgrade Is Essential To Responsive Rate Change

What SCE, SDG&E, and PG&E's billing system projects do have in common is a critical urgency to replace highly customized, obsolete, and archaic billing systems. These attributes, as detailed in our testimony and opening brief, cause the system to be a drag on the Company's ability to meet the challenge of modern rate design.[2385] As California seeks to address the cataclysmic effects of climate change and chart a course toward a greener future, PG&E must be prepared to implement new and complex rate programs. The Billing System Upgrade Project is

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2381 The PET is described in more detail in Exhibit PG&E-07, p. 8-64, line 4 to p. 8-66, line 24.

2382 PG&E-19-E, Ch. 10, Attachment A.

2383 PG&E-19-E, p. 10-11, lines 24-27.

2384 PG&E Opening Brief, pp. 660-661, Section 6.11.1.

2385 PG&E-06-E; p. 10-9 to p. 10-14; PG&E-19-E, p. 10-14 to p. 10-18; PG&E Opening Brief, pp. 663-666, Section 6.11.4.

essential to that effort. PG&E respectfully requests the Commission adopt its forecasts and reject TURN's proposal to resubmit its request and consequently delay this vital project.

6.11.3 The Billing System Upgrade Will Not Result In Stranded Assets

Cal Advocates[2386] and TURN[2387] argue that upgrades to the existing billing system may result in stranded assets, where upgrades to the existing billing system would no longer be functional, but the remaining net book value would remain in rate base. The Commission should reject such assertions. As PG&E has shown, the Billing System Upgrade is a distinct project, and its associated costs are not duplicative of the existing billing system. The current billing system will continue to provide core customer service and billing functionalities until the new system can be deployed and stabilized, and will be retired upon reaching its approved service life under vintage retirement.

There is no dispute the costs in question for the existing system were prudently incurred. Even as the upgrade project begins, PG&E has a responsibility to maintain and operate its current billing system. Billing is an essential business function for any utility and PG&E's billing system provides support and functionality for many related services, as well as implementation of new rate programs. The current billing system must be sustained to ensure a successful transition and cut over once the new system is in place.

To that end, PG&E must build concurrent rate programs to ensure continuity of billing during the cut over. Upgrades made to the existing system will be useful, as the same rate configuration steps will be required in the new system, albeit incorporated into a modular framework.

Even if the current system were no longer operational, given the Commission authorized a five-year average service life of software assets in PG&E's 2020 GRC, the current system

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2386 Cal Advocates Opening Brief, pp. 341-343.

2387 TURN Amended Opening Brief, pp. 552-553.

assets would likely no longer remain in rate base. Furthermore, PG&E vintage retires[2388] its software assets. As such, all software account assets are retired once they reach their authorized average service life, regardless of the actual retirement.

6.12 Communications

No party disputed PG&E's Communications forecasts. Please see PG&E's Opening Brief Section 6.12.

6.13 Customer And Communications Ratemaking

The balancing accounts and memorandum accounts in Exhibit PG&E-06 are uncontested.

2388 PG&E-10, Ch. 10, p. 10-12, lines 18-23.

7. SHARED SERVICES AND INFORMATION TECHNOLOGY (EXHIBIT PG&E-07)

7.1 Forecast

PG&E's TY 2023 opening expense forecast for Shared Services and Information Technology as reflected in rebuttal testimony is $744.036 million. PG&E's TY 2023 forecast as reflected in the Joint Comparison Exhibit or JCE (Exhibit PG&E-64), which includes the September 2022 updated escalation and all post-February 28, 2022 errata and concessions, is $790.110 million,[2389] of which, approximately $133.159 million, is undisputed.[2390] Following hearings, Cal Advocates, TURN, and PG&E collaboratively resolved disputed issues relating to the Enterprise Data Management (EDM) and Information Technology (IT) forecasts and successfully reached a stipulation.[2391] As a result, PG&E's stipulated forecast for Shared Services and Information Technology is $702.036 million.

PG&E's expense forecast for companywide expenses as reflected in opening testimony is $154.509 million[2392] of which approximately $51.043 million is undisputed.[2393] PG&E's TY 2023 forecast in the JCE is $156.420 million.[2394]

PG&E's opening capital expenditures forecast as reflected in rebuttal testimony is $531.425 million in 2021, $499.064 million in 2022, and $1,473.117 million in 2023, $628.014 million in 2024, $689.630 million in 2025, and $758.331 million in 2026. PG&E's capital

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2389 PG&E-64, p. 3-5, Table 3A-1, Total Exhibit (PG&E-7).

2390 PG&E Opening Brief, Appendix A, p. A-16, line 303.

2391 PG&E Opening Brief, Appendix F.

2392 PG&E Opening Brief, p. 670, and PG&E-20-E, p. 1A-4, Table 1A-1, line 23.

2393 PG&E Opening Brief, Appendix A, p. A-27, line 5, mistakenly showed only $3.595 million of the total uncontested amount. The uncontested amounts listed mistakenly omitted initiatives in the Worker's Compensation program. Table 7-1, p. 670 of PG&E's Opening Brief shows the correct PG&E forecast of $154.509 million and the correct Cal Advocates contested amount of $103.466 million. The correct uncontested amount is $51.043 million ($154.509 million less $103.466 million equals $51.043 million).

2394 PG&E Opening Brief, p. 670, and PG&E-64, p. 3-19, Table 3C-1, lines 32-39.

expenditures forecast as reflected in the JCE is $547.643 million in 2021, $579.477 million in 2022, $1,595.232 million in 2023, $761.068, million in 2024, $824.953 million in 2025, and $895.569 million in 2026.[2395] Approximately $94 million of PG&E's 2023 capital forecast is undisputed.[2396] Following hearings, Cal Advocates, TURN, and PG&E collaboratively resolved disputed issues relating to the Enterprise Data Management (EDM) and Information Technology (IT) forecasts and successfully reached a stipulation.[2397] As a result, PG&E's stipulated forecast for Shared Services and Information Technology is $531.425 million in 2021, $499.064 million in 2022, and $1,467.117 million in 2023, $622.014 million in 2024, $683.630 million in 2025, and $752.331 million in 2026.

The expense and capital forecasts for Sourcing, Land and Environmental Management, Cyber and Corporate Security, and Geosciences are undisputed.[2398]

7.2 Enterprise Health And Safety/Occupational Health

7.2.1 PG&E's Expense And Capital Forecast

PG&E's expense forecast for Occupational Health, companywide expenses, as reflected in rebuttal testimony is $154.509 million.[2399] PG&E's TY 2023 forecast in the JCE is $156.420 million.[2400] Cal Advocates recommends a reduction of $46.049 million to PG&E's Occupational Health companywide expense forecast.[2401] Cal Advocates opposes PG&E's forecasts for Occupational Health companywide expenses for the following programs: (1)

2395 PG&E Opening Brief, p. 668, and PG&E-67, WP-4, Exhibit 7 Total.

2396 PG&E Opening Brief, Appendix A, p. A-25, line 146.

2397 PG&E Opening Brief, Appendix F.

2398 Cal Advocates' Opening Brief, pp. 360-361 and CALPA-10, p. 3, Table 10-1.

2399 PG&E-20-E, p. 1A-4, Table 1A-1, line 23.

2400 PG&E-64, p. 3-19, Table 3C-1, lines 32-39.

2401 PG&E-20-E, p. 1A-4, Table 1A-1, line 23. Cal Advocates' recommended reduction is shown as $47.029 million. PG&E agreed to remove the Substance Abuse Intervention forecast for $0.979 million (line 22). Cal Advocates' adjusted recommendation, excluding the Substance Abuse Intervention Program, is $46.049 million (calculated as: $47.029 - $0.979 = $46.049).

Transitional Light Duty Payroll; (2) Voluntary Plan and Third-Party Disability Management (LTD/STD Pay As You Go); (3) Wellness Programs; (4) Employee Assistance Programs; and (5) Mental Health Services.[2402]

7.2.2 Transitional Light-Duty Payroll

Cal Advocates' Opening Brief reiterates its position as set forth in opening testimony, but fails to refute or even reference PG&E's rebuttal testimony.[2403]

The Transitional Light-Duty Payroll program allows PG&E employees to return to work in a transitional or light capacity,[2404] and is forecast to cost $5.610 million.[2405] Cal Advocates recommends $5.1 million based on an unweighted five-year average. Conversely, PG&E's forecast is based on the 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.[2406] The use of this actuarial analysis is preferable to Cal Advocates' unsupported approach, and is the method most traditionally used in the industry for this type of calculation.[2407]

Willis Towers Watson used a weighted average of the 2015-2019 recorded data, giving the most weight to 2019 and the least to 2015. Cal Advocates, conversely, calculates the average of 2016-2020 Transitional Light Duty Payroll costs without accounting for labor escalation or adjusted headcount. PG&E's methodology is rational, consistent with the record, and superior to Cal Advocates'. PG&E's forecast should be adopted.

2402 Cal Advocates also disputes PG&E's forecast for Long-Term Disability Trust Contributions. This issue is discussed with the Retiree Medical and Retiree Life Insurance Trust Contributions in Section 8.5.

2403 Cal Advocates Opening Brief, p. 345.

2404 PG&E-07, p. 1A-11, lines 10-12.

2405 PG&E-20-E, p. 1A-4, Table 1A-1, line 12.

2406 PG&E-07, p. 1A-12, lines 15-23, and PG&E-07, WP 1A-56 to WP 1A-73, and WP 1A-78.

2407 PG&E-20-E, p. 1A-5, lines 16-19.

7.2.3 Voluntary Plan And Third Party Disability Management (LTD/STD Pay As You Go)

Cal Advocates' Opening Brief reiterates its position as set forth in its opening testimony, but fails to refute or even reference PG&E's rebuttal testimony.[2408]

PG&E forecast $24.069 million for these programs, which includes $22.297 million in expense for 2023 for the Voluntary Plan, including Short-Term Disability and Paid Family Leave benefits and their supplemental benefits, and $1.772 million for the Third Party Disability Program Management costs.[2409] Cal Advocates inexplicably recommends funding these programs at $2.1 million, the historic low from 2016.[2410]

When the Voluntary Plan was developed, PG&E redesigned its sick time, time off, and short term and long-term disability programs.[2411] As a result of this overhaul, employee unavailability due to health has decreased. This led to an increase in full time available workers, and reduced cost for salaries and benefits. Cal Advocates' recommendation is unreasonable and unsupported, and PG&E's forecast should be adopted.

7.2.4 Wellness Programs

Cal Advocates' Opening Brief reiterates its position as set forth in opening testimony, but fails to refute or even reference PG&E's rebuttal testimony.[2412]

PG&E forecast $6.340 million for the Wellness program.[2413] Cal Advocates recommends $3.8 million for these programs based on a three-year historical average. Cal Advocates' analysis is flawed. While Cal Advocates does not dispute that escalation, increase in employee headcount, and fluctuations over time must be taken into consideration, it fails to do

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2408 Cal Advocates Opening Brief, pp. 345.

2409 PG&E-20-E, p. 1A-4, Table 1A-1, lines 13-15.

2410 CALPA-11, p. 61, line 1 to p. 62, line 21.

2411 PG&E-20-E, p. 1A-8, lines 3-5.

2412 Cal Advocates Opening Brief, pp. 345.

2413 PG&E-20-E, p. 1A-4, Table 1A-1, line 18.

so.[2414] Cal Advocates' use of a three-year average excludes, without explanation, the years 2016 and 2017, in which the program cost $7.2 million.[2415] PG&E's forecast should be adopted.

7.2.5 Employee Assistance Program

Cal Advocates' Opening Brief reiterates its position as set forth in opening testimony, but fails to refute or even reference PG&E's rebuttal testimony.[2416] PG&E's forecast is sufficiently supported in testimony[2417] and discovery responses,[2418] and Cal Advocates offers no persuasive reason to reject it.

7.2.6 Mental Health Services

Cal Advocates' Opening Brief reiterates its position as set forth in opening testimony, but fails to refute or even reference PG&E's rebuttal testimony.[2419]

PG&E forecast $19.530 million for Mental Health Services.[2420] Cal Advocates recommends a reduction of $5.847 million based on a three-year historical average.[2421] Cal Advocates' recommendation should be rejected for two reasons: first, it fails to take into consideration that the mental health landscape has significantly changed as a result of the COVID-19 pandemic; and second, its three-year historical average is inferior to the actuarial forecast provided by Mercer. PG&E's forecast, based on Mercer's report, specifically considers

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2414 PG&E-20-E, p. 1A-9, lines 19-24.

2415 CALPA-11, p. 64, lines 2-5.

2416 Cal Advocates Opening Brief, pp. 345.

2417 PG&E-07, p. 1-14, lines 23-32.

2418 PG&E-20, PG&E's response to Data Request CalAdvocates_051-Q12, Subpart b, dated 9/15/21, pp. AppA-2 to AppA-4 and CalAdvocates_245-Q006, dated 2/10/22, pp. AppA-10 to AppA-11.

2419 Cal Advocates Opening Brief, pp. 345.

2420 PG&E-20-E, p. 1A-4, Table 1A-1, line 20.

2421 CALPA-11, p. 64-65.

PG&E's plans, PG&E employee demographics, and the Northern California environment.[2422] Mercer's report has proven to be reliable, as the 2021 actual mental health costs were 98% of the forecast provided by Mercer in support of PG&E's original funding.[2423]

7.3 Transportation And Aviation Services

7.3.1 Expense And Capital Forecasts

PG&E's TY 2023 expense forecast as reflected in rebuttal testimony is $118.082 million.[2424] PG&E's TY 2023 forecast in the JCE is $136.071 million.[2425] PG&E capital expenditures forecast as reflected in rebuttal testimony is $98.678 million in 2021, $64.677 million in 2022, and $107.569 million in 2023. PG&E's attrition year forecasts are $108,756 in 2024, $145,863 in 2025, and $246,079 in 2026.[2426] PG&E's capital expenditures forecast in the JCE is $101.689 million in 2021, $75.098 million in 2022, $130.173 million in 2023, $131.798 million in 2024, $174.485 million in 2025, and $290.612 million in 2026.[2427] Cal Advocates, AARP and TURN propose reductions to PG&E's expense and capital forecasts. These proposed reductions are unsupported and should be rejected. PG&E addresses the proposed reductions in the following sections.

7.3.1.1 Transportation Services Expense (MWC AB)

PG&E forecasts $265.767 million for miscellaneous expense in MWC AB.[2428] The fuel expense portion of MWC AB is $18.8 million (approximately 16 percent of the MWC AB

2422 PG&E-20-E, p. 1A-12, lines 4-6.

2423 PG&E-20-E, p. 1A-12, lines 17-22.

2424 PG&E Opening Brief, p. 677, and PG&E-20-E, p. 2-3, Table 2-1, line 5.

2425 PG&E Opening Brief, p. 677, and PG&E- 64, p. 3-5, Table 3A-1, lines 169-172.

2426 PG&E Opening Brief, p. 678, and PG&E-20-E, p. 2-15, Table 2-5, line 5.

2427 PG&E Opening Brief, p. 678, PG&E-67, WP-4; PG&E-07, Ch. 2, MWCs 04, 05, and Ch. 3, MWCs 21, and 2F.

2428 PG&E Opening Brief, p. 679, and PG&E-20-E, p. 2-3, Table 2-1, line 1.

forecast). Fuel expense supports day-to-day operations as well as emergency events such as wildfire.[2429]

Cal Advocates recommends a net fuel expense reduction of $3.459 million, challenging PG&E's use of a 1.55 percent consumption growth rate to develop its forecast and recommends using a historical 2-year average (2018-2019) of fuel consumption.[2430] Cal Advocates' brief adds nothing new on this subject; please see PG&E's Opening Brief at Section 7.3.2. Cal Advocates' use of a 2017-2019 historical average consumption growth rate ignores the fact that PG&E's projected headcount growth, fleet growth and miles driven are all increasing faster than 1.55%.[2431] The Commission should adopt PG&E's fuel expense forecast of $18.8 million.

7.3.1.2 Vehicle Expense (MWC AB)

PG&E's forecast for vehicle expense in MWC AB is $41.1 million. The vehicle expense is necessary to maintain and deploy safe, reliable, compliant, cost-effective vehicles and equipment to provide gas and electric services to our customers 24 hours a day, 365 days a year.[2432] Cal Advocates recommends that the labor portion of PG&E's gross vehicle expense forecast in 2023 be reduced by $3.153 million, resulting in a net reduction of $2.442 million. Cal Advocates' forecast is based on a lower forecasted labor headcount than in PG&E's forecast.[2433] Cal Advocates' brief adds nothing new on this subject; please see PG&E's Opening Brief at Section 7.3.3. PG&E amply supported its forecast, which is based on the agreed upon 35:1 optimal staffing level to meet safety and compliance requirements. Cal Advocates' reduced headcount levels ignores that staffing below the 35:1 level, while allowed,

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2429 PG&E Opening Brief, p. 679, and PG&E-20-E, p. 2-5, lines 12-17.

2430 Cal Advocates Opening Brief, p. 348.

2431 PG&E Opening Brief, p. 349, and PG&E-20-E, p. 2-7, line 20 to p. 2-8, line 2.

2432 PG&E Opening Brief, p. 680 and PG&E-20-E, p. 2-5, lines 17-21.

2433 Cal Advocates Opening Brief, p. 364 and CALPA-10, p. 11, lines 27-28.

can result in increased overtime, lower vehicle availability and delays in repair times.[2434] It also ignores that vehicle maintenance work has increase due to fire risk reduction initiatives, increased regulatory inspection requirements and vehicle safety campaign.[2435] The Commission should adopt PG&E's vehicle forecast of $41.1 million.

7.3.1.3 Overhead Credit (MWC ZC)

PG&E's forecast for Overhead Credit is $(149.762) million.[2436] Cal Advocates recommends an adjustment to Overhead Credit of $6.880 million based on its preference for using five years (2016-2020) of historical data, proposing a TY 2023 forecast of $156.642 million.[2437] Cal Advocates' brief adds nothing new on this subject; please see PG&E's Opening Brief at Section 7.3.3.1. Cal Advocates ignores recent accounting changes removing the fleet overhead credit from balancing accounts; PG&E's forecast reflects these cost model changes, is the more accurate forecast and should be adopted.[2438]

7.3.1.4 Fleet/Automotive Equipment (MWC 04)

PG&E's capital request for heavy-duty vehicles from 2023 to 2026 is $307 million; $46 million in 2023, $49 million in 2024, $87 million in 2025, $125 million in 2026. PG&E's 2023 request is a decrease from 2020 recorded capital expenditures. The primary driver of the increases, including the substantial increase in 2026, is planned vehicle replacements based on the useful lives of different asset types.

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

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2434 PG&E Opening Brief, p. 681 and PG&E-20-E, p. 2-9, line 28 to p, 2-10, line 20.

2435 PG&E Opening Brief, p. 681 and PG&E-20-E, p. 2-10, lines 5-13.

2436 PG&E Opening Brief, p. 681, and PG&E-20-E, p. 2-3, Table 2-1, line 4.

2437 PG&E Opening Brief, p. 682.

2438 PG&E Opening Brief, p. 682 and PG&E-12, p. 7-25 to p. 7-26.

its proposal to extend PG&E's planned heavy vehicle purchases by several years.[2439] AARP's brief adds nothing new on this subject; please see PG&E's Opening Brief at Section 7.3.4.

TURN proposes in its brief, for the first time, a $12.4 million reduction in electric vehicle (EV) purchases, asserting that these purchases are part of PG&E's Fleet Electrification program and that PG&E has not justified the "incremental" capital expenditures.[2440] As explained in more detail below, TURN has mischaracterized PG&E's forecast capital expenditure for EVs; the 2023-2026 forecast of EV purchases are lifecycle replacement purchases for the previously existing internal fleet electrification program, not incremental or additional purchases associated with PG&E's Fleet Electrification program.

Lifecycle replacements accounts for approximately 98 percent of the 2023 MWC 04 Gross Forecast. Transportation Services vehicle and equipment replacement plan, included in MWC 04 funding request includes capital replacement funding for the following:

- Lifecycle Replacement;
- Compliance Replacements; and
- Accident Replacements.

EV purchases will increase the Lifecycle Replacement forecast by $2.2 million in 2023, $2.5 million in 2024, $2.9 million in 2025, and $4.8 million in 2026.[2441] PG&E is committed to increasing the share of plug-in electric vehicles in the Company fleet. Electrifying vehicles at the time of lifecycle replacement allows PG&E to leverage existing planned funding for base vehicles and lower the overall costs of achieving EV goals. Starting in 2022, for the first time, there will be electric pickup trucks available from major manufacturers on the market in mass production quantities. Initial pilots will focus on sport utility vehicle and half-ton pickup truck categories with plans to start large scale purchases in 2023. To meet the 5 percent EEI

2439 AARP Opening Brief, pp. 43-44 and AARP-01, p. 62, lines 12-19.

2440 TURN Amended Opening Brief, pp. 554-555.

2441 PG&E Opening Brief, p. 683, and PG&E-07, p. 2-32, lines 28-20.

commitment for heavy-duty assets, certain aerial bucket trucks will be equipped 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.[2442]

At the time of PG&E's 2020 GRC, the Internal Fleet Electrification program was not differentiated as a distinct or named program separate from PG&E's EV Station Infrastructure program, and therefore not previously approved.[2443] The activities currently performed by the Internal Fleet Program were, at that time, conducted on a reduced scale. The Internal Fleet Program aligns with our commitment to reach net zero greenhouse gas emissions by 2040 and to electrify our vehicle fleet in alignment with the Advanced Clean Fleets Rule (currently in development at the California Air Resources Board (CARB) and expected to be voted on by CARB in early 2023).[2444]

The Commission should reject TURN's unsupported proposed disallowance and adopt PG&E's forecasts for lifecycle replacement EV purchases.

7.4 Materials

PG&E's TY 2023 expense forecast for materials in MWC AB as reflected in rebuttal testimony is $1.704 million.[2445] PG&E's TY 2023 forecast in the JCE is $1.739 million.[2446] No party disputes the MWC AB materials expense forecast.

PG&E did not include a cost variance forecast in MWC JL because "[v]ariances in the material burden overhead and material consumption rates that drive cost allocations are

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2442 PG&E-07, p. 2-32, lines 6-31.

2443 PG&E-19-E, p. 2-13, lines 4-7.ψ

2444 CA Air Resource Board's Advanced Clean Fleets Proposed Draft Regulation Language: High Priority and Federal Fleet Requirements (May 2, 2022), <https://ww2.arb.ca.gov/sites/default/files/2022-04/220502drafthpf_ADA.pdf> (as of Dec. 2, 2022).ψ

2445 PG&E Opening Brief, p. 685, and PG&E-20-E, p. 3-3, Table 3-1, line 4.

2446 PG&E Opening Brief, p. 685, and PG&E-64, p. 3-5, Table 3A-1, line 173.

unpredictable and the periodic refinement of the material burden rate attempts to get the net cost as close to the $0 as possible."[2447] Cal Advocates proposes a TY 2023 variance of $1.175 million based on a 5-year historical average. Cal Advocates' brief does not address PG&E's position and adds nothing new on this subject; please see PG&E's Opening Brief at Section 7.4.1.

PG&E's capital expenditures forecast as reflected in rebuttal testimony is $1.2 million in 2021, $1.8 million in 2022, $1.2 million in 2023, $1.2 million in 2024, $1.2 million in 2025, and $1.2 million in 2026.[2448] PG&E's capital expenditures forecast in the JCE is $1.237 million in 2021, $2.090 million in 2022, $1.452 million in 2023, $1.454 million in 2024, $1.435 million in 2025, and $1.417 million in 2026.[2449] PG&E's capital forecast is undisputed.

7.5 Sourcing

No party disputed PG&E's Sourcing forecasts. Please see PG&E's Opening Brief Section 7.5.

7.6 Real Estate

PG&E's TY 2023 expense forecast as reflected in rebuttal testimony is $60.938 million.[2450] PG&E's TY 2023 forecast in the JCE is $64.382 million.[2451] The primary drivers of increases to the 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.[2452]

2447 PG&E Opening Brief, p. 686, and CALPA-10, p. 17, lines 19-27, quoting PG&E's response to a data request from Cal Advocates.

2448 PG&E Opening Brief, p. 685, and PG&E-20-E, p. 3-8, Table 3-5, line 4.

2449 PG&E Opening Brief, p. 685, and PG&E-67, WP-4; PG&E-07, Ch. 3, MWCs 05, 21 and 2F.

2450 PG&E Opening Brief, p. 688, and PG&E-20-E, p. 5-3, Table 5-1, line 9.

2451 PG&E Opening Brief, p. 688, and PG&E-64, p. 3-5, Table 3A-1, lines 178-183.

2452 PG&E Opening Brief, p. 688, and PG&E-07, p. 5-2, lines 11-12.

PG&E's capital expenditures forecast as reflected in rebuttal testimony is $182.0 million in 2021, $176.0 million in 2022, $1,044.721 million in 2023, $183.0 million in 2024, $181.0 million in 2025, and $160.0 million in 2026.[2453] PG&E's capital expenditures forecast in the JCE is $187.544 million in 2021, $204.358 million in 2022, $1,076.813 million in 2023, $221.771 million in 2024, $216.517 million in 2025, and $188.956 million in 2026.[2454] The primary reason for the increase in capital expenditures is the purchase of and transition to the Oakland General Office at 300 Lakeside Drive and investment in service centers.[2455]

7.6.1 The Commission Should Reject Cal Advocates' Proposed Reductions To PG&E's Real Estate Expense Forecast

Cal Advocates recommends a total reduction of $21.072 million to PG&E's real estate expense forecast. Of the $21.072 million, $1.100 is forecast expense for fire risk mitigation (MWC IG) which was removed from PG&E's forecast in its November 5, 2021 Errata Testimony.[2456] An additional $1.176 million is forecast expense associated with exiting the San Ramon Bishop Ranch Building during the SFGO/Oakland Transition (MWC JH), which PG&E included in error. After reviewing Cal Advocates' testimony, PG&E agreed to correct the error and reduced its MWC JH forecast by $1.176 million.[2457] The Commission should approve a forecast of $6.611 million for MWC JH as agreed upon by PG&E and Cal Advocates.

The remaining proposed TY 2023 expense reductions are to MWC EP, Manage Properties and Buildings and MWC ZC, Overhead Credit. PG&E addresses these proposed reductions by MWC below.

2453 PG&E Opening Brief, p. 688, and PG&E-20-E, p. 5-22, Table 5-5, line 4.

2454 PG&E Opening Brief, p. 688, and PG&E-67, WP-4; PG&E-07, Ch. 5, MWCs 22, 23 and 2F.

2455 PG&E Opening Brief, p. 688, and PG&E-07, p. 5-3, lines 5-9.

2456 See generally PG&E-07, Ch. 5, which reflects PG&E's removal of the expense forecast in MWC IG for fire risk mitigation costs.

2457 PG&E Opening Brief, p. 694, and PG&E-20-E, p. 5-3, Table 5-1, line 4.

7.6.1.1 Manage Properties And Buildings (MWC EP)

PG&E forecast $109.527 million for MWC EP. Cal Advocates recommends a reduction of $14.412 million, split between two activities – Conference Centers Program and Facilities Management Program.[2458] Cal Advocates' brief adds nothing new on this subject; please see PG&E's Opening Brief at Sections 7.6.1.1 and 7.6.1.2. Cal Advocates' use of 2- and 4- year historical averages to develop forecasts for these programs completely ignores the impact of PG&E's bankruptcy and related enterprise-wide affordability efforts and the COVID-19 pandemic during those years. PG&E's TY 2023 forecasts appropriately reflect return-to-normal following several years of anomalous spending on these programs and should be adopted.

7.6.1.2 Building Services Overhead Credit (MWC ZC)

The Building Services Overhead Credit represents the offsetting credit as the Building Services overhead is applied (debited) to applicable capital and balancing account expense projects.[2459] PG&E forecast $(62.171) million for MWC ZC. Cal Advocates recommends a forecast of $(66.555) million using five years of data (2016-2020),[2460] as opposed to PG&E's use of three years of data (2017-2019).[2461]

Cal Advocates' proposal is not reasonable. Basing a forecast on five years of historical data instead of three 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. Simply put, there is not five years of data available under the 2020 GRC cost model changes and 2023 proposed cost model changes for Cal Advocates proposed methodology to work. PG&E has accounted for this cost model change in its forecast, which should be adopted.[2462]

2458 Cal Advocates Opening Brief, pp. 343-344.

2459 PG&E Opening Brief, p. 694, and PG&E-20-E, p. 5-12, lines 8-10.

2460 Cal Advocates Opening Brief, p. 353, and CALPA-10, p. 27, lines 22-23.

2461 Cal Advocates Opening Brief, p. 353, and CALPA-10, p. 28, lines 25-26.

2462 PG&E Opening Brief, p. 695, and PG&E-20-E, p. 5-13, lines 11-18.

7.6.2 Implement Real Estate Strategy (MWC 23)

Implement Real Estate Strategy provides strategic portfolio planning, real asset development, design, and project delivery services.[2463] 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. Cal Advocates recommends a reduction of $917.0 million in 2023. AARP recommends reductions of $921.0 million in 2023, $29.0 million in 2024, $47.5 million in 2025, and $37.0 million in 2026.[2464]

Cal Advocates' and AARP's proposed reductions are related to: (1) PG&E's SFGO/Lakeside Project; (2) the Aviation Center Project; and (3) security fencing at service centers.[2465] These issues are addressed below.

7.6.2.1 SFGO/Oakland Lakeside Project

In 2020, PG&E developed and obtained Commission approval of a plan to sell the SFGO complex and enter into a lease with an option to purchase 300 Lakeside in Oakland.[2466] Cal Advocates proposes to exclude all of the $892 million purchase price of the Oakland/Lakeside Property, and any related transition costs, from PG&E's 2023 capital forecast.[2467] Cal Advocates does not oppose the purchase but recommends that the purchase price be recorded in a memorandum account along with other costs associated with the transition

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2463 PG&E Opening Brief, p. 695, and PG&E-20-E, p. 5-13, lines 21-22.

2464 PG&E-20-E, p. 5-4, Table 5-2, line 2.

2465 In its Opening Brief Cal Advocates also recommends a disallowance of $41 million and $21 million for 2021 and 2022 costs for Emergency Generation Enhancement, respectively. Cal Advocates proposes that the Commission order PG&E to seek recovery of these costs through the Wildfire Mitigation Plan Memorandum Account. (pp. 355-356). PG&E removed its request for review and recovery of these costs in its February 5, 2021 Errata Testimony. See PG&E-07, Ch. 5, which reflects removal of PG&E's cost recovery request for Emergency Generation Enhancement costs.

2466 PG&E Opening Brief, p. 696 and PG&E-07, p. 5-14, lines 25-28.

2467 Cal Advocates Opening Brief, pp. 354-355.

and that these amounts be subject to prudency review.[2468] AARP opposes the purchase of the property and recommends leasing instead of purchasing.[2469]

Cal Advocates' and AARP's recommendations conflict with the Commission's decision approving the 300 Lakeside transaction, which found reasonable the following provision:

> **8.** PG&E's headquarters real estate strategy is prudent and reasonable. In particular, the SFGO sale, the SFGO interim leaseback, Lakeside building lease and option to purchase and anticipated exercise of that purchase option, and movement of PG&E's headquarters to Oakland in 2022-2023 are all reasonable.[2470]

The Commission has already determined that either lease or purchase are reasonable; AARP's argument that PG&E should lease rather than purchase 300 Lakeside is moot.[2471] Cal Advocates' argument that the capital costs of the purchase should be included in rates only after additional review and approval is similarly precluded by the Commission's approval of the settlement, which includes the following provision:

> **9.** The Settling parties agree that the terms of the Lakeside Building Lease and Purchase Option Agreement, including the Lakeside building purchase price and [various other costs] are just and reasonable, and are eligible to be placed into rates subject to true-up in the Petition for Modification process.

If the purchase price were not included in rates already, there would be nothing to true up. While certain costs associated with the SFGO sale and Lakeside transition are to be recorded in a memorandum account, these do not include the initial purchase price of $892 million, which is known and which PG&E expressly indicated would be included in its capital forecast in the

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2468 Cal Advocates Opening Brief, p. 354.

2469 AARP Opening Brief, pp. 45-48.

2470 D.21-08-027.

2471 PG&E Opening Brief, p. 697 and PG&E-20-E, p. 5-15, lines 19-23.

2023 GRC.[2472] The costs to be recorded in the memorandum account are identified as the costs associated with *moving* expenses, not the purchase price.[2473]

The Commission should approve PG&E's capital forecast, including the $892 million purchase price, as previously approved by the Commission. Cal Advocates' and AARP's belated attempts to modify the terms of the settlement and decision regarding ratemaking for the Oakland purchase should be rejected.

7.6.2.2 Aviation Operation Center

To support Aviation Services operations and to reduce operating expense from lease 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.[2474] The AOC will support PG&E fixed wing, helicopter, and drone fleets with asset storage, light maintenance and office spaces for Aviation Services personnel, including dispatch.[2475] In its brief, Cal Advocates opposes PG&E's estimate of $25 million for this project, asserting that "it is unlikely that PG&E will initiate the project with the lead time required to include such capital expenditures in 2023."[2476] Cal Advocates' brief adds nothing new on this subject; please see PG&E's Opening Brief at Sections 7.6.5.2. In summary, Cal Advocates errs in assuming that the AOC project cannot be completed in 2023, consistent with PG&E's GRC forecast.[2477] In addition, Cal Advocates' secondary claim that the project should not be funded because PG&E cannot concretely demonstrate future cost savings is a red herring; PG&E has stated that the

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2472 PG&E Opening Brief, p. 697 and PG&E-20-E, p. 5-16, lines 16-17.

2473 D.21-08-027, p. 38, FOF 12.

2474 PG&E Opening Brief, p. 698 and PG&E-20-E, p. 5-18, lines 11-13.

2475 PG&E Opening Brief, p. 698 and PG&E-07, WP 5-153.

2476 Cal Advocates Opening Brief, p. 356.

2477 PG&E Opening Brief, p. 698 and PG&E-20-E, p. 5-19, lines 7-15.

reason it is pursuing centralized aviation operation is not solely to reduce operating expense, but also to increase operational efficiencies, safety, and compliance.[2478]

The AOC will support current and future necessary aviation services. PG&E's forecast capital expenditure of $25 million should be adopted.

7.6.2.3 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.[2479]

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. AARP did not include any discussion or additional support for this disallowance in its brief, perhaps owing to the fact that it was based on nothing but inappropriate, unsupported speculation. Please see PG&E's Opening Brief at Section 7.6.5.3.

7.7 Land And Environmental Management

No party disputed PG&E's Land and Environmental Management forecasts. Please see PG&E's Opening Brief Section 7.7.

7.8 Enterprise Records And Information Management And Enterprise Data Management

PG&E, Cal Advocates, and TURN have reached an agreed-upon forecast for Enterprise Records and Information Management (ERIM) and Enterprise Data Management (EDM).[2480]

2478 PG&E Opening Brief, p. 699 and PG&E-20-E, p. 5-19, lines 16-23.

2479 PG&E-20-E, p. 5-19, line 26 to p. 5-20, line 4.

2480 *See* PG&E Opening Brief, Appendix F.

7.8.1 EDM Program (MWC AB)

PG&E, Cal Advocates, and TURN have reached an agreed-upon forecast for the EDM program.[2481]

7.9 Information Technology

PG&E, Cal Advocates, and TURN have reached an agreed-upon forecast for Information Technology (IT).[2482]

7.9.1 Baseline O&M Non-Labor (MWC JV)

PG&E, Cal Advocates, and TURN have reached an agreed-upon forecast for Baseline O&M Non-Labor.[2483]

7.9.2 Technology Investments: Solution Delivery And Operations (MWC JV)

PG&E, Cal Advocates, and TURN have reached an agreed-upon forecast for Technology Investments: Solution Delivery and Operations.[2484]

7.9.3 Technology Investments: Field Work Management, Data Enablement And Enterprise Resource Management (MWC JV)

PG&E, Cal Advocates, and TURN have reached an agreed-upon forecast for Technology Investments: Field Work Management, Data Enablement and Enterprise Resource Management.[2485]

7.9.4 Technology Investments: Core Network Infrastructure And Operations (MWC 2F)

PG&E, Cal Advocates, and TURN have reached an agreed-upon forecast for Technology Investments: Core Network Infrastructure and Operations.[2486]

2481 *See* PG&E Opening Brief, Appendix F.

2482 *See* PG&E Opening Brief, Appendix F.

2483 *See* PG&E Opening Brief, Appendix F.

2484 *See* PG&E Opening Brief, Appendix F.

2485 *See* PG&E Opening Brief, Appendix F.

2486 *See* PG&E Opening Brief, Appendix F.

7.9.5 Technology Investments Portfolio Capital (MWC 2F)

PG&E, Cal Advocates, and TURN have reached an agreed-upon forecast for Technology Investments Portfolio Capital.[2487]

7.10 Cyber and Corporate Security

No party disputed PG&E's Cyber and Corporate Security forecasts. Please see PG&E's Opening Brief Section 7.10.

7.11 Geosciences

No party disputed PG&E's Geosciences forecasts. Please see PG&E's Opening Brief Section 7.11.

7.12 Enterprise Risk Management

Cal Advocates fails to refute or even reference PG&E's rebuttal testimony in its Opening Brief.[2488] Please see PG&E's Opening Brief Section 7.12.

2487 *See* PG&E Opening Brief, Appendix F.

2488 *See generally*, Cal Advocates' Opening Brief.

8. HUMAN RESOURCES (EXHIBIT PG&E-08)

8.1 HR Solutions And Services

8.1.1 Department Costs

Cal Advocates' Opening Brief reiterates its position as set forth in its opening testimony. It does not refute or reference PG&E's rebuttal testimony. PG&E's rebuttal testimony and Opening Brief thoroughly addressed Cal Advocates' prepared testimony.[2489] PG&E will not repeat that material here.

8.1.2 Information Technology

8.2 HR Service Delivery And Inclusion

8.2.1 Department Costs

Cal Advocates' Opening Brief reiterates its position as set forth in its opening testimony. It does not refute or reference PG&E's rebuttal testimony. PG&E's rebuttal testimony and Opening Brief thoroughly addressed Cal Advocates' prepared testimony.[2490] PG&E will not repeat that material here.

8.2.2 Companywide Expenses (Workforce Transition; Tuition Refund)

Cal Advocates' Opening Brief reiterates its position as set forth in its opening testimony. It does not refute or reference PG&E's rebuttal testimony. PG&E's rebuttal testimony and Opening Brief thoroughly addressed Cal Advocates' prepared testimony.[2491] PG&E will not repeat that material here.

2489 PG&E-21, p. 2-6 to p. 2-7; PG&E Opening Brief, pp. 721-724.

2490 PG&E-21, p.3-6 line 1 to p. 3-8, line 29; PG&E Opening Brief, pp. 724-727.

2491 PG&E-21, p. 3-9 to p. 3-12; PG&E Opening Brief, pp. 727-731.

8.3 Compensation: Short Term Incentive Plan (STIP), Non-Qualified Retirement, Rewards And Recognition And Labor Escalation

8.3.1 Short Term Incentive Plan – Utility/Affiliates

8.3.1.1 Summary Of The Forecast And Parties' Recommendations

8.3.1.2 The Commission Should Reject Cal Advocates' And TURN's Recommendations To Reduce STIP Funding

The Commission should reject Cal Advocates' and TURN's respective recommendations to drastically reduce PG&E's Short Term Incentive Plan (STIP) forecast by 62.5 percent. As discussed below: (1) neither TURN nor Cal Advocates have refuted PG&E's showing that STIP is a reasonable cost of service that should be included in rates; (2) neither Cal Advocates nor TURN has demonstrated why it would be reasonable for the Commission to deviate from its most recent precedent in which it rejected cost-sharing for safety and operational metrics for San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas), and Southern California Edison Company (SCE), in favor of establishing a different, more stringent, ratemaking standard for PG&E; and (3) PG&E has demonstrated that the Company's financial health is of significant concern to customers and that the EPS financial metric provides valuable information to investors who fund PG&E's capital projects. The Commission should reject Cal Advocates' and TURN's recommendations to reduce funding for STIP.

8.3.1.2.1 STIP Is A Reasonable Cost Of Service

No party has refuted PG&E's showing that STIP is a reasonable cost of service.

TURN takes issue with one aspect of the analysis only -- whether STIP is more cost-effective to provide than a base-pay equivalent.[2492] Even assuming TURN is correct that STIP might cost the equivalent of providing that portion of compensation as base pay depending on the circumstances, that single point does not refute that the program is a reasonable cost of

[2492] TURN Amended Opening Brief, p. 559.

service. First, for clarification, no party has even asserted that STIP is more costly to provide than a base-pay alternative such that it is not reasonable to include as a component of PG&E's compensation. Further, as discussed in PG&E's rebuttal testimony and Opening Brief, STIP is a reasonable cost of service because: (1) at-risk compensation programs like STIP are an important part of PG&E's ability to attract and retain professional employees; (2) providing this compensation to employees as at risk pay rather than base pay aligns management and employee focus on important company priorities including safety and reliability; and (3) PG&E's total compensation, including its STIP forecast, is competitive with the market.[2493] The evidence with respect to the first two points above is uncontested. While Cal Advocates and TURN offer comments about the competitiveness of PG&E's total compensation in support of their STIP recommendations, those comments are directly at odds with the TCS findings that PG&E's total compensation is competitive with the market. PG&E addresses parties' comments on the TCS in Section 8.6.

8.3.1.2.2 The Commission Should Reject Cal Advocates' And TURN's Cost Sharing Recommendations For Customer Welfare Metrics

The Commission's most recent precedent for both SDG&E, SoCalGas, and SCE soundly rejects shareholder cost-sharing for STIP funding for safety and operational metrics.[2494] Neither Cal Advocates nor TURN has distinguished this recent precedent, nor have they established why it would be reasonable to apply a fundamentally different ratemaking standard in this case for PG&E. As PG&E discussed in its Opening Brief, applying the Commission's most recent precedent from the 2019 and 2021 GRCs to PG&E's current program design would result in funding of 75 to 100 percent of PG&E's STIP forecast, depending on whether PG&E

2493 PG&E Opening Brief, pp. 736-739.

2494 PG&E Opening Brief, pp. 739-740, referencing D.19-09-051, pp. 541-542 and D.21-08-036, p. 433.

has met its burden of establishing the reasonableness of the financial metric. Funding STIP at a level lower than that for PG&E would be arbitrary.

With respect to funding of Customer Welfare metrics, Cal Advocates' Opening Brief reiterates its position as set forth in its opening testimony and never addresses PG&E's evidence or even mentions PG&E's rebuttal testimony.[2495] PG&E's rebuttal testimony and Opening Brief thoroughly addressed Cal Advocates' prepared testimony.[2496] PG&E will not repeat that material here.

The only additional material Cal Advocates references in support of its general cost-sharing recommendations is a table showing the total funding authorized in rates in a number of past cases, which it claims shows a "well-settled principle of dividing the STIP funding between ratepayers and shareholders."[2497] Cal Advocates' description of Commission precedent is inaccurate when viewed in terms of the recommendations it makes in this case. First, Cal Advocates' chart shows no instance in which the Commission authorized funding as low as the 37.5 percent of the STIP forecast as Cal Advocates recommends in this case. Second, in clear conflict with CPUC Rule 12.5, the chart includes the results of non-precedential settlements, which should not be considered as support for the resolution of any policy issue in this proceeding.[2498] Third, past funding percentages of any kind were based on other STIP program designs and in some cases other utility programs. They do not address the record evidence PG&E has presented in this case about its current program design; nor do they necessarily reflect current state policies on safety and incentive compensation as set forth by the Commission in its

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2495 Cal Advocates Opening Brief, pp. 369-370.

2496 PG&E-21, p. 4-21 to p. 4-28; PG&E Opening Brief, pp. 739-743.

2497 Cal Advocates Opening Brief, p. 369.

2498 CPUC Rule of Practice and Procedure 12.5 ("Commission adoption of a settlement is binding on all parties to the proceeding in which the settlement is proposed. Unless the Commission expressly provides otherwise, such adoption does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding.")

recent incentive compensation decisions and by the legislature in AB 1054 for example. Finally, Cal Advocates does not even address the fact that this "well-settled principle" resulted in 90 percent funding for SDG&E and SoCalGas in the 2019 GRC and therefore, does not support the proposition that STIP funding should be arbitrarily divided between shareholders and customers regardless of the program design.

TURN's Opening Brief likewise reiterates its cost-sharing recommendations as set forth in its opening testimony and does not address PG&E's evidence or even mention PG&E's rebuttal testimony on the issue of cost-sharing.[2499] TURN offers the same two arguments in support of its recommendation. First, TURN argues that Customer Welfare metrics benefit both customers and shareholders and should therefore be subject to 50 percent shareholder cost-sharing.[2500] As discussed above, in its last two GRC decisions on incentive compensation, the Commission has considered and rejected this argument, each time finding that full funding of safety and operational metrics was appropriate notwithstanding the fact that they may provide benefits to both shareholders and customers.[2501] The Commission got it right in those instances. Alignment of customer and shareholder interests should be the goal in providing utility service, not a condition which requires reduction of employee compensation in rates.

Further, the authorities TURN references do not support the reasonableness of its cost-sharing recommendation. Rather than directly address the Commission's most recent precedent on this issue, TURN cites to D.00-02-046, a 22-year-old decision for the general proposition that

2499 TURN Amended Opening Brief, pp. 566-569.

2500 TURN Amended Opening Brief, pp. 565 and 566. Note that TURN's reference to a motion in PG&E's bankruptcy case is off the mark. As evidence that STIP benefits shareholders, TURN refers to a statement in the motion that the program maximizes value for the benefit of economic stakeholders. (TURN Amended Opening Brief, p. 566). The economic stakeholders TURN refers to include PG&E customers as well. (PG&E-21, p. 4-29, line 21 to p. 4-22, line 10).

2501 PG&E Opening Brief, pp. 739-740, referencing D.19-09-051, pp. 541-542 and D.21-08-036, p. 433.

STIP costs should be evenly shared between customers and shareholders.[2502] TURN makes no mention that in D.19-09-051, the Commission squarely rejected these cost staring arguments and authorized 90 percent recovery of STIP in rates. TURN also references D.21-08-036, the Commission's decision on SCE's 2021 GRC, noting that the Commission excluded funding for metrics related to financial performance and policy goals, which resulted in a total of 50 percent program funding.[2503] While that may be correct, the basis for the Commission's decision in that case was its finding that SCE had failed to establish the reasonableness of those particular metrics for funding in rates, which made up half of the program metrics.[2504] TURN fails to note that in that case, the Commission again rejected cost-sharing arguments for safety and operational metrics.[2505]

Second, TURN argues that if STIP is fully funded in rates and not paid out at target, that shareholders receive a windfall in those situations because PG&E does not return a portion of the funding to customers.[2506] The Commission should reject this argument. While TURN references instances in which STIP paid out at less than target, it also acknowledged that in other years, STIP may pay above target where performance warrants.[2507] In those years, PG&E does not recoup additional funding from customers in rates. PG&E further addressed this issue in rebuttal testimony noting that over time, forecasting at target is reasonable and below historical payout as follows:

2502 TURN Amended Opening Brief, p. 567. TURN also cites to D.14-08-032 for this proposition. However, as Cal Advocates points out, in that instance, the Commission authorized over 68 percent funding STIP in rates for a program that had a higher financial metric and a lower safety component than PG&E's current plan.

2503 TURN Amended Opening Brief, pp. 567-568, citing D.21-08-036, pp. 432-433.

2504 D.21-08-036, p. 431-433.

2505 D.21-08-036, p. 433.

2506 TURN Amended Opening Brief, p. 567.

2507 TURN-16, p. 10, lines 2-3.

> historically, forecasting at target has been an accurate method of accounting for actual STIP costs paid over time. From 2006 to 2020, PG&E's STIP Program has paid out on average 1.049 percent of target.[2508] This includes the results of years where STIP paid below target, including 2018 where the Board exercised its discretion not to pay STIP. ***Far from a windfall, if anything, the data shows that even if STIP was funded at 100 percent in rates as PG&E proposes, PG&E would still be under collecting its total program costs over time. Notwithstanding the zero payout in 2018, PG&E still spent more on this program from 2017 through 2019 than it collected in 2017 GRC rates.***[2509]

This evidence is uncontested.

As discussed at length in PG&E's Opening Brief, Cal Advocates' and TURN's cost-sharing recommendations lead to illogical and indefensible results—mainly that as PG&E has significantly increased the focus on safety and operations in the STIP and halved the weight of the financial metric compared to historical program design, the percentage of total program funding in rates would decline.[2510] Such a result would be plainly illogical based on common-sense alone. Even Cal Advocates and TURN have historically recommended to the Commission that safety and operational metrics should be fully funded in rates until their weighting in the STIP design began increasing.[2511] Further, parties' cost sharing recommendations cannot be justified in light of the Commission's and the State of California's safety policies and the statutory requirements to tie significant portions of executive compensation to safety metrics.[2512] Cal Advocates' and TURN's departure from their historic full-funding recommendations for these metrics, to the 50 percent cost-sharing recommendations presented here, should be seen for what they are—an attempt to reduce funding for salaries in rates even where PG&E has substantially modified the plan design to focus primarily on safety and

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2508 PG&E-21, Appendix A (Historical STIP Scores 2006-2020), p. 4 AtchA-1, line 17.

2509 PG&E-21, p. 4-30, line 17 to p. 4-31, line 7 (emphasis added).

2510 PG&E Opening Brief, pp. 741-743, Figures 8-2 and 8-3.

2511 PG&E Opening Brief, pp. 741-743, Figures 8-2 and 8-3.

2512 PG&E Opening Brief, p. 736 and fn. 3152.

operational goals, which the Commission has found to be of clear benefit to customers and appropriate for full funding in rates.[2513]

8.3.1.2.3 The Commission Should Reject Cal Advocates' And TURN's Proposed Reductions Related To The Earning Per Share Metric

Cal Advocates' and TURN's recommendations that PG&E's STIP forecast be reduced by 25 percent to account for the inclusion of the Earnings Per Share (EPS) financial metric should be rejected. PG&E has provided significant evidence explaining: (1) that the EPS metric measures a specific portion of the Company's financial health;[2514] (2) that the EPS information is important to investors whose investments finance PG&E's capital projects;[2515] and (3) that there is no inherent conflict of interest in including a non-GAAP financial metric in the STIP in light of the structure of the STIP as a whole, which includes a 75 percent Customer Welfare metric and other aspects of compensation such as the Long-Term Compensation Plan (LTIP) which addresses both safety and total shareholder return.[2516]

Cal Advocates states that "'Earnings from Operations' or 'Earnings Per Share' benefit shareholders rather than ratepayers and therefore, are inappropriate for ratepayer funding."[2517] First, Earnings from Operations (EFO) is not the financial metric included in PG&E's current STIP design. That was the financial metric at issue in PG&E's STIP in the 2020 GRC. Second, Cal Advocates has not addressed the evidence PG&E provided establishing the customer benefits of a financially healthy company generally and the specific insight the EPS provides to investors about the company's operations that is not apparent from a GAAP-based or share price

2513 PG&E Opening Brief, pp. 739-740, referencing D.19-09-051, pp. 541-542 and D.21-08-036, p. 433.

2514 PG&E Opening Brief, pp. 745-746.

2515 PG&E Opening Brief, p. 745.

2516 PG&E Opening Brief, p. 736, referencing Pub. Util. Code § 8389(e)(6)(A)(i)(I) and pp. 745-746, referencing AB 1054 (2019-2020 Reg. Sess.) § 2(c).

2517 Cal Advocates Opening Brief, p. 368.

view.[2518] Cal Advocates' Opening Brief reiterates its position as set forth in its opening testimony and never addresses PG&E's evidence or even mentions PG&E's rebuttal testimony. PG&E's rebuttal testimony and Opening Brief thoroughly addressed Cal Advocates' prepared testimony. PG&E will not repeat that material here.

Likewise, TURN's Opening Brief also reiterates much of its position as set forth in its opening testimony and in most instances does not address PG&E's evidence or mention PG&E's rebuttal testimony. PG&E's rebuttal testimony and Opening Brief thoroughly addressed TURN's prepared testimony.[2519] PG&E will not repeat that material here in its entirety, but summarizes the following points for clarity:

<u>First,</u> TURN continues to criticize the use of a non-GAAP measure stating that it is not a good measure of the company's financial health and does not reflect the shareholder experience.[2520] As was explained in detail in PG&E's rebuttal testimony and again in PG&E's Opening Brief, the use of non-GAAP measures is prevalent in utility incentive programs, provides insights into the company's operations that investors value; and *is not designed to provide a share price or GAAP view, which is information that is publicly available for investors*.[2521] Just because there are other financial measures that could be used, does not mean the metric PG&E has selected is unreasonable or ineffective.

<u>Second</u>, TURN continues to argue that the use of a non-GAAP financial metric, "can serve to insulate management from the financial impacts of safety missteps."[2522] PG&E has addressed this argument at length in its rebuttal testimony and in its Opening Brief.[2523] In

2518 PG&E Opening Brief, p. 745.

2519 PG&E-21, p. 4-15 to p. 4-21; PG&E Opening Brief, pp. 744-748.

2520 TURN Amended Opening Brief, pp. 560-562.

2521 PG&E Opening Brief, p. 744-748.

2522 TURN Amended Opening Brief, p. 564.

2523 PG&E Opening Brief, pp. 746-747.

summary, as AB 1054 makes clear, there is no inherent conflict of interest between financial and safety metrics.[2524] The items impacting comparability (IIC) that are adjusted from the non-GAAP financial information are done with full transparency and are in no way misleading as TURN insinuates. In fact, TURN has included a list of IIC items excluded from PG&E's 2019 financial data in its testimony.[2525] Additionally, the overall makeup of PG&E's compensation program belies TURN's argument as the EPS represents only 25 percent of the STIP compared to 75 percent for safety and operational metrics.[2526] Even beyond the STIP, many managers and directors all the way up to company executives have seen reduced compensation through the Long-Term Incentive Program (LTIP) when the company's stock price has historically dropped after significant safety events.[2527] In summary, contrary to Cal Advocates' assertion, incentive compensation for management can be significantly affected by adverse safety events both through the safety metrics included in the STIP that far outweigh the weighting of the financial component, and through other parts of PG&E's compensation program such as LTIP. It is illogical and incorrect that the inclusion of a single non-GAAP metric as one small piece of PG&E's overall compensation program somehow incents employees to act in a way that disregards safety for the purpose of trying to increase their compensation. The inference TURN attempts to draws in that respect cannot be supported by the record evidence.

PG&E has demonstrated that the Company's financial health generally is of significant interest to customers and that the EPS metric in particular provides important insights about the Company's operations to investors whose investments fund capital projects. The Commission should not reduce funding for STIP simply because one small part of the program focuses on this important objective.

2524 PG&E Opening Brief, pp. 746.

2525 TURN Amended Opening Brief, p. 564.

2526 PG&E Opening Brief, pp. 746-747.

2527 PG&E Opening Brief, pp. 746-747.

8.3.2 Non-Qualified Retirement

Cal Advocates' Opening Brief reiterates its position with respect to Supplemental Executive Retirement Plan (SERP) as set forth in its opening testimony.[2528] It does not refute or reference PG&E's rebuttal testimony.[2529] PG&E's rebuttal testimony and Opening Brief thoroughly addressed Cal Advocates' prepared testimony.[2530] PG&E will not repeat that material here.

8.3.3 Rewards And Recognition (R&R): The Commission Should Not Adopt Cal Advocates Recommendation For PG&E's R&R Program.

Cal Advocates' Opening Brief reiterates its position as set forth in its opening testimony. It does not refute or references PG&E's rebuttal testimony.[2531] PG&E's rebuttal testimony and Opening Brief thoroughly addressed Cal Advocates' prepared testimony.[2532] PG&E will not repeat that material here.

8.3.4 Labor Escalation

8.4 Employee Benefits

8.4.1 Department Costs

In PG&E's Opening Brief, PG&E inadvertently stated that no parties contested the Benefits Department cost forecast.[2533] Cal Advocates did, in fact, make recommended reductions to the this forecast in its opening testimony and in its Opening Bbrief. PG&E responds to them here.

2528 Cal Advocates Opening Brief, pp. 371-372.

2529 Cal Advocates Opening Brief, pp. 371-372.

2530 PG&E-21, p. 4-32 to p. 4-34; PG&E Opening Brief, pp. 748-750.

2531 Cal Advocates Opening Brief, pp. 372-373.

2532 PG&E-21, p. 4-34 to p. 4-35; PG&E Opening Brief, pp. 750-753.

2533 PG&E Opening Brief, p. 755.

Cal Advocates recommends a \$0.375 million reduction to the Benefits Department costs, which includes a reduction of \$0.266 million for salaries and a reduction of \$0.109 million for outside services. Cal Advocates does not oppose the departments materials forecast.[2534] It contends that PG&E has not supported or adequately justified the increase in its Test Year (TY) forecast relative to the historical data and due to the variability of the historical data,[2535] and recommends the use of a 5-year average for salaries[2536] and a 3-year average for outside services.[2537]

The increase for salaries includes labor escalation and the staffing cost increase to reflect employees hired over the course of 2020.[2538] As such, the 2023 forecast reflects the full year cost of those employees.[2539] Cal Advocates used a 5-year average of nominal dollars to calculate the 2023 forecast for salaries, which does not account for labor escalation and the staffing cost increase to reflect employees hired in 2020. Further, even if a 5-year average forecast methodology was used, which PG&E does not agree would be appropriate, the amount should be calculated using the average of base year dollars and then escalated to 2023.[2540] That would result in a salary forecast of \$2.046 million which is higher than the \$1.997 million included in PG&E's 2023 forecast.[2541]

The outside services forecasts reflects the increased cost to print and mail legal required notices to employees and retirees, updates to PG&E benefit plans to meet changing regulatory

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2534 Cal Advocates Opening Brief, p. 373-374.

2535 Cal Advocates Opening Brief, p. 3.

2536 Cal Advocates Opening Brief, p. 374.

2537 Cal Advocates Opening Brief, p. 374.

2538 PG&E-08, p. 5-35, lines 1-5 and WP 5 Vol I-4.

2539 PG&E-08, p. 5-35, lines 1-5 and WP 5 Vol I-4.

2540 The 5-year average would be calculated using PG&E-08, WP 5 Vol 1-2, average of line 1, multiplied by the 2023 escalation factor of 1.0993 found on line 14 of the same workpaper.

2541 PG&E-08, p. 5-43, Table 5-5, line 1 and WP 5 Vol I-1, line 1.

and business needs and the movement of benefits related work for HR Service Delivery & Inclusion to the Benefits team.[2542] Cal Advocates used a 3-year average (2018 to 2020) to calculate the 2023 forecast for outside services.[2543] This methodology does not account for escalation and the increase business needs described above. Further, even if a 3-year average forecast methodology was used, which PG&E does not agree would be appropriate, the amount should be calculated using the average of base year dollars and then escalated to 2023.[2544] That would result in an outside services forecast of $0.124 million which is higher than the $0.115 million recommended by Cal Advocates.[2545] Additionally, Cal Advocates' recommendation should not be adopted because using a 2018-2020 average excludes years were the outside services spend was higher, and is therefore not representative of the historical trend or PG&E's business requirements as discussed above.

Finally, Cal Advocates' comments that PG&E failed to provide 2021 recorded data in a timely manner should be given no weight. PG&E provided its 2021 recorded data to Cal Advocates on March 09, 2022 consistent with the schedule set forth in this proceeding. That was approximately 3 months before intervenor testimony was due to be served on June 13, 2022.

8.4.2 Companywide Expenses (Benefit Plans)

8.4.2.1 Summary Of PG&E's Benefit Plans

8.4.2.2 PG&E's Total Compensation Study Reflects The Value Of Employee Benefits

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2542 PG&E-08, p. 5-35, lines 6-13 and WP 5 Vol I-4.

2543 Cal Advocates Opening Brief, p. 374.

2544 The 3-year average would be calculated using PG&E-08, WP 5 Vol 1-2, average of line 3, multiplied by the 2023 escalation factor of 1.0570 found on line 16 of the same workpaper.

2545 Cal Advocates Opening Brief, p. 374.

8.4.2.3 Employee Benefits Are A Key Component Of Labor Negotiations

8.4.2.4 Benefits Forecast

8.4.2.4.1 Forecast Drivers And Methodology

8.4.2.4.2 Use Of An Actuarial Forecast Is The Appropriate Methodology

8.4.2.4.3 The Impact Of The COVID-19 Pandemic On PG&E's Medical Costs

8.4.2.4.4 Medical Programs Management And Cost Control Efforts

8.4.2.5 Cal Advocates' Significant Proposed Reductions To The Medical Plans Forecast Should Not Be Adopted

Cal Advocates has reiterated its position from opening testimony and has not refuted or even referenced PG&E's rebuttal testimony in its Opening Brief.[2546] PG&E has thoroughly addressed Cal Advocates' position in PG&E's rebuttal testimony and Opening Brief and will not repeat that information here.[2547] PG&E offers the following points for additional clarity.

<u>First,</u> Cal Advocates' recommendation to use an average of historic costs in place of an actuarial forecast is misplaced. The Commission has found that the use of an actuarial analysis to forecast medical costs is common practice and is "typical of how large employers with both insured and self-funded medical plans forecast health costs."[2548] Further, Cal Advocates has

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2546 Cal Advocates Opening Brief, pp. 375-378.

2547 PG&E-21, p. 5-10 to p. 5-13; PG&E Opening Brief, p. 755-765.

2548 PG&E Opening Brief, p. 765, citing D.14-08-032, p. 530.

offered no specific critique of the actuarial forecast other than to say that the forecast cannot be justified by a forecast headcount alone.[2549] The 2023 forecast is not justified based on increased headcount alone. The headcount increase accounts for approximately $39.8 million increase in 2023 over the base forecast provided by Mercer.[2550] As discussed in PG&E's rebuttal testimony and Opening Brief, medical cost escalation is a significant cost driver of the 2023 forecast in addition to forecast headcount increase.[2551] Cal Advocates' proposal to use a 5-year average of historic costs fails to account for both the forecast headcount increases, as well as medical cost escalation, which is the most significant driver of the forecast.

Second, Cal Advocates' disagreement with notion of pent-up demand in 2021 and 2022 from employees who postponed care in 2020[2552] does not support its recommended reductions to PG&E's forecast, as PG&E's 2023 forecast is based on a business-as-usual framework. As PG&E clearly stated in its rebuttal testimony, the 2023 actuarial forecast provided by Mercer in 2020 assumed that by 2023 there would be no lingering impacts resulting from the COVID-19 pandemic.[2553] Nevertheless, the 2021 recorded data shows health care costs beginning to rebound, although as the pandemic has continued longer than was anticipated at the time of PG&E's original testimony, the rebound has been slower than expected. PG&E's 2021 Medical

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2549 Cal Advocates Opening Brief, p. 377.

2550 PG&E-08, WP 5, Vol I-15, line 25.

2551 PG&E Opening Brief, pp. 763-764.

2552 Cal Advocates Opening Brief, p. 377.

2553 PG&E-21, p. 5-11, lines 15-22.

Program costs increased to $452.3 million based on end of year recorded costs, before adjustments.[2554]

Cal Advocates' recommendations that the Commission should deviate from its longstanding practice of adopting medical costs forecasts based on actuarial analysis in favor of a 5-year average should be rejected. Cal Advocates has not addressed the methodology or assumptions that form the basis for the actuarial analysis in any way nor has it refuted the reasonableness of its forecast. In contrast, Cal Advocates' recommendation fails to account for the most obvious and impactful drivers of the of the 2023 forecast and should not be adopted.

8.4.3 Post-Retirement Benefits

8.4.3.1 Retirement Savings Plan

PG&E forecasts $141.1 million for the employer match and administrative fees associated with PG&E's Retirement Savings Plan (401k plan).[2555] Cal Advocates disputed PG&E's forecast and proposed a $140.1 million forecast.[2556] Cal Advocates forecast is based on escalating 2020 recorded costs and does not make a specific adjustment for PG&E's forecast headcount increase.[2557] Cal Advocates notes that while PG&E forecasts 27,312 employees for 2023, its website stated at some point in time that it had 23,000 employees.[2558] As PG&E explained in its rebuttal testimony, "[t]he PG&E Corporate website is not regularly updated to reflect changing employee headcount numbers. PG&E's actual end of year 2021 employee

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2554 PG&E-21, p. 5-10, lines 22-26, referencing PG&E's Email Transmittal of the 2021 Recorded Expense and Capital Data to Service List A.21-06-021 (Mar. 9, 2022) p. 26, line 24. Cal Advocates' comments that PG&E failed to provide 2021 recorded data in a timely manner should be given no weight. PG&E provided its 2021 recorded data to Cal Advocates consistent with the schedule set forth by the ALJ in this proceeding. That was approximately 3 months before intervenor testimony was due to be served on June 13, 2022.

2555 PG&E-08, WP 5, Vol I-68.

2556 Cal Advocates Opening Brief, p. 379.

2557 Cal Advocates Opening Brief, p. 379.

2558 Cal Advocates Opening Brief, p. 379.

headcount, for employees eligible to participate in the Retirement Savings Plan was 26,400 and as of May 31, 2022 the employee headcount is 26,619, both significantly higher than the 2020 employee headcount."[2559] Cal Advocates has not addressed or refuted this evidence. Additionally, PG&E has agreed that to the extent, the Commissions' decision reduces the labor forecast, the headcount increase component of the various benefit plans should be adjusted to reflect the lower employee headcount as well.[2560] Finally, the Commission should give no weight to Cal Advocates' assertion that it had insufficient time to review PG&E's 2021 recorded data. PG&E provided its 2021 recorded data to Cal Advocates on March 09, 2022 consistent with the schedule set forth by the ALJ in this proceeding. That was approximately 3 months before intervenor testimony was due to be served.

For the foregoing reasons, PG&E's forecast is reasonable and should be adopted.

8.4.3.2 Retirement Excess Plan

PG&E forecasts $736 thousand for the Retirement Excess Plan payments and administration in 2023.[2561] Cal Advocates recommended a forecast of $359 thousand, or 50 percent of PG&E's original forecast.[2562] Cal Advocates "recommends that shareholders and ratepayers share TY 2023 companywide Employee Benefits – Retirement Excess Plan expense equally."[2563]

Cal Advocates states that "[t]his type of plan is often called 'executive retirement' because the main beneficiaries are generally company executives whose very high rates of pay

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2559 PG&E-21, p. 5-16, lines 7-11.

2560 PG&E-21, p. 5-16, lines 1-4.

2561 As PG&E noted in its rebuttal testimony, it appears that Cal Advocates testimony does not reflect PG&E's Errata submission, which included a correction to the Retirement Excess Plan forecast. (See PG&E-21, p. 5-16, fn. 33)

2562 Cal Advocates Opening Brief, p. 380.

2563 Cal Advocates Opening Brief, p. 380.

limit their participation in the tax-qualified retirement plans."[2564] This is an incorrect characterization of PG&E's program. The Retirement Excess Plan is a benefit for non-executive employees whose pension from the qualified plan is limited based on IRS rules.[2565] Executive level employees are specifically excluded from earning benefits under this plan. Rather, employees who are receiving benefits under the Retirement Excess Plan are typically 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.[2566] Currently 38 retirees—more than 50% of the retirees receiving benefits under the Retirement Excess Plan—were represented by either the Engineers and Scientists of California or the International Brotherhood of Electrical Workers during their PG&E careers.[2567]

It is appropriate and reasonable to include the Retirement Excess Plan costs in rates and the Commission should adopt PG&E's forecast without modification.

8.4.4 Other Benefits

8.4.4.1 Relocation

PG&E forecasts $7.1 million in 2023 for the Relocation program.[2568] Cal Advocates proposes a forecast of $5.3 million for PG&E's Relocation program.[2569] Cal Advocates used a four-year average that included 2017 through 2020. It did not include 2016 simply because there were more relocations than the other years and had a higher cost.[2570] PG&E excluded 2020 relocation data from the average as it was not indicative of a typical year due to COVID-

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2564 Cal Advocates Opening Brief, p. 380.

2565 PG&E-08, p. 5-19 line 28 to p. 5-20 line 5; PG&E-21, p. 5-17, lines 3-5.

2566 PG&E-21, p. 5-17, lines 5-10.

2567 PG&E-21, p. 5-17, lines 10-13.

2568 PG&E-08, p. 5-30, lines 9-10.

2569 Cal Advocates Opening Brief, p. 381.

2570 CALPA-11, p. 46, lines 3-7; Cal Advocates Opening Brief, p. 381.

19. Cal Advocates suggests this was not in fact the case, noting that PG&E had more relocations in 2020 than in any other year.[2571] As PG&E explained in rebuttal testimony, while most of those relocations were authorized in 2020, they did not take place in 2020 and were not paid for in that year; as such, the 2020 recorded data to not reflect that number of relocations:

> After a very brief pause in hiring when businesses shut-down in March 2020, as a result of the COVID-19 pandemic, PG&E resumed its recruiting efforts to fill vacancies and hire the employees required to deliver services to PG&E's customers. With the relatively quick resumption in hiring the total number of relocations offered in 2020 were approximately 11% above the 5-year average,[2572] as noted by Cal Advocates in their testimony. ***However, many of these employees as well as those offered a relocation in the latter part of 2019, were not able to complete their relocation within 12 months due to the COVID-19 pandemic closures or restrictions. Some moves have been extended over two years due to the COVID-19 pandemic.***[2573] ***Because PG&E's relocation program pays move related costs after the fact, costs that would have been recorded in 2020 have been pushed in 2021 and 2022. For this reason, PG&E believes that it is appropriate to exclude 2020 data when determining the average cost per relocation.***[2574]

Cal Advocates has not addressed or refuted this evidence. PG&E's forecast is reasonable and should be adopted without modification.

8.4.4.2 Commuter Benefits

PG&E forecasts $105 thousand for the Commuter Transit Administration.[2575] Cal Advocates proposes $0.05 million – half of PG&E's forecast.[2576] Cal Advocates offers only one sentence in support of its recommendation saying that "shareholders and ratepayers

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[2571] Cal Advocates Opening Brief, pp. 381-382.

[2572] PG&E-08, WP 5 Vol I-161, average of line 8, 2016–2020 relocations.

[2573] The average time to complete a relocation for moves initiated from 2016 – September 2019 was 298 days. For moves initiated after September of 2019, the average is just over 400 days.

[2574] PG&E-21, p. 5-21, lines 5-18 (emphasis added).

[2575] PG&E-08, p. 5-42, Table 5-3, line 7.

[2576] Cal Advocates Opening Brief, p. 382.

share the cost of administering this program."[2577] Cal Advocates does explain why it would be appropriate for shareholders to fund a regular cost of service like commuter benefits.

The Commission should not adopt Cal Advocates' recommendation. Through this program, PG&E offers a pretax commuter benefit, through which employees can have the monthly cost of their commute deducted from pay before taxes. PG&E's forecast is for the administration of the program, actual commute costs are paid by employees participating in the program.[2578] This is a standard cost of service, and common benefit offered to employees. Cal Advocates has not shown it to be in any way unreasonable to include in rates. The Commission should adopt PG&E's forecast without modification.

8.5 PG&E Academy

8.5.1 Department Costs

8.5.1.1 Cal Advocates' Recommended Reductions To The PG&E Academy Forecast Should Not Be Adopted

Cal Advocates recommends a $0.5 million reduction to the PG&E Academy department costs.[2579] The Commission should not adopt that recommendation. Cal Advocates has reiterated its position from opening testimony and has not refuted or referenced PG&E's rebuttal testimony in its Opening Brief. PG&E has thoroughly addressed Cal Advocates' position in PG&E's rebuttal testimony and Opening Brief and will not repeat that information here.

2577 Cal Advocates Opening Brief, p. 382.

2578 PG&E-08, p. 5-33, lines 8-11.

2579 Cal Advocates Opening Brief, p. 383.

8.5.1.2 The Commission Should Adopt The PG&E/ESC Memorandum Of Understanding (MOU) Resolving PG&E Academy Issues

8.5.2 PG&E Academy Training Expense

PG&E has described the nature and importance of its Gas Training activities in opening testimony.[2580] No party has taken issue with those activities. However, Cal Advocates recommends a $2.44 million reduction to the PG&E Academy Gas – Training costs for labor and non-labor.[2581] Cal Advocates states that PG&E did not provide 2021 expense data to determine if "aspirational targets" were met and therefore, recommends the use of a 5-year average of historic costs in place of PG&E's forecast.[2582]

First, Cal Advocates' arguments about the timely production of 2021 recorded data should be given no weight. PG&E provided its 2021 recorded data to Cal Advocates on March 9, 2022 consistent with the schedule set forth by the ALJ in this proceeding. That was approximately three months before intervenor testimony was due to be served.

Second, Cal Advocates states that PG&E "has included costs for certain "aspirational targets compared to 2020 recorded spend."[2583] That is incorrect. The workpapers Cal Advocates reference clearly state that PG&E reduced its forecast by $819 thousand and an additional $253 thousand in contract spend for 2021 and 2022 respectively to account for aspirational targets, notwithstanding a similar amount for those years of work compared to 2020.[2584] The only increases to PG&E's forecast are for standard labor and contract escalation.[2585]

2580 PG&E-08, p. 6-8 to p. 6-12.

2581 Cal Advocates Opening Brief, pp. 384-385.

2582 Cal Advocates Opening Brief, pp. 384-385.

2583 Cal Advocates Opening Brief, p. 384.

2584 PG&E-08, WP 6-18, lines 17-24.

2585 PG&E-08, WP 6-18, lines 17-24.

Third, Cal Advocates' proposals to use a 5-year average of nominal dollars is inappropriate as it does not account for labor escalation. Even if a 5-year average forecast methodology were to be used, which PG&E does not agree would be appropriate, the amount should be calculated using the average of base year dollars and then escalated to 2023. This would result in forecasts for labor and non-labor that are higher than what PG&E forecasts for 2023. For Gas Training Labor, the forecast would be $4.69 million, which is an increase of $0.67 million from Cal Advocates' recommendation of $4.02 million.[2586] Gas Training non-labor, the forecast would be $3.85 million, which is an increase of 0.306 million from Cal Advocates' recommendation of $3.55 million.[2587]

For the foregoing reasons, the Commission should not adopt Cal Advocates' recommendations and should adopt PG&E's forecast without modification.

8.5.3 PG&E Training Capital Expenditure

8.5.4 Occupational Health

PG&E addresses this issue in Section 7.2.1 of PG&E's Opening Brief [2588]and Section 7.2.1 of PG&E Reply Brief.

8.5.5 Workers Compensation And Onsite Clinics

Workers' compensation and Onsite Clinics are addressed in Sections 7.2.1 to 7.2.3 of PG&E's Opening Brief and in Sections 7.2.1 and 7.2.2 of PG&E's Reply Brief.

8.5.6 Disability Programs

Cal Advocates makes two recommendations: (1) for Long-Term Disability (LTD) trust contributions, Cal Advocates recommends $30.869 million as opposed to PG&E's forecast of

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2586 The 5-year average would be calculated using Exhibit PG&E-08, WP 6-2, average of line 6, multiplied by the 2023 escalation factor of 1.0993 found on line 12 of the same workpaper and Table 6-6.

2587 The 5-year average would be calculated using PG&E-08, WP 6-12, average of line 7, multiplied by the 2023 escalation factor of 1.0570 found on line 13 of the same workpaper.

2588 PG&E Opening Brief, pp. 669-670.

$45.313 million; and (2) for LTD Pay-As-You-Go (PAYG), Cal Advocates recommends $2.052 million as opposed to PG&E's forecast of $24.069 million.[2589] PG&E addresses Cal Advocates' LTD recommendation here. Cal Advocates' PAYG recommendation is addressed in Section 7.2.4 of PG&E's Opening Brief [2590] and 7.2.3 of PG&E's Reply Brief.

With respect to LTD trust contributions, Cal Advocates has reiterated its position from opening testimony and has not refuted or referenced PG&E's rebuttal testimony in its Opening Brief. Cal Advocates argues that the Commission should use a 5-year average of recorded costs in place of PG&E's forecast.[2591] The Commission should not adopt this recommendation.

PG&E's employee benefit plan trust contribution costs are reasonable, and its management of the costs is consistent with prudent employee benefit trust funding principals, sound actuarial practices, and the CPUC's past decisions regarding employee benefit trust contribution recovery. PG&E has used an actuarial forecast, provided by the plan actuaries to forecast LTD Program costs for many years.[2592] The forecast provided by PG&E's actuaries reflect plan provisions, employee census information (with an annual headcount assumption), historical health benefit claims information, and accounting discount rates and regulations in effect as of December 31, 2020.[2593] In PG&E's 2020 General Rate Case, Cal Advocates did not oppose PG&E actuarial based LTD Program forecast.[2594]

In past decisions, the Commission has allowed recovery for the cost of these benefits, provided the costs can be contributed to the trusts on a tax-deductible basis. As agreed in the 2007 GRC D.07-03-044, PG&E uses a consolidated approach for adopted contribution amounts

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2589 Cal Advocates Opening Brief, p. 386-387.

2590 PG&E Opening Brief, pp. 672-674.

2591 Cal Advocates Opening Brief, p. 388.

2592 This method was used to forecast Trust Contribution Program costs in PG&E's 2014, 2017 and 2020 General Rate Cases.

2593 PG&E-07, WP 1A-28.

2594 A.18-12-009, Hearing Exhibit (HE)-192: Cal Advocates–13, p. 6, Table 13-6.

for the Post- Retirement Benefits Other than Pension (PBOP) and Long- Term- Disability (LTD).[2595] That means that PG&E contributes the amount allowable under Internal Revenue Service (IRS) guidelines and provides a credit to customers if some portion of the CPUC approved contribution cannot be contributed on a tax- deductible basis.[2596] For that reason it is inappropriate to recommend reductions to the individual trust forecast like Cal Advocates does here.

Finally, Cal Advocates' recommendation to use a 5-year average for only one aspect of the program is unreasonable. PG&E forecasts $45.3 million for LTD,[2597] $0.002 million for PBOP-Life and zero forecast for PBOP-Med.[2598] Cal Advocates accepts the lower actuarial-based forecasts PBOP-Life and PBOP-Med[2599], but not for the LTD. If a 5-year average was to be used, which PG&E does not agree would be appropriate, that methodology should be used for all three aspects of the program. Doing so would result in a significantly higher combined forecast of $63 million as for these programs compares to the $45.032 million actuarial forecast.

Cal Advocates has not demonstrated that PG&E's forecast is in any way unreasonable, nor has it refuted or even responded to PG&E's rebuttal testimony on this issue. PG&E's use of an actuarial analysis to forecast disability program costs is consistent with commonly accepted practice and the Commission should adopt PG&E's forecast without modification.

8.5.6.1 Other Occupational Health Expenses

PG&E addresses these issues in Sections 7.2.5 to 7.2.7 of PG&E's Opening Brief[2600] and PG&E Reply Brief in Sections 7.2.4 to 7.2.6.

2595 PG&E-08, p. 5-27, lines 14-29.

2596 PG&E-08, p. 5-18, lines 15-18.

2597 PG&E-07, p. 1A-18, lines 26-27.

2598 PG&E-08, p. 5-41, Table 5-2 lines 25 and 29.

2599 CALPA-11, p. 44, lines 5-9.

2600 PG&E Opening Brief, pp. 674-677.

8.6 Total Compensation Study

The Total Compensation Study (TCS) found PG&E's 2020 target compensation was competitive at 8.9 percent of the market.[2601]

Cal Advocates does not propose any specific adjustments to PG&E's forecast based on the results of the TCS. Rather, it argues that its other proposed reductions to specific compensation and benefits plans are further justified by the TCS results.[2602] TURN also suggests that the TCS findings provide an additional justification for reducing PG&E's STIP forecast.[2603] The Commission should reject those arguments for the following reasons: (1) Parties' comments ignore the central finding of the TCS – that PG&E's total compensation is competitive with the relevant market; (2) Cal Advocates' assertions about the competitiveness of executive compensation are not supported by the TCS; (3) the independent TCS consultant has fully justified and supported the basis for the competitive range used to interpret the TCS results; no party has addressed this evidence let alone refuted it; and (4) contrary to Cal Advocates' assertion, ignoring the expert opinion of the TCS consultant about how to interpret the study results is not consistent with Commission policy.

8.6.1 Parties' Comments Ignores The TCS Finding That PG&E's Total Compensation Is Competitive

Cal Advocates makes no recommended reduction to PG&E's forecast based on the results of the TCS. However, Cal Advocates states that adjustments it has recommended "in other sections…should bring PG&E's overall total authorized compensation close to within 5% of market."[2604] TURN also suggests that the TCS findings provide an additional justification for reducing PG&E's STIP forecast.[2605]

2601 PG&E-08, p. 7-4.

2602 Cal Advocates Opening Brief, p. 391.

2603 TURN Amended Opening Brief, p. 558-559.

2604 Cal Advocates Opening Brief, p. 391.

2605 TURN Amended Opening Brief, p. 558-559.

PG&E agrees, no reduction is warranted based on the TCS. While Cal Advocates states that PG&E's target compensation was 8.9 percent above the market average the conclusion of the TCS was that PG&E's total compensation is competitive with the relevant market.[2606] Additionally, while Cal Advocates and TURN also reference that actual 2020 compensation was 10.4 percent above the market average, the target number is the relevant metric for ratemaking purposes because PG&E's cash compensation forecast is based on target cash compensation (which includes a STIP forecast at target) and not on actual cash compensation.[2607] In summary, the conclusion of the TCS was that PG&E's total compensation is competitive with the relevant market. No reductions to PG&E's forecasts are warranted based on the TCS.

8.6.2 Cal Advocates' Assertions About The Competitiveness Of Executive Compensation Are Not Supported By The TCS

With respect to executive compensation, the TCS showed actual total compensation for executives at 2.7 percent above the market mean and target compensation at 15.3 percent above the market mean.[2608] Cal Advocates states, if the "TCS consultant had used the Commission's long-standing standard of 5% as the acceptable market range variance, then PG&E's market comparison for its executive compensation would fall well above this variance."[2609]

Cal Advocates' analysis is incorrect and is not supported by the TCS.

First, the TCS is not meant to provide an opinion as to the competitiveness of any single employee cohort such as executives. The TCS specifically cautions against using the results in that way and confirms that the study is intended only to provide an estimate of the market competitiveness of total compensation at the Company level.[2610]

2606 PG&E-08, p. 7-4.

2607 PG&E-08, p. 4-6, lines 3-6.

2608 PG&E-08, p. 7-4 and p. 7-5.

2609 Cal Advocates Opening Brief, p. 391.

2610 PG&E-08, p. 7-6, ¶ 1.

Second, while Cal Advocates is correct that the range of competitiveness which applies to the TCS at the total Company level is +/- 10 percent, the TCS is very clear that a range of up to +/- 20 percent is to be expected for the executive cohort of employees.[2611]

As such, Cal Advocates' conclusion that executive compensation can be said to be above the competitive range based on the TCS or otherwise is incorrect. That argument is not supported by the record evidence and in no way "underscores that Cal Advocates' adjustments to PG&E executive compensation programs are equitable."[2612]

8.6.3 The Evidence Supporting The Competitive Range Used By The TCS Consultant Is Extensive And Undisputed

Willis Towers Watson (WTW), the independent TCS consultant, determined that a range of +/- 10 percent of the market average was appropriate to determine competitiveness for this study.[2613] That range is consistent with the industry standard[2614] and was based on 100s of senior consultants' experience conducting 1000s of benchmarking studies over the last 20 plus years.[2615] This evidence, as described in this section, is undisputed.

In the TCS, WTW explains why a +/-10 percent range of competitiveness is both consistent with industry standard and appropriate for this study, pointing primarily to: (1) natural variances between compensation levels and survey data; and (2) potential survey error.

First, with respect to variances between compensation data and survey data, WTW notes that while in some cases companies may use a range of up to a 20 percent:

2611 PG&E-08, p. 7-6, ¶ 1.

2612 Cal Advocates Opening Brief, p. 391.

2613 PG&E-08, p. 7-7.

2614 PG&E-08, p. 7-6 of this exhibit (noting that "a range of plus or minus 10 percent is generally considered by compensation professionals, including Willis Towers Watson, to account for individual employee and organizational variances that naturally occur between an organization's total compensation levels and survey data").

2615 PG&E-21, p. 7-1.

[A] range of plus or minus 10 percent is generally considered by compensation professionals, including Willis Towers Watson, to account for individual employee and organizational variances that naturally occur between an organization's total compensation levels and survey data.[2616]

WTW discusses cases where a 20 percent variance are common, noting that:

…certain PG&E employee categories, such as executives, and certain components of total compensation, such as benefits, Willis Towers Watson acknowledges that larger variances are common – in excess of plus or minus 20 percent. This variation is especially true for retirement benefits.[2617]

WTW notes that these:

…variances are typically attributed to:

- Years of experience for the employees in a role and/or tenure within the organization
- Expected and realized differences in employee performance levels impacting pay, and
- Different pay philosophies and strategies influencing a company's total pay mix (e.g. pay for performance environments can provide lower base salary, yet higher short-term incentive levels).

Second, with respect to the effect of potential survey error, WTW discusses the issue within the context of the TCS,[2618] stating:

…when job data from several organizations is analyzed by survey vendors, several variations influence the pay statistics reported for a particular job, such as:

- Matching benchmark jobs: A job is considered a good match if 80 percent of the responsibilities match, but not all organizations who submit data necessarily match the same way.
- Incumbent counts: Low incumbent counts reported by an organization providing data to a survey can influence the pay statistics reported in the survey.
- Matching career levels: Organizations have different types of structures – broadband versus traditional – therefore the number of levels and layers in the company will vary. This in turn may have an effect on the way the organization matches its jobs to survey levels, across different vendors.

2616 PG&E-08, p. 7-6.

2617 PG&E-08, p. 7-6.

2618 The Commission has also recognized "that a range of error around the survey average is to be expected even with a faultless survey methodology." (See D.00-02-046, p. 242.)

- Developing market aggregates: To derive a market value for a job, typically one or more survey sources are used. Although this approach provides a broader picture of the market, it can also lead to more variability in the data points.
- Human interpretation factors: Job matching methodology and rationale interpretation can vary between individuals.

Finally, in addition to the justification WTW provided in the TCS itself, WTW also directly opposes Cal Advocates' recommendation. WTW does not consider plus 5% to be the maximum to declare total compensation to be competitive.[2619] As referenced above, WTW described the basis for its opinion noting that it was based on 100s of senior consultants' experience conducting 1000s of benchmarking studies over the last 20 plus years.[2620] WTW also provided evidence that a +/- 10 percent competitive range and the factors influencing the range are similar to those noted by WorldatWork, which is the leading not-for-profit professional association dedicated to knowledge leadership in compensation, benefits and total rewards.[2621]

Cal Advocates has not addressed, nor refuted any of the record evidence on this point.

8.6.4 Cal Advocates' Recommendation Is Inconsistent With Commission Policy And Should Not Be Adopted

Without addressing WTW's supporting evidence for the appropriate competitive range to be used to evaluate the TCS results, Cal Advocates, asks the Commission to simply ignore it. Doing so would frustrate the very purpose of the Commission's requirement to engage an independent expert to evaluate its compensation in the GRC and would not support accurate assessment of the Utility's total compensation as demonstrated by the record evidence presented in the case.

Second, the Commission has not applied such a default measure consistently in the manner Cal Advocates suggests. Almost 30 years ago, the Commission originally noted that "[t]otal compensation that is, on average, 105 percent of market levels is likely to be <u>well within</u>

2619 PG&E-21, p. 7-1.

2620 PG&E-21, p. 7-1.

2621 PG&E-21, p. 7-1.

the range of compensation in relevant markets."[2622] The Commission did not originally say that the converse was true as a matter of Commission policy – that total compensation beyond 105 percent of market levels was by default, not competitive with the market thereby requiring adjustment.[2623] While the Commission has not always been consistent in its language around the competitive range for compensation over the years, it is important to note that the Commission has also stated the importance of examining the record evidence before it to "make an informed judgment about the maximum departure from the mean that still qualifies as the market level."[2624] Indeed it would be poor policy and make little sense to require each utility to engage an independent expert to evaluate the competitiveness of its total compensation only to ignore the study findings and the expert's opinions about how to interpret the results.

Finally, the Commission on other occasions has found total compensation in excess of +/-5 percent of the market to be reasonable based on the record evidence in those cases. For example, in PG&E's 1999 GRC, the Commission found total compensation 7.23 percent above the market average to be competitive based on the record in that case.[2625] In determining that compensation 7.23% above the survey average was reasonable in the 1999 GRC, the Commission looked to the evidence presented in that case including that there was extensive and persuasive evidence presented that a 10% range is widely accepted among experts in the compensation field.[2626] Another such example is PG&E's 2007 GRC. While PG&E's total compensation was found to be 4.71 percent above the market average in that case, the Commission's basis for finding PG&E's total compensation competitive was that it fell within the +/-10 percent range determined to be appropriate by the study consultant – not because it

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2622 D.95-12-055, p. 34, (emphasis added).

2623 D.95-12-055, p. 34, (emphasis added).

2624 D.00-02-046, p. 242.

2625 D.00-02-046, p. 505, Finding of Fact 120.

2626 D-00-02-046, p. 242.

applied a default 5 percent range. Specifically, the Commission said, “Towers Perrin considers +/- 10% of the market average to be the range of competitiveness. Since PG&E’s total compensation falls within this range, the Compensation Study indicates that PG&E’s total compensation is reasonable.”[2627]

In this case, there is extensive, undisputed, expert testimony explaining that/; (1) a +/-10 percent competitive range is consistent with industry standard; (2) that a +/- 10 percent competitive range is the appropriate range to use to interpret the TCS based on this specific study design; and (3) that a +/- 5 percent range would not be the appropriate one to measure the competitiveness of PG&E’s total compensation[2628]. This expert testimony is undisputed, and the Commission should not ignore it.

For these reasons, the TCS does not provide any independent justification for reducing PG&E’s compensation and benefits program forecasts as Cal Advocates and TURN suggest.

2627 D.07-03-044, p. 157.

2628 PG&E-08, pp. 7-6 to 7-7; PG&E-21, p. 7-1.

9. ADMINISTRATIVE AND GENERAL EXPENSES (EXHIBIT PG&E-09)

9.1 Summary Of Settlements And Stipulations

For the reasons discussed in PG&E's, Cal Advocates' and TURN's respective Opening Briefs, PG&E urges the Commission to adopt the A&G Stipulation in its entirety and without modification.[2629] If adopted, the A&G Stipulation would resolve all remaining open A&G issues with the exception of Wildfire Liability Insurance, which has been addressed through a pending settlement agreement.[2630]

PG&E wishes to offer the following corrections about the summary insurance information provided in Table 9-4 of its Opening Brief. In Table 9-4, PG&E summarized the insurance costs that would be subject to Risk Transfer Balancing Account (RTBA) treatment in light of the Wildfire Insurance Settlement reached by TURN, Cal Advocates and PG&E.[2631] Table 9-4 referenced four cost types: (1) 2023 Forecast Wildfire Liability; (2) 2023 Forecast Non-Wildfire Liability; (3) 2024-2026 Post-Yest Year Attrition Proposal; and (4) Excise Tax.[2632] PG&E offers the following corrections with respect to the summary information for the 2023 Forecast Wildfire Liability and the 2023 Forecast Non-Wildfire Liability cost items.

<u>2023 Forecast Wildfire Liability</u>

In the "Cost Recovery" column, Table 9-4 stated that costs of coverage above $1 billion would be recovered through Tier 2 Advice Letter.[2633] That is incorrect. The Wildfire Insurance

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2629 PG&E Opening Brief, p. 773, Table 9-1, and Appendix G; Cal Advocates Opening Brief, p. 392, and Attachment B; TURN Amended Opening Brief, p. 570-572, and Appendix C.

2630 PG&E Opening Brief, p. 772-773, Appendix G, p. G-1 (referencing the *Joint Motion of Pacific Gas and Electric* Company*, The Utility Reform Network and The Public Advocates Office at the California Public Utilities Commission for Expedited Approval and Adoption of the Attached Settlement Agreement on Insurance Related Issues* (October 7, 2022) *(*hereafter "Wildfire Insurance Settlement").

2631 PG&E Opening Brief, p. 795, Table, 9-4.

2632 PG&E Opening Brief, p. 795, Table, 9-4, lines 1-4.

2633 PG&E Opening Brief, p. 795, Table, 9-4, line 1.

Settlement permits PG&E to collect cost through the RTBA not to exceed a total, available self-insurance accrual amount of $1 billion for the year.[2634] In accordance with the Wildfire Insurance Settlement, PG&E has updated Table 9-4 below to remove the reference to seeking cost recovery of additional coverage through Tier 2 Advice Letter.

2023 Forecast Non-Wildfire Liability

With one exception, each of those cost types mentioned above was addressed in the Wildfire Insurance Settlement and their respective resolutions are described in the "Cost Recovery" section of Table 9-4. The exception is the 2023 Forecast Non-Wildfire Liability cost type, which was not addressed in the Wildfire Insurance Settlement. As such, the information provided in Table 9-4 for that cost item reflects PG&E's "as filed" proposal. PG&E wishes to clarify that the 2023 Forecast Non-Wildfire Liability cost type was addressed and resolved through the A&G Stipulation on remaining items.[2635] As such, PG&E should have updated the resolution for that cost item as well in Table 9-4 for clarity. In summary, the A&G Stipulation would require PG&E to seek cost recovery of costs in excess of the Non-Wildfire Liability forecast through an application, rather than through Tier 2 Advice Filing as PG&E had initially proposed. PG&E has updated Table 9-4 accordingly below in redline. The updated Table 9-4 below shows the correct application of the RTBA to all insurance cost types as agreed in the Wildfire Insurance Settlement and A&G Stipulation.

2634 Wildfire Insurance Settlement, Attachment A, Section 3.2.2.2.

2635 PG&E Opening Brief, p. 773, Table, 9-1 (referencing Opening Brief Sections 9.4.2.1; 9.4.2.2.2; and 9.4.2.6 for additional discussion).

TABLE 9-4
SUMMARY OF INSURANCE
COSTS SUBJECT TO RTBA
(MILLIONS OF NOMINAL DOLLARS)

Line No.		Amount – As Filed in A. 21-06-021	Amount – PG&E, TURN, Cal Advocates Settlement on Wildfire Insurance	Cost Recovery	Reference
1	2023 Forecast: Wildfire Liability	$707 total ($250 self-insurance; $457 other wildfire coverage if PG&E's self-insurance proposal is adopted.)	$400 million in 2023 for self-insurance only. Amount for 2024-2026 determined by adjustment mechanism and other settlement terms.	Up to $1 billion in coverage through the RTBA~~; Coverage over $1 billion through Tier 2 Advice Letter~~	Ex. 9, Ch. 3, Section C.3.b.1.b
2	2023 Forecast: Non-Wildfire Liability	$156	Not addressed in wildfire insurance settlement agreement.	Up to $700 million in coverage through the RTBA; Coverage over $700 million through ~~Tier 2 Advice Letter~~ an Application	Ex. 9, Ch. 3, Section C.3.b.1.c
3	2024-2026 PTY Attrition Proposal on Insurance	$75	$0	Through the RTBA	Ex. 11, Ch.2, Section C.3.b.1.c.i
4	Excise Tax	$33.4	2023 – At least a $14 million reduction. 2024-2026 – Reductions to the extent there are excise tax cost savings from the self-insurance only structure.	Through RTBA and Tier 2 AL as noted above for the underlying coverage type and amount	Ex. 10, Ch. 9

9.2 Forecast

9.2.1 Summary Of The Forecast

9.2.2 Updated Forecast Reflecting Settlements And Stipulations

9.3 Finance Organization Costs

9.3.1 Department Costs

9.3.2 Companywide Expenses (Bank Fees)

9.3.3 Technology Projects

9.4 Risk, Audit And Insurance

9.4.1 Department Costs

9.4.1.1 Internal Audit Staffing

9.4.1.2 Privileged Internal Audit Reports

9.4.2 Insurance

9.4.2.1 Property Insurance Forecast

9.4.2.1.1 Property Insurance (Non-Nuclear)

9.4.2.1.2 Property Insurance (Nuclear)

9.4.2.1.3 Property Insurance (Other)

9.4.2.2 General Liability Insurance

9.4.2.2.1 Wildfire Liability Insurance

9.4.2.2.2 Non-Wildfire Liability Insurance

9.4.2.3 Directors And Officers Liability Insurance

9.4.2.4 Other Liability Insurance

9.4.2.5 PG&E Corporation Allocation

9.4.2.6 Risk Transfer Balancing Account

9.4.2.6.1 Summary Of Parties' Litigation Positions

9.4.2.6.2 Summary Of Settlement And Stipulations For The RTBA

9.4.3 Information Technology

9.5 Compliance And Ethics

9.5.1 Department Costs

9.5.2 Technology Projects

9.6 Regulatory Affairs

9.6.1 Department Costs

9.6.2 Technology Projects

9.7 Law Department

9.7.1 Department Costs

9.7.2 Companywide Expense (Settlements, Judgements And Claims)

9.7.3 Technology Projects

9.8 PG&E Corporation, PG&E Executive Offices And Corporate Secretary

9.8.1 Department Costs

9.8.2 Companywide Expenses (Director Fees And Expenses)

9.9 Corporate Affairs Costs

9.10 Administrative And General Ratemaking Adjustments

10. RESULTS OF OPERATIONS (EXHIBIT PG&E-10)

10.1 Depreciation

Pursuant to ALJ DeAngelis' *E-Mail Ruling Granting Extension of Time for Depreciation Section of Briefs*, dated November 1, 2022, this section of the Reply Brief will be submitted on December 15, 2022.

10.2 Income And Property Taxes

PG&E did not submit any rebuttal testimony for income and property taxes as parties did not address PG&E's recommendations in its Opening Testimony.

On September 6, 2022, PG&E served Update Testimony in which it revised its proposed revenue requirements for the three following federal tax items: (1) Adjustments to Comply with the Internal Revenue Code (IRC) Normalization Rules; (2) Corporate Minimum Tax in the Inflation Reduction Act (IRA) of 2022; and (3) Gas Transmission (GT) Accounting Method Change pursuant to automatic change rules under Revenue Procedure 2022-14.[2636] These changes impacted proposed rates in 2023, as well as in the attrition years.

TURN is the only party to comment on the tax updates in an opening brief. TURN did not object to or address PG&E's adjustments to comply with the IRC Normalization Rules or corporate minimum tax due to the IRA. TURN objected to the GT accounting method change although it would reduce PG&E's revenue requirement request and proposed a new change to PG&E's Tax Memorandum Account (TMA). As discussed below, TURN's proposals should not be adopted.

10.2.1 Gas Transmission Accounting Method Change

As PG&E discussed in its Update Testimony, it recently filed an Application for Change in Accounting Method with its 2021 federal income tax return,[2637] pursuant to the accounting method change rules under Rev. Proc. 2022-14, related to GT costs. TURN opposes this portion

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[2636] PG&E-33, Ch. 3, Tax Updates.

[2637] PG&E submitted the method change with its 2021 federal tax return dated October 4, 2022.

of the Update Testimony on the basis that PG&E's election to update its accounting method is voluntary.[2638]

PG&E believes the 2023 GRC is the appropriate proceeding to incorporate the Gas Transmission Accounting Method change. As discussed in PG&E's response to TURN's data request,[2639] the Gas Transmission Accounting Method Change requires Internal Revenue Service approval, which PG&E believes constitutes government action. In addition, the 2023 GRC gives PG&E the first opportunity to reflect the reduction in revenue requirement due to the accounting method change. As an alternative, if the Commission declines to include the Gas Transmission method change in the 2023 GRC, PG&E will include the revenue requirement decreases in the TMA beginning in 2023 when Gas Transmission officially becomes a part of the GRC revenue requirements.

10.2.2 Tax Memorandum Account

TURN also requests the Commission to revise the TMA to confirm that it will apply to the accounting change so "the benefits from this GRC period flow to ratepayers rather than PG&E and its shareholders."[2640]

There is no need to revise the TMA, since the TMA will automatically capture Gas Transmission tax law changes (including tax accounting method changes) for the period beginning January 2023 when gas transmission officially becomes part of the GRC. The GRC TMA account was designed to "provide information to the CPUC by *tracking any differences in the authorized General Rate Case (GRC) revenue requirements* related to income tax specifically resulting from 1) net revenue changes, 2) mandatory tax law changes, tax accounting changes,

2638 TURN Amended Opening Brief, p. 619.

2639 TURN-905, PG&E's response to Data Request TURN_266-Q03, dated 9/14/22: "Applications for change in an accounting method for tax purposes require approval by the Internal Revenue Service (IRS), which constitutes governmental action." The IRS will audit the method change and could accept it, reject it, or reduce the amounts for repairs claimed.

2640 TURN Amended Opening Brief, pp. 616-617.

tax procedural changes, or tax policy changes, and 3) elective tax law changes, tax accounting changes, tax procedural changes or tax policy changes."[2641] Because gas transmission was not part of the 2020 GRC authorized revenue requirement, there is no revenue requirement difference to track, and therefore, by definition, the GRC TMA does not apply to gas transmission revenue requirements for the period before 2023.

TURN states, "[i]f the Commission Approves the Proposed Gas Transmission Accounting Method Change It Should Clarify that the Tax Memorandum Account Captures All Tax Changes."[2642] However, PG&E's 2020 GRC decision,[2643] as well SoCalGas and SDG&E's 2019 GRC decision,[2644] made clear the TMA only tracks revenue requirement related, "to mandatory tax law changes, tax accounting changes, tax procedural changes, or tax policy changes, and elective tax law changes, tax accounting changes, tax procedural changes, or tax policy changes" and not "all tax changes" as described by TURN.[2645] TURN's proposal to revise the TMA should be denied.

10.3 Working Cash

Cal Advocates and TURN address several disputed issues related to working cash and customer deposits in their Opening Briefs: (1) the projected level of customer deposits for 2023 and a potential confusion between customer deposits and refundable customer advances; (2) the revenue lag and bank lag; (3) the expense lag associated with goods and services expense; and (4) the expense lags associated with federal and state income tax expense.[2646] Cal Advocates' Opening Brief addresses the level of customer deposits for 2023, the bank lag, and the expense

2641 PG&E Gas Preliminary Statement Part DX, Tax Memorandum Account (TMA-G), par. 1 (emphasis added).

2642 TURN Amended Opening Brief, p. 620.

2643 D.20-12-005, p. 288.

2644 D.19-09-051, p. 639-640; *see also*, p. 773, Conclusion of Law (COL) 99.

2645 D.20-12-005, p. 288. *See also*, p. 406, COL 108.

2646 PG&E Opening Brief, pp. 813-814.

lag associated with federal income tax expense. Cal Advocates does not have a recommendation regarding PG&E's state income tax expense lag,[2647] nor a recommendation regarding PG&E's goods and services expense lag.[2648]

TURN's Opening Brief discusses the revenue lag, goods and services expense lag, and federal and state income tax expense lags. Except for a short section on vendor discounts in its discussion of the goods and services expense lag, TURN's Opening Brief simply summarizes and repeats portions of the prepared testimony that TURN submitted. Since PG&E's rebuttal testimony and Opening Brief fully address TURN's prepared testimony on all other issues related to working cash, including other aspects of the goods and services expense lag, PG&E will not repeat that discussion here.

10.3.1 Customer Deposits

Cal Advocates continues to propose that the Commission consider 2019 as the appropriate base year to use in place of PG&E's 2023 forecast.[2649] PG&E disagrees that 2019 is a representative year and instead proposes a forecast based on nonresidential customer deposits in 2020 and projected declines through April 2021.[2650]

Cal Advocates mistakenly claims that PG&E did not address the Commission's Covid-19 restrictions on customer deposits.[2651] This is not true, as PG&E's rebuttal testimony included several data request responses to inquiries from Cal Advocates regarding PG&E's customer deposits.[2652] The key finding in these data request responses that Cal Advocates completely

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2647 Cal Advocates Opening Brief, p. 397.

2648 Cal Advocates Opening Brief, p. 396.

2649 Cal Advocates Opening Brief, p. 394.

2650 PG&E-23-E, p. AppC-19 to p. AppC-24.

2651 Cal Advocates Opening Brief, pp. 394-395.

2652 PG&E-23-E, p. AppC-17 to p. AppC-25.

ignores is that D.20-06-003 restricts PG&E from collecting residential customer deposits.[2653] In 2019, PG&E could collect residential customer deposits, but since D.20-06-003 became effective, PG&E cannot collect residential customer deposits. For that reason, using 2019 data to project 2023 customer deposits, as Cal Advocates proposes,[2654] makes no sense. To the contrary, PG&E's projection of $81.5 million, which is based on data *after* every event cited in the section of Cal Advocates' brief on customer deposits,[2655] is more accurate and should be adopted.

Regarding section 10.3.1.2, "Ratemaking Treatment of Customer Deposits," in Cal Advocates' Opening Brief, the analysis in this section is simply wrong because customer advances and customer deposits are not the same thing, as Cal Advocates' admits.[2656]

10.3.2 Revenue Lag And Bank Lag

10.3.2.1 Bank Lag

PG&E proposes a bank lag of 0.58 days; Cal Advocates proposes 0.13 days. Cal Advocates' Opening Brief's discussion of the bank lag is notable for what it omits: (1) Cal Advocates' analysis implicitly assumes that electronic payments have a zero lag but they do not;[2657] (2) PG&E's estimated 0.58 bank lag for 2020 already reflects a high percentage of electronic payments;[2658] and (3) other factors affecting the revenue lag have changed, so PG&E's revenue lag estimate, which includes the bank lag, is reasonable.[2659] Cal Advocates

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2653 PG&E-23-E, p. AppC-21, citing D.20-06-003, pp. 37-44, and p. 147, Ordering Paragraphs (OP) 8 and 9.

2654 Cal Advocates Opening Brief, p. 395.

2655 The most recent event cited by Cal Advocates is June 30, 2021. In PG&E-23-E, p. 14-5, Figure 14-1 includes data from July 2021 through May 2022.

2656 Cal Advocates Opening Brief, p. 395.

2657 PG&E-23-E, p. 14-7, lines 5-14.

2658 PG&E-23-E, p. 14-7, lines 15-21.

2659 PG&E-23-E, p. 14-8, lines 1-5.

appears to admit that its bank lag estimate is not supported by the existing record but speculates that one day its proposal lag may become true. It states: "By TY 2023, it is highly likely that the number of customers that use electronic payments will continue to grow, reducing the bank lag to Cal Advocates' recommendation of 0.13 days."[2660] The Commission's decision must be based on the record evidence, none of which supports a bank lag as short of 0.13 days. For all of these reasons, the Commission should deny Cal Advocates' request to reduce the bank lag.

10.3.2.2 Revenue Lag

TURN's Opening Brief simply summarizes and repeats portions of its testimony regarding the revenue lag and did not address PG&E's rebuttal testimony.[2661] Since PG&E's rebuttal testimony and Opening Brief fully address TURN's prepared testimony on the revenue lag,[2662] PG&E will not repeat that discussion here. The Commission should adopt PG&E's revenue lag.

10.3.3 Goods And Services Expense Lag

Except for a short section on vendor discounts in its discussion of the goods and services expense lag, TURN's Opening Brief simply summarizes and repeats portions of its prepared testimony.[2663] PG&E will not repeat its full discussion on the goods and services expense lag here.[2664] Regarding TURN's reference to vendor discounts, its citation of D.21-08-036 to describe SCE's vendor payment practices is insufficient to conclude that PG&E's vendor

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2660 Cal Advocates Opening Brief, p. 396. Cal Advocates estimates the dollar impact of this adjustment to be a reduction in working cash of about $8.5 million. While Cal Advocates' opening brief provides a correct citation to its testimony regarding this number, the number itself appears to be considerably in error and pertain to only one line of business, Electric Generation. PG&E currently estimates the reduction to be about $22.4 million across all GRC lines of business.

2661 TURN Amended Opening Brief, pp. 576-578.

2662 PG&E-23-E, p. 14-8, line 9 to p. 14-9, line 23; PG&E Opening Brief, p. 817.

2663 TURN Amended Opening Brief, pp. 578-581.

2664 PG&E-23-E, p. 14-10, line 3, to p. 14-12, line 14; PG&E Opening Brief, pp. 817-819.

discount program and SCE's vendor discount program are "similar" as TURN claims.[2665] TURN's reliance on SCE's program to show that PG&E's goods and services expense lag is unreasonable is unsupported and should be disregarded.

10.3.4 Federal And State Income Tax Lags

TURN primarily summarizes and repeats portions of its prepared testimony without addressing PG&E's rebuttal testimony.[2666] In the opening paragraph of its discussion on this issue, TURN claims that "PG&E does not account for the various sources of revenue collected for federal and state tax payments than it paid to state and federal taxing authorities."[2667] It is not clear what TURN intends this sentence to mean. However, PG&E explained at some length in rebuttal testimony that the revenue collected for federal and state income tax expense was a prime source for funding capital expenditures for assets that serve PG&E's customers.[2668] Otherwise, PG&E's rebuttal testimony and Opening Brief fully address TURN's prepared testimony on the federal and state income tax lags,[2669] PG&E will not repeat that discussion here.

Cal Advocates does not have a recommendation for the state income tax expense lag.[2670]

For the federal income tax expense lag, Cal Advocates recommends 90 days.[2671] Cal Advocates claims that its recommendation "is an effort to replicate the tax lag that would occur if PG&E were paying taxes … ."[2672] However, Cal Advocates' "effort" falls short of its

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2665 TURN Amended Opening Brief, p. 580, including fn. 1742.

2666 TURN Amended Opening Brief, pp. 581-584.

2667 TURN Amended Opening Brief, p. 581.

2668 PG&E-23-E, pp. 14-18, lines 14-22; 14-19, lines 4-30; and 14-21, Table 14-1.

2669 PG&E-23-E, p. 14-17, line 1, to p. 14-20, line 10; PG&E Opening Brief, pp. 819-823.

2670 Cal Advocates Opening Brief, p. 397.

2671 Cal Advocates Opening Brief, p. 397.

2672 Cal Advocates Opening Brief, p. 397.

goal, because if PG&E were making quarterly federal estimated income tax payments, PG&E's federal income tax expense lag would be approximately 38 days, very close to PG&E's recommendation of 48.66 days.[2673]

Cal Advocates also claims that the 90-day lag is "consistent with Commission precedent" and "rate neutral."[2674] Cal Advocates' "Commission precedent" appears to be based on D.19-05-020. The adopted federal income tax lag in that decision was for Southern California Edison and "based primarily on estimated tax payments" over the period 2008-2015.[2675] Cal Advocates fails to explain how historical estimated tax payments for another utility as far as 15 years before the test year are relevant to determining the correct federal income tax lag for PG&E for 2023.

Cal Advocates claims that PG&E's proposed federal income tax expense lag violates the rate-neutral securitization.[2676] This is false because PG&E's proposed federal income tax expense lag is based on tax carryforwards based on previous Net Operating Losses that belong to shareholders. PG&E's income tax expense lags would be no different if the securitization had never been proposed or never happened because the securitization per se does not affect the form of the net operating losses (NOLs).[2677] Cal Advocates' entire discussion of the rate-neutral securitization fails to recognize this basic fact and the Commission should give no weight to Cal Advocates' discussion on this point.

Cal Advocates claims that "PG&E proposes to use its tax deductions as a basis to create an unreasonable and unjust burden on ratepayers"[2678] by "shorten[ing] the tax expense lag

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2673 PG&E Opening Brief, p. 822, including fn. 3540.

2674 Cal Advocates Opening Brief, p. 397.

2675 D.19-05-020, p. 307.

2676 Cal Advocates Opening Brief, pp. 397-399.

2677 PG&E-23-E, p. 14-15, lines 6-9.

2678 Cal Advocates Opening Brief, p. 398.

…"[2679] However, contrary to Cal Advocates' claim, PG&E is not shortening the expense lag because it would be approximately 38 days if PG&E were making federal estimated tax payments, as noted above. Cal Advocates states that "NOLs resulting from tax deductions 'should not affect the working cash calculation.'"[2680] What Cal Advocates fails to recognize is that by setting the income tax expense lags equal to the revenue lag, there is no working cash requirement resulting from federal and state income tax expense in this GRC.[2681] Thus, the shareholder NOLs indeed do not affect the working cash calculation, which is what Cal Advocates' brief itself states should be the case. Cal Advocates' claim that PG&E's income tax expense lags are not "neutral" is simply incorrect.

The Commission should adopt PG&E's proposed income tax expense lags.

10.4 Electric And Gas Distribution, Electric Generation, Gas Transmission And Storage Rate Base

Cal Advocates and TURN argue that PG&E should be required to file an application to allow the Commission to conduct a full reasonableness review of all amounts recorded in the Catastrophic Events Memorandum Account (CEMA) and the Wildfire Mitigation Plan Memorandum Account (WMPMA) before PG&E can seek Commission approval to include capital additions for new work in rate base in a GRC.[2682] However, as PG&E discussed in its

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2679 Cal Advocates Opening Brief, p. 398.

2680 Cal Advocates Opening Brief, p. 398.

2681 This can be seen by reference to any of the Tables 14-3 to 14-6, beginning at PG&E-10, p. 14-18. The working cash requirement in line 35 is the product of line 33 and line 34, or the difference between the revenue lag minus the expense lag multiplied by average daily expenses. What is true for the total of the 29 categories is also true for each of the 29 categories individually. For income tax expense in lines 8 and 9, the revenue lag minus the expense lag is zero, so there is no working cash impact, regardless of the level of income tax expense. Another way to see this is to change the expense amounts in line 8 or line 9; the working cash requirement will not change. Thus, there is no working cash requirement from income tax expense when the expense lag is set equal to 48.66 days.

2682 TURN Amended Opening Brief, p. 45; Cal Advocates Opening Brief, p. 301.

Opening Brief, utilities regularly update the rate base for capital additions between cases in GRCs.

The GRC is an opportunity for PG&E to "reflect its prior actual investment in plant as a part of the forecast for the next test year. Thus, when PG&E spends more money than forecast for capital projects during the prior test-period, it adjusts the next test year forecast to include the actual investment in utility plant."[2683] Here PG&E's request for authority to update its rate base for prior capital additions is an ordinary activity in a GRC. The existence of a memorandum account, by itself, does not preclude PG&E from seeking approval of such capital additions as part of its 2020 base year recorded plant and associated capital revenue requirements in this GRC.

As PG&E indicated in its Opening Brief, one purpose of a memorandum account is to allow the utility to seek cost recovery of incremental revenue requirement amounts that are not in the GRC revenue requirement for prior periods to avoid any dispute about retroactive ratemaking.[2684] When the utilities seek approval to include in rate base capital additions as of its GRC recorded base year for the purpose of forecasting its test year and post-test year capital revenue requirements, the rule against retroactive ratemaking logically is not applicable.

10.4.1.1 PG&E Has Appropriately Requested To Include Capital Expenditures Related To CEMA Events In Plant

TURN erroneously suggests that PG&E's practice of requesting an update to its rate base for capital additions related to work for which PG&E also had authority to recover amounts through memorandum accounts "first became clear recently and very pointedly in this GRC proceeding."[2685] TURN then contradicts this statement by citing a 2018 CEMA decision where

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2683 D.07-07-041, p. 3.

2684 PG&E Opening Brief, pp. 862-863; D.99-11-057, p. 7, as cited in D.03-05-076, pp. 6-7, fn. 5; D.10-04-031, p. 43 ("By tracking these costs in a memorandum account, a utility preserves the opportunity to seek recovery of these costs at a later date without raising retroactive ratemaking issues."); D.07-07-041, pp. 5-6.

2685 TURN Amended Opening Brief, p. 588.

the Commission, in approving a settlement, approved PG&E's request in its application to include in the next GRC the capital expenditures related to the same CEMA event.[2686] TURN indicates that it is an anomalous situation and this result was only obtained due to the passage of time between the filing of the CEMA application and the decision on that application.[2687] TURN's discussion is inaccurate. PG&E requested in its 2016 CEMA application to include the capital expenditures in its rate base in the following GRC pursuant to its usual practice, not because it was aware of a future delay in the proceeding.[2688] In a previous CEMA decision from 2000, the Commission similarly acknowledged that PG&E updated its rate base for capital expenditures related to a CEMA event in a GRC, even where there was no prior cost recovery decision for the same CEMA event.[2689] As these decisions show, PG&E's practice of including capital additions associated with CEMA-eligible events in GRC base year rate base amounts is not new, contrary to TURN's allegation.

TURN's intimation that PG&E's practice of updating its rate base for CEMA events was previously unknown is further contradicted by PG&E's opening testimony. PG&E clearly identified in this 2023 GRC testimony that projects associated with declared disasters in years 2016 to 2018 as provided in PG&E's 2018 CEMA Application (A.18-03-015), which at the time of filing this 2023 GRC did not have a final decision, were included in its 2020 recorded plant amounts.[2690] The 2020 recorded plant is used to calculate rate base and the 2023 GRC period capital revenue requirements.[2691] Similarly in PG&E's 2020 GRC, PG&E clearly identified in testimony that projects associated with declared disasters in years 2012 to March 2016 as

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2686 TURN Amended Opening Brief, p. 587, fn. 1757.

2687 TURN Amended Opening Brief, p. 587, fn. 1757.

2688 Application (A.) 16-10-019, PG&E's 2016 CEMA Application (Oct. 31, 2016), p. 5.

2689 See e.g., D.00-04-050, p. 10 (PG&E included capital and expense costs associated with a wildfire in the 1999 GRC request prior to the Commission's CEMA decision on the same wildfire).

2690 PG&E-10, p. 10-14, lines 11-16.

2691 PG&E-10, p. 15-3, line 17 to p. 15-9, line 6 (Sections B and C).

provided in PG&E's 2016 CEMA Application were included in its 2017 recorded plant amounts.[2692] TURN's suggestion that PG&E's practice of including amounts in rate base during a GRC related to CEMA events was newly discovered is incorrect.

Finally, TURN requests the Commission to re-open prior CEMA or other Commission decisions to determine the timing of PG&E's update for capital additions in rate base.[2693] As discussed above, TURN's allegation that somehow PG&E updates its rate base without Commission review is not accurate. There is no basis for the Commission to re-open prior decisions as TURN requests. In any event, this should not be required as cost recovery in other proceedings is not an issue within the scope of the proceeding.[2694]

10.4.1.2 PG&E Should Be Authorized To Include Amounts In Rate Base Related To The Community Rebuild Program That Are Net Of The Wildfire OII Penalty.

Cal Advocates indicates that PG&E should not be able to include in rate base 2019-2020 recorded costs related to the Community Rebuild Program. Cal Advocates requests these costs be removed from the RO model.[2695] Cal Advocates' recommendation is without merit. The Community Rebuild Program Costs for 2019 and 2020 are reasonably included in PG&E's 2020 recorded rate base as these are costs the utility reasonably incurred to restore service to the Community of Paradise in the aftermath of the 2018 Camp Fire. These costs are net of the shareholder penalty and reduced recorded plant balances for the 2017 Northern California

2692 A.18-12-009, HE-80: Exhibit (PG&E-10), p. 9-11, lines 18-20. (*See link,* http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=649511 <http://regulatorysup.utility.pge.com/Docs/GRC-2020-PhI/Hearing-Exhibits/PGE/2019/GRC-2020-PhI_Exh_PGE_20191010_Exh080_583070.pdf>, as of Dec. 2, 2022).

2693 TURN Amended Opening Brief, p. 588.

2694 *Southern California Edison* (2006) 140 Cal App. 4th 1085, 1106, par. 10.

2695 Cal Advocates Opening Brief, p. 303.

Wildfire Investigation as provided in D.20-05-019, which addressed violations and assessed penalties for the 2018 Camp Fire.[2696]

Cal Advocates also indicates that costs associated with Community Rebuild Program cannot be recovered on a forecast basis for years 2021-2022 because D.20-05-019 requires future costs associated with fire restoration to be subject to reasonableness review.[2697] Further, TURN and Cal Advocates imply unfairly that PG&E is somehow trying to ***avoid*** Commission review of the reasonableness of its capital expenditures by including capital expenditures for review in this proceeding.[2698] This is not accurate. To the contrary, the costs for the remainder of the program were known at the time of this 2023 GRC filing. As the program will occur during the 2023 GRC capital forecast period (2021-2026) and conclude in 2025, it is appropriate for PG&E to seek recovery of these known project costs on a forecast basis as with any other project forecast included in this GRC request. The reasonableness of this work and the associated forecast are addressed in detail in PG&E's Electric Distribution testimony,[2699] as discussed at length in section 10.4 of PG&E's Opening Brief.

10.5 Other Operating Revenues

10.6 Calculation Of The Revenue Requirement

Cal Advocates includes outdated tables in its Opening Brief that do not match the JCE amounts, including settlements and stipulations Cal Advocates has agreed to. These tables should not be used to calculate the final revenue requirement in this proceeding.

10.7 Payroll & Other Taxes

2696 PG&E-14, p. 3-6, line 24 to p. 3-7, line 2, and p. 3-AtchA-1.

2697 Cal Advocates' Opening Brief, p. 303.

2698 TURN Amended Opening Brief, p. 45; Cal Advocates Opening Brief, pp. 303-304.

2699 PGE-04, Ch. 23.

10.8 Administrative And General Allocation Factors And Franchise Fee Factor

11. POST TEST-YEAR RATEMAKING (PTYR) (EXHIBIT PG&E-11)

11.1 Post Test-Year Rate Mechanism

In this Section, PG&E responds to Cal Advocates' and TURN's respective recommendations with respect to: (1) PG&E's proposed attrition mechanism for 2024 through 2026; and (2) PG&E's proposed modifications to its Z-Factor tariff.

As discussed in PG&E's Opening Brief, the Commission should adopt PG&E's proposal for a traditional PTYR mechanism that models capital revenue requirement growth based on adopted TY plant additions and applies escalation rates to adopted TY expenses. There are two key components of the recommendation: (1) capital costs must be tied to test year capital additions and determined separately from expenses; and (2) expense escalation should be computed based on escalation factors that reflect cost increases in the goods and services PG&E procures.[2700] This issue is addressed further in Section 11.1 of this Reply.

PG&E has proposed modifications to its Z-Factor tariff that would allow PG&E to seek cost recovery through advice letter filing rather than an application. The Commission has approved this advice letter process for other California utilities and should approve it for PG&E as well. This issue is addressed further in Section 11.2 of this Reply.

For additional reference, Table 11-2 below further summarizes Parties' recommendations and shows where each recommendation is addressed both in PG&E's Opening and Reply Briefs.

11.1.1 PG&E's Post Test Year Proposal

PG&E requests that the Commission authorize a post test-year revenue requirement increase of $924 million in 2024 (an annual increase of 5.8 percent), $438 million in 2025 (an annual increase of 2.6 percent) and $247 million in 2026 (an annual increase of 1.4 percent). PG&E estimates the attrition adjustments will yield the revenue requirement increases set forth in Table 11-1 below.

[2700] PG&E Opening Brief, p. 835.

TABLE 11-1
POST-TEST YEAR REVENUE REQUIREMENTS
(MILLIONS OF NOMINAL DOLLARS)

Functional Area	2023 Increase Over Adopted	2024>2023	2025>2024	2026>2025
Electric Distribution	$2,878	$376	$409	$470
Gas Distribution	$513	$240	$297	$304
Electric Generation	$(51)	$8	$(418)	$(696)
Gas Transmission and Storage	$264	$299	$151	$169
Total[(a)]	$3,605	$924	$438	$247
(a) Differences due to rounding.				

The amounts in Table 11-1 reflect the reductions discussed in Section 1.2 of this Reply brief. PG&E's PTYR methodology was thoroughly discussed in its Opening Brief. Below, PG&E responds to parties' positions in their Opening Briefs.

11.1.2 PG&E's Cost-Based Proposal Is The Only Mechanism Sufficient To Cover PG&E's Costs

11.1.3 Summary Of Parties' PTYR Proposals

TURN and Cal Advocates are the only parties to dispute PG&E's PTYR proposal. In their respective Opening Briefs, TURN and Cal Advocates repeat positions from their prepared testimony. PG&E has addressed TURN's and Cal Advocates' prepared testimony in detail in its rebuttal testimony and Opening Brief and does not restate that material here. Table 11-2 shows where each of the parties' recommendations are addressed in PG&E's Opening and Reply Briefs.

TABLE 11-2
PTYR ISSUES REFERENCE LIST

Party	Issue	PG&E Opening Brief Reference	PG&E Reply Brief Section Reference
Cal Advocates	Primary Attrition Recommendation: 3% Escalation Based on CPI	pp. 839-846	11.1.4.1
	Alternative Attrition Recommendation: 2 Percent O&M Reduction	pp. 846-847	--
	PG&E's forecasted expense reductions for the Diablo Canyon Power Plant	pp. 845-846	--
	Adjustment to PG&E's Vegetation Management post-test year expenses;	pp. 845-846	--
	No adjustment to PG&E's Healthcare and Other Administrative and General (A&G) items post-test year expenses	pp. 845-846	--
	Approve parties' Settlement Agreement regarding PG&E's Wildfire Excess Liability Insurance post-test year expenses	pp. 845-846	--
	Z-factor Mechanism	p. 855	11.2.1
TURN	Primary Attrition Recommendation: Capital Additions	pp. 847-853	11.1.5
	Primary Attrition Recommendation: CPI for Expenses/Wages	pp. 853-854	--
	Alternative Attrition Recommendation: Capital Escalation Based on CPI Plus 50 Basis Points	pp. 853-854	--
	Z-factor Mechanism	p. 855	11.2.2

Additionally, the Coalition of California Utility Employees (CUE) supported the labor escalation rates included in PG&E's PTYR proposal.[2701] Specifically, CUE notes that TURN's proposal would escalate labor costs at a level below the escalation rates embedded in union contracts that PG&E cannot avoid.[2702] PG&E agrees with CUE's analysis and urges the Commission to adopt PG&E's proposed PTYR mechanism, which would escalate labor costs consistent with the terms included in PG&E's collective bargaining agreements.

2701 CUE Opening Brief, pp. 34-36.

2702 CUE Opening Brief, p. 36.

11.1.4 Cal Advocates' Proposals Should Be Rejected

Cal Advocates' primary recommendation is to set post-test year revenue increases at 3.0 percent per year based on the Consumer Price Index (CPI)[2703] —an index unrelated to utility costs and services—plus 90 basis points.[2704] Cal Advocates largely repeats arguments about why the CPI should be used that it has made in opening testimony that were already addressed in PG&E's Opening Brief. As PG&E noted in its Opening Brief, intervenor arguments that the CPI should be used to establish escalation rates and attrition year amounts have been consistently rejected by the Commission in multiple GRCs.[2705] PG&E does not repeat that material here.

PG&E's proposed two part PTYR mechanism models capital revenue requirement growth based on adopted test year (TY) plant additions, thereby allowing us to reflect in attrition year revenue requirements, the growth in rate base, depreciation expense, and taxes that will occur irrespective of expense growth. The expense component of the mechanism applies specific escalation rates to adopted test year expenses except for seven specific areas.[2706]

Cal Advocates claims that the two-part PTY mechanism in this proceeding would be unreasonable because it would not incentivize PG&E to manage and control costs.[2707] PG&E disagrees. PG&E's proposed PTYR mechanism includes such incentives. As PG&E described in rebuttal testimony:

2703 Cal Advocates Opening Brief, p. 431.

2704 Cal Advocates Opening Brief, p. 436.

2705 See PG&E's Opening Brief, pp. 74-75; see also D.04-07-022, p.278 ("Aglet has not demonstrated why it is appropriate to forecast SCE's cost changes using a measure of price changes faced by consumers instead of measures of price changes faced by utilities. SCE's escalation approach more accurately reflects utility purchases and will therefore be approved"); D.14-08-032, p. 653 ("The CPI reflects consumer retail price changes, not the escalation in wholesale purchases of utility goods and services."); D.15-11-021, pp. 390-391 (same); D.19-09-051, pp. 707-708 (same); D.21-08-036, p.547. ("As we have previously explained, the CPI reflects consumer retail price changes and does not reflect how utilities incur costs.")

2706 PG&E Opening Brief, pp. 834-835.

2707 Cal Advocates Opening Brief, p. 435.

"under California's forecast TY ratemaking approach, PG&E's shareholders bear the risks and opportunity of cost variances during the rate case cycle, giving management every incentive to manage its costs regardless of the attrition outcome;"[2708]

"PG&E's proposal already does require the utility to find efficiencies in PTY to absorb cost increases beyond escalation. Escalation factors capture the higher unit cost of resources due to inflation but do nothing to capture cost pressure driven by the need to complete additional units of work. The ongoing cost of serving new customers is not captured anywhere in PG&E's attrition proposal;"[2709]

"customer growth impacts capital costs and adjusts for changes in new customers in their proposed capital escalation rate. The same pressures exist on the expense side. Additionally, there are other cost pressures such as changes in government laws and regulations that can increase costs beyond normal escalation. These are not captured in PG&E's PTY forecasts and therefore must be offset by productivity gains in order for PG&E to earn its authorized rate of return."[2710]

Cal Advocates has not addressed nor refuted this evidence.

Additionally, Cal Advocates takes issue with PG&E's proposed PTYR methodology on the basis that parties dispute some underlying forecasts at issue in this case for programs such as vegetation management and system hardening.[2711] The Commission should not be swayed by this argument. As described in PG&E's Opening Brief, PG&E's two-part mechanism for PTYR is consistent with those that the Commission has adopted in the past including some of its most recent decisions for SCE, SDG&E and SoCalGas,[2712] and may be applied to the 2023 forecasts that the Commission ultimately deems reasonable in this proceeding.

Finally, Cal Advocates claims that in "recently litigated large energy utility GRCs, the Commission authorized attrition increases ranging from negative 9.27% to 7.5%."[2713] That is incorrect. The negative 9.27% change for 2018 in D.19-05-020 was not a change for a post-test

2708 PG&E-24-E, p. 1-17, lines 8-11.

2709 PG&E-24-E, p. 1-17, lines 11-17.

2710 PG&E-24-E, p. 1-17, lines 17-23.

2711 Cal Advocates Opening Brief, p. 435.

2712 PG&E Opening Brief, pp. 831-833.

2713 Cal Advocates Opening Brief, p. 434 at fn. 1536; and p. 436 at fn. 1548.

year but a change for a test year.[2714] Removing the incorrect 9.27% value, the correct range of results is 2.65% to 7.5%, as shown in the Table 11-3 below:[2715]

TABLE 11-3

Utility	Decision/Application (Attrition Years)	Attrition Year 1	Attrition Year 2	Attrition Year 3	Average, First Two Years
SCE	D.12-11-051, p. 3 (2013-2014)	7.17%	5.73%	NA	6.46%
SoCalGas/ SDG&E	D.13-05-010, p. 1011 (2013-2015)	2.65%	2.75%	2.75%	2.70%
PG&E	D.14-08-032, p. 2 (2015-2016)	4.57%	5.00%	NA	4.79%
SCE	D.15-11-021, p. 2 (2016-2017)	4.04%	5.04%	NA	4.54%
SCE	D.19-05-020, p. 2 (2019-2020)	6.60%	7.50%	NA	7.05%
SCE	D.21-08-036, p. 2 (2022-2023)	5.54%	6.00%	NA	5.77%
PG&E	A.21-06-021[2716]	6.50%	5.00%	3.80%	5.75%

When the error in Cal Advocates' analysis is corrected, it becomes clear that PG&E's proposed post-test year revenue requirement increases fall well within the reasonable range of those authorized in recent cases as shown in the preceding table. Of particular note are the calculated averages for the first two post-test years shown, where the 5.75% average for PG&E's current application is less than three of the values shown and also less than the two most recent values shown for SCE's two most recent GRCs.

11.1.5 TURN's Proposals Should Be Rejected

TURN repeats several positions from its opening testimony that PG&E addressed in its Opening Brief. PG&E does not respond to those again here.[2717] PG&E addressing the following issues in this Reply:

2714 D.19-05-020, Appendix C, p. C2, line 31, "Decrease Over Present Revenue Requirement in Rates." This decrease was for 2018, which was the test year in that application.

2715 It appears that Cal Advocates also incorrectly calculated the percentage change for attrition year 2013 in D.12-11-051. It is 7.17% (the percentage increase from $5.671 billion for 2012 to $6.078 billion for 2013). D.12-11-051, p. 3.

2716 Includes September 6, 2022 updates. PG&E-33, p. 4-2, Table 4-2, line 5.

2717 See Table 11-1 above for references to PG&E's Opening Brief and Reply Brief where specific issues are addressed.

1. TURN's recommendation that the Commission should not use the IHS Markit Second Quarter 2022 escalation factors included in PG&E's Update Testimony.[2718] PG&E addresses TURN's recommendation in Section 13.1.
2. TURN's proposal for a capital attrition mechanism and discussion of Commission precedent; and
3. TURN's mischaracterization of PG&E's proposed PTYR mechanism in figure 13 of its Opening Brief.

11.1.5.1 The Commission Should Not Adopt TURN's Primary Proposal To Escalate Capital Additions Based On A 7-Year Average.

With respect to capital additions, PG&E proposes a PTY mechanism that models capital revenue requirement growth by escalating a majority of the adopted test year (TY) plant additions.[2719] In contrast, TURN estimates PTY capital revenue requirement growth in two categories: (i) Category 1, which includes capital additions related to electric distribution wildfire mitigations, DCPP and gas storage based on specific capital expenditure recommendations; and (ii) Category 2, which includes capital additions for all other cost categories using a 7-year historical average (2015-2021) of capital additions escalated using the IHS Markit index.[2720] PG&E addressed this recommendation at length in its Opening Brief and the Commission should not adopt it.

PG&E disagrees with TURN's characterization of its proposed mechanism as "traditional."[2721] The traditional mechanism adopted by the Commission uses a *reasonable forecast of capital additions,* to compute capital additions in the PTY period. While before 2000, when capital additions showed no evident trend, use of a seven-year average may have been reasonable. However, PG&E's Opening Brief showed why this would not be reasonable as it would underfund the projects PG&E's plans in the attrition years for activities and investments that are necessary to provide safe and reliable service. PG&E instead proposes to escalate capital

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2718 TURN Amended Opening Brief, p. 616.

2719 PG&E Opening Brief, pp. 834-835.

2720 TURN Amended Opening Brief, pp. 598-600.

2721 TURN Amended Opening Brief, p. 592.

additions by fixed capital escalation factors. While TURN complains that PG&E's approach is "too complex," PG&E has intentionally simplified the capital cost mechanism by applying fixed escalation factors to test year additions.[2722] TURN's methodology of using a 7-year average is not a simpler PTYR approach.

11.1.5.2 Using A 7-year Average Would Significantly Underfund PG&E's Operations And Fails To Account For The Significant Capital Investment PG&E Forecasts For The 2023 GRC Period

TURN agrees to PG&E's two-part mechanism, separately computing PTY revenue requirements for capital and expense, but wants to limit capital additions in the PTY period to a 7-year average for what it describes as "Category 2" costs.[2723] The Commission should not adopt TURN's proposal. The amounts discussed in this section do not reflect changes in escalation rates that were included in PG&E's Update Testimony served on September 6, 2022.

In its Rebuttal Testimony, PG&E explained that if TURN's proposal was adopted, it would underfund PG&E's capital programs by $768 million in 2024, $916 million in 2025, and $1,226 million in 2026.[2724] This evidence is uncontested.

The Commission should not adopt a 7-year average methodology for any capital additions for the reasons described in PG&E's Opening Brief. In addition, TURN's proposal to exclude several cost categories from bottom-up forecast in its "Category 2" should be rejected for the additional reason that it fails to account for forecasts that will not follow a normal trend line and therefore, should not be adopted. TURN references Corporate Real Estate as an example, stating that PG&E's change in corporate real estate assets are more typical of ongoing operations and should be included with other assets in the seven-year historical average.[2725]

2722 PG&E Opening Brief, p. 841.

2723 TURN Amended Opening Brief, pp. 598-602.

2724 PG&E-24-E, p. 1-19, line 21 to p.1-20, line 20 and Table 1-2; see also PG&E Opening Brief, p. 850 and Table 11-4.

2725 TURN Amended Opening Brief, p. 603.

PG&E disagrees. The Commission has already approved the purchase of the Oakland headquarters in D.21-08-027.[2726] The Oakland headquarters purchase is a substantial capital and its costs addition cannot be adequately captured in any average of 2015-2021 costs. While the use of a 7-year average would underfund PG&E's operations during the attrition year, the exclusion of "Category 2" costs from bottom-up forecast as TURN proposes will also make the PTY less accurate.

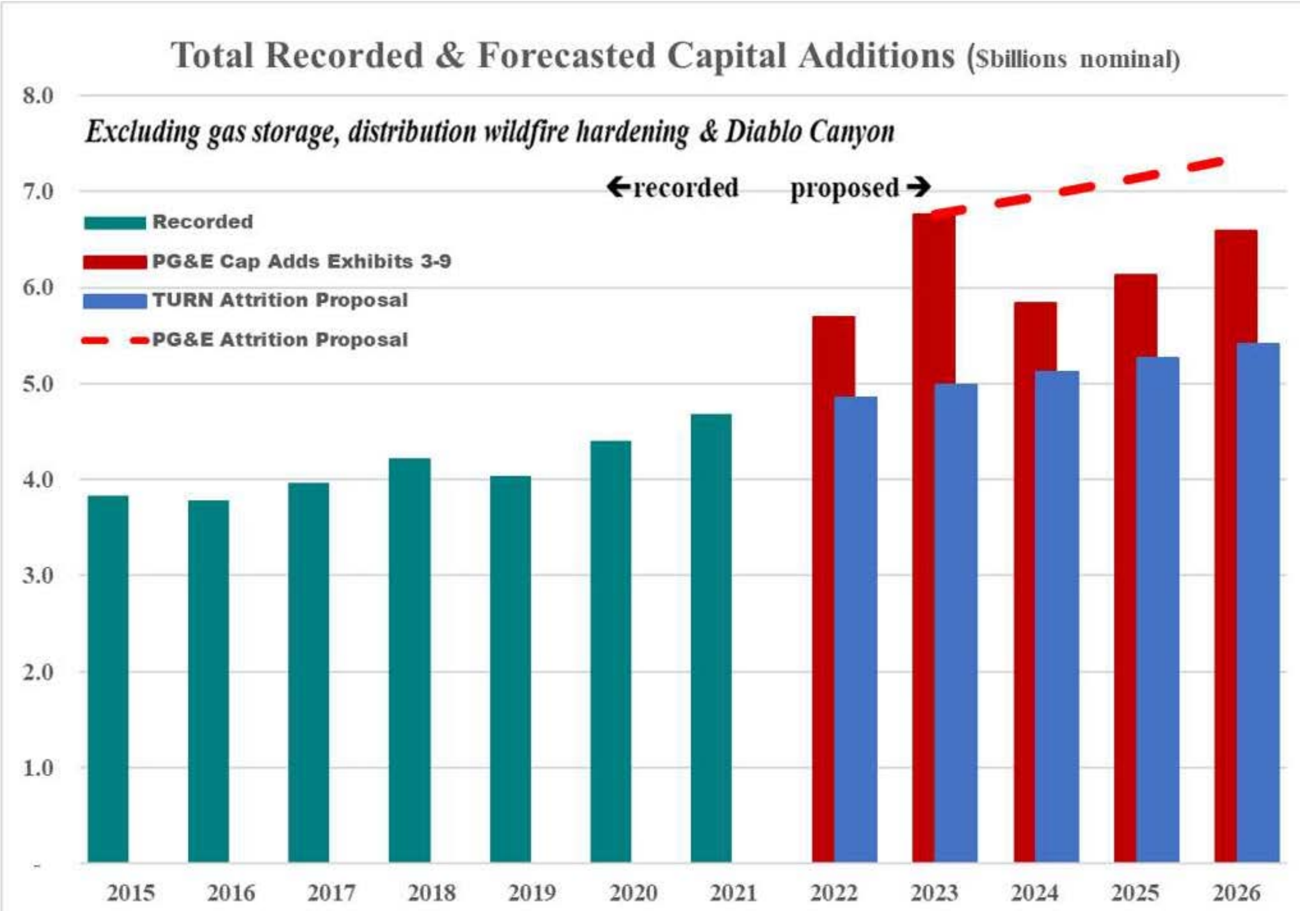
Finally, TURN continues to misunderstand a critical piece of PG&E's PTYR proposal. TURN refers to Figure 13 of its Opening Brief, which PG&E has included here as Figure 11-1 below for clarity. TURN incorrectly states that PG&E's attrition proposal for capital additions for TURN's Category 2 costs <u>is the dotted line</u> in the figure.[2727] Subject to that misunderstanding, TURN criticizes PG&E's proposal noting that if adopted by the Commission, it would result in excess revenues compared to PG&E's forecast capital addition budget during the attrition years.[2728] That is incorrect. PG&E's attrition proposal is represented by <u>the red bars</u>, which also represent PG&E's capital addition forecast for those costs for 2024-2026.

2726 D.21-08-027, p. 45, OP 10 directs PG&E to file a petition for modification within 90 days of PG&E's exercise of its option to purchase the Oakland headquarters to true up GRC revenues with the final purchase price and other costs for inclusion into rates.

2727 TURN Amended Opening Brief, pp. 601-602 and Figure 13.

2728 TURN Amended Opening Brief, pp. 602.

FIGURE 11-1
TURN OPENING BRIEF FIGURE 13



TURN incorrectly argues that if it were in fact true that the red bars represented PG&E's PTYR forecast, that PG&E's proposal would somehow reflect "a backdoor method of introducing a budget basis for capital attrition amounts."[2729] This is incorrect. As described in Exhibits (PG&E-3) to (PG&E-9) in this proceeding, PG&E has included in this application a bottom-up forecast of 2024, 2025, and 2026 capital expenditures in selected categories only. The Commission has used bottom-up capital forecasts to determine attrition revenue increases in the past.[2730] PG&E's proposal that the bottom-up forecast only be used for gas storage, nuclear generation, hydro generation, corporate real estate, and electric distribution system hardening

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2729 TURN Amended Opening Brief, p. 605.

2730 D.04-07-022.

and the community rebuild program, where there are uneven forecast capital additions in attrition years and/or the TY capital expenditures amount exceeds the PTY bottom-up forecast capital expenditures. PG&E proposed to escalate the majority of capital additions from TY to PTY except for PG&E's proposal to use bottom-up forecasts for 5 areas including: (1) Gas storage; (2) Nuclear generation; (3) Hydrogeneration; (4) Corporate real estate; and (5) Electric distribution system hardening and the community rebuild program.[2731]

With respect to CRESS, PG&E's 2023 forecast capital additions include the purchase of new Oakland headquarters building of $892 million. The dotted line represents what the PTY revenues would be if PG&E were proposing to simply escalate the adopted 2023 that include those acquisition costs. However, that is not what PG&E is proposing. Under PG&E's PTYR methodology, PG&E adjusted its 2024 forecast <u>downward</u> by almost $900 million to reflect the fact that the CRESS costs PG&E forecasts for 2023 are not forecast to recur in 2024-2026. This is one example where PG&E's use of a bottom-up forecast significantly <u>reduced</u> its PTYR forecast.[2732] PG&E's capital additions proposal for the attrition years is shown in Table 11-4 of PG&E's Opening Brief. While not exact, the red bars are more representative of PG&E's attrition proposal of Category 2 due to the exclusion of the Oakland headquarter purchase in 2023.

11.1.5.3 Using A 7-Year Average Is Not Consistent With The Majority Of Recent Precedent On The Issue

In its Opening Brief, TURN takes issues with PG&E's discussion of Commission precedent suggesting that PG&E has mischaracterized the record on this issue.[2733] PG&E disagrees.

2731 PG&E Opening Brief, pp. 834-835; PG&E-11-E, p. 1-8 lines 4-12.

2732 TURN Amended Opening Brief, p. 601, Figure 13: As shown by the red bars, PG&E's forecast capital additions for Category 2 (as defined by TURN) in 2023 is approximately $1 billion higher than forecast capital additions in year 2024 due to forecast Oakland headquarters purchase of $892 million in 2023.

2733 TURN Amended Opening Brief, pp. 602-603.

First, PG&E acknowledged that the Commission precedent on capital additions during attrition years has been mixed over the last two decades.[2734]

Second, in PG&E's description of the many Commission decisions on this issue, PG&E pointed to the Commission's decisions in PG&E's 2014 GRC and Sempra's 2019 GRC, both of which adopted 7-year average methodologies. As PG&E noted, those decisions diverge from most recent Commission precedent.[2735] TURN suggests that is not an accurate characterization.[2736] TURN's criticism is off base. In making the statement in its Opening Brief, PG&E reviewed fully litigated results on this issue in Commission decisions over the last 20 years.[2737] In contrast, TURN summarized results over the last 14 years (a different time period than PG&E evaluated), but also included results of various settlement agreements,[2738] which it knows are not precedential. The Commission has previously indicated that PTYR settlements should not be cited as precedent when evaluating the reasonableness of PTYR proposals:

> We cannot rely on the outcomes in the four prior GRC settlement agreements cited by DRA as the basis for using the CPI for attrition year escalation this proceeding. The settlements are not precedential. Similarly, five of the six cases TURN references were settlements that were non-precedential. Although prior settlements indicate that a CPI-based approach under certain circumstances may be reasonable ***as part of an overall settlement***, we cannot rely on such settlements to assess whether the CPI or another index, standing alone, is reasonable. Commission rule 12.5 states that settlements are not precedential unless the Commission expressly provides otherwise.[2739]

2734 PG&E Opening Brief, p. 851.

2735 PG&E Opening Brief, p. 851 at fn. 3654.

2736 TURN Amended Opening Brief, pp. 602-603.

2737 PG&E Opening Brief, p. 851.

2738 TURN Amended Opening Brief, p. 602, section 11.1.3.

2739 D.14-08-032, p. 660 (emphasis added). CPUC Rule of Practice and Procedure 12.5 states, "Commission adoption of a settlement is binding on all parties to the proceeding in which the settlement is proposed. Unless the Commission expressly provides otherwise, such adoption does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding."

Aside from the fact that the settled results TURN points to are not precedential, PG&E also disagrees with TURN's characterization of PG&E's 2017 and 2020 PTYR settled outcomes as one part or fixed amounts. Even though the attrition revenue increases noted in those settlements were fixed percentage increases, the computation of those revenue attrition increases were based on a two-part mechanism.

The Commission should apply a reasonable escalation approach using the test year as the best proxy for forecasting 2024 to 2026 additions, to forecast PG&E's PTYR spending. PG&E's capital investment to provide safe and reliable service are increasing at a significant pace[2740], thus programs associated with wildfire mitigation and other risk mitigation work should be escalated based on most recent estimates, rather than using a historical average that reflects spending patterns before the occurrence of these events. Reducing PG&E's 2024 to 2026 capital spending to the levels that preceded current investments in utility safety and reliability efforts would underfund those efforts going forward.

11.1.5.4 The Commission Should Not Adopt TURN's Alternative Recommendation To Escalate Capital Costs By CPI Plus 50 Basis Points

PG&E addressed this issue in its Opening Brief.[2741]

11.2 Z-Factor Memorandum Account

11.2.1 Z-Factor Adjustments Should Apply To The Test Year

Cal Advocates takes a similar position in its Opening Brief as in its prepared testimony on this issue. PG&E addressed Cal Advocates prepared testimony in its Opening Brief and will not restate that material here.

Cal Advocates states that the Commission should deny PG&E's request to apply the Z-Factor to the test year because, "a Z-factor event in PG&E's TY is unlikely."[2742] First, it is

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2740 PG&E Opening Brief, pp. 852-853.

2741 PG&E Opening Brief, pp. 853-854.

2742 Cal Advocates Opening Brief, p. 441.

important to note that PG&E is not requesting any new authority here. Tracking TY costs in the Z-factor is consistent with its current authority, which PG&E simply seeks to continue.[2743] Second, the Commission has rejected the premise of Cal Advocates' argument on multiple occasions. In authorizing the TY Z-Factor for SDG&E and SoCalGas, the Commission found, "we find that a Z-Factor event is just as likely to occur during the TY as it does during the attrition years." [2744] In adopting the 2020 GRC settlement in which Cal Advocates agreed that it was appropriate to allow tracking of TY Z-Factor costs, the Commission agreed there as well noting, "we also have no issues with tracking Z-Factor events that may occur during the TY consistent with D.19-09-051." [2745]

Cal Advocates further comments that the Z-Factor should not be applied to the test year because a one example of a potential exogenous cost related to increasing insurance premiums seems unlikely.[2746] This argument is without merit. The key word Cal Advocates seems to ignore in the Z-Factor criteria is "unforeseeable." The fact that one particular cost type has been resolved by settlement does not mean that other unforeseeable costs not included in rates may exist in the test year or the attrition years.

Finally, Cal Advocates seems to criticize PG&E's request by calling it a "me-too" request.[2747] PG&E disagrees. Again, PG&E's proposal to allow for tracking of TY costs is a continuation of its current authority under the tariff. Further, what Cal Advocates describes as "me-too" PG&E would describe as consistency in ratemaking treatment among the IOUs and the avoidance or arbitrary and capricious results. Given that the Commission has found that there is no logical basis to conclude that a Z-Factor event is more or less likely in a TY compared to a

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2743 See, D.20-12-005, pp. 333-334 and p. 409, COL 131.

2744 PG&E Opening Brief, p. 855, citing D.19-09-051, p. 712.

2745 D.20-12-005, pp. 333-334; see also p. 409, COL 131.

2746 Cal Advocates Opening Brief, p. 441.

2747 Cal Advocates opening Brief, p. 441.

PTY and has authorized the mechanism to apply to the TY for PG&E and other utilities, there is little justification for changing PG&E's Z-Factor to exclude test year events.

11.2.2 The Commission Should Permit PG&E To Seek Recovery Of Z-Factor Costs Via Advice Letter

TURN opposes PG&E's request to seek recovery of Z-Factor costs via advice letter as is authorized for SCE.[2748] TURN notes that while SCE is permitted to seek cost recovery via Advice letter, SDG&E and SoCalGas are required to file an application; therefore, it makes just as much sense to hold PG&E to the application requirement as is does to allow cost recovery request by advice letter.[2749] PG&E disagrees. Costs subject to Z-Factor treatment are necessarily unanticipated and paid upfront by the utility. Those costs are held on the utility's books while the cost recovery process is ongoing. The time period required for a utility to recoup those unanticipated costs via advice letter is considerably shorter and less resource intensive than filing an application, which can take up to 18 months to resolve. The Advice Letter process is also considerably less resource intensive for the Commission. For the same reasons of consistency in ratemaking discussed in response to Cal Advocates' recommendation above, if the Commission has found the advice letter to be an appropriate procedure to seek cost recovery of Z-Factor costs for one utility, there is little justification for reaching a different result for PG&E.

2748 TURN Amended Opening Brief, p. 610-611.

2749 TURN Amended Opening Brief, p. 610-611.

12. GENERAL REPORT (EXHIBIT PG&E-12)

12.1 Escalation Rates

Parties did not address escalation rates in Opening Briefs other than with respect to the Update Testimony discussed in Section 13 below.

12.2 Compliance With Prior Commission Decisions

Parties did not address or dispute PG&E's compliance with prior Commission decisions in Opening Briefs.

12.3 Balancing Accounts And Memorandum Accounts

Cal Advocates and TURN were the only parties to address balancing accounts and memorandum accounts in Opening Briefs. Both Cal Advocates and TURN addressed certain memorandum and balancing accounts and TURN also responded more broadly to PG&E's balancing account and memorandum account proposals.

Table 12-1 below lists the memorandum accounts and balancing accounts Cal Advocates and/or TURN addressed in their respective Opening Briefs and references where information about each balancing account and memorandum account is addressed in our Opening Brief and Reply Brief.[2750]

[2750] 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 lists all contested memorandum and balancing accounts.

TABLE 12-1
BALANCING AND MEMORANDUM ACCOUNTS ADDRESSED IN OPENING/REPLY BRIEFS

Line No.	Account	Location where Account is Discussed in PG&E's Opening Brief and Reply Brief	Location where Account is Discussed in Parties' Opening Brief(s)
Group 1: Contested Balancing and Memorandum Accounts that PG&E Proposes Continuing with No Modifications			
1	New Environmental Regulations Balancing Account (NERBA)	Opening Brief: Appendix C, Table C-1, Line 1. Opening Brief: 3.9.5; 3.14.3.3. Reply Brief: 3.14.3.4	Cal Adv.: 3.14.3.3; and 12.3.8.
Group 2: Contested Balancing and Memorandum Accounts that PG&E Proposes Continuing with Modifications			
2	Transmission Integrity Management Program Balancing Account (TIMPBA)	Opening Brief: Appendix C, Table C-2, Line 1. Opening Brief: 3.4.7; 3.4.9; 3.4.12. Reply Brief: 3.14.2	Cal Adv.: 3.1; 3.14.2; and 12.3.9. TURN: p. xix; and 3.14.2.
3	Wildfire Mitigation Balancing Accounts (WMBA)	Opening Brief: Appendix C, Table C-2, Line 2 Opening Brief: 4.3; 4.3.1.7.4; and 4.24.1. Reply Brief: 4.24.1	Cal Adv.: 4.24.1; and 12.3.3. TURN: p. xxiii; and 4.24.1.
4	Vegetation Management Balancing Account (VMBA)	Opening Brief: Appendix C, Table C-2, Line 3. Opening Brief: 4.9.1; 4.24.2; and 12.3. Reply Brief: 4.24.2	Cal Adv.: 4.9.1; and 4.24.2. TURN: p. xxiii; 4.24.1; and 4.24.2.
5	Z-Factor Memorandum Accounts (ZFMA)	Opening Brief: Appendix C, Table C-2, Line 4. Opening Brief: 11.2.2; and 12.3.2. Reply Brief: 11.2	Cal Adv: 12.3.2. TURN p. xxviii; and 12.3.2.
6	Hydro Licensing Balancing Account (HLBA)	Opening Brief: Appendix C, Table C-2, Line 5. Opening Brief: 5.4.1.2; 5.4.2; 5.8.2; and Appendix E, Reply Brief: 5.8.2	TURN 5.4; 5.4.2; 5.8.2; and Stipulation of TURN and PG&E on Energy Supply Issues.
7	Risk Transfer Balancing Accounts (RTBA)	Opening Brief: Appendix C, Table C-2, Line 6. Opening Brief: 9.1; 9.4.2; 9.4.2.6.1; 9.4.2.6.2; and Appendix G. Reply Brief: 9.1 (Settlement Agreements)	Cal Adv.: 12.3; 12.3.13; and Attachment B. TURN p. xxvii; 9.3.2; and; Stipulation of TURN, Cal Advocates and PG&E on Administrative and General Issues.
8	Gas Storage Balancing Account (GSBA)	Opening Brief: Appendix C, Table C-1, Line 7. Opening Brief: 3.6; 3.6.19; and 3.14.1.	Cal Adv: 3.14.1. TURN: p. xix; and 3.14.1.

Line No.	Account	Location where Account is Discussed in PG&E's Opening Brief and Reply Brief	Location where Account is Discussed in Parties' Opening Brief(s)
		Reply Brief: 3.14.1	
9	Diablo Canyon Retirement Balancing Account (DCRBA)	Opening Brief: Appendix B, Table B-3, Line 19. Opening Brief: 5.3.2; 5.3.3; and 5.8.5. Reply Brief: 5.8.5	TURN: 5.3.2; and 5.8.5.
Group 3: PG&E's Proposed New Balancing and Memorandum Accounts – Contested			
10	Catastrophic Event Straight-Time Labor Balancing Account (CESTLBA)	Opening Brief: Appendix C, Table C-3, Line 1. Opening Brief: 4.6; 4.6.3; 12.3.1; and 12.3.3.2. Reply Brief: 4.6.4	Cal Adv: 4.6.1; and 12.3.1. TURN 3.12.1; and 4.6.1.
11	Helms Capacity Memo Account (HCMA):	Opening Brief: Appendix C, Table C-2, Line 2. Opening Brief: 5.8.3; and Appendix E. Reply Brief: 5.8.3	TURN: p. xxv; 5.4; 5.8.3; and Stipulation of TURN and PG&E on Energy Supply Issues.
Group 4: Balancing Accounts and Memorandum Accounts PG&E Proposes Closing – Contested			
12	Transmission Integrity Management Program Memorandum Account (TIMPMA)	Opening Brief: Appendix C, Table C-4, Line 1. Opening Brief: 3.4.7; and 3.14.2. Reply Brief: 3.14.2	Cal Adv: 3.1; 3.14.2; and 12.3.9. TURN: p. xix; and 3.14.2
13	Internal Corrosion Balancing Account (ICBA)	Opening Brief: Appendix C, Table C-4, Line 2. Opening Brief: 3.8; 3.8.5; and 3.14.3.2 Reply Brief: 3.14.3.3	Cal Adv.: 3.14.3.4; and 12.3.7.
14	In-Line Inspection Memorandum Account (ILIMA)	Opening Brief: Appendix C, Table C-4, Line 3. Opening Brief: 3.4.8; and 3.14.3.1. Reply Brief: 3.14.3.1	Cal Adv.: 1.2.1; and 12.3.11. TURN: p. xix; and 3.14.3.
15	Internal Corrosion Direct Assessment Memorandum Account (ICDAMA)	Opening Brief: Appendix C, Table C-4, Line 4. Opening Brief: 3.4.2; 3.4.2.4; 3.4.9; and 3.14.3.1. Reply Brief: 3.14.3.2	Cal Adv.: 1.2.1; 3.1; and 12.3.10.
16	In-Line Inspection Balancing Account (ILIBA)	Opening Brief: Appendix C, Table C-4, Line 5. Opening Brief: 3.4.8 Reply Brief: 3.14.3.1	Cal Adv.: 1.2.1; and 12.3.11. TURN: p. xix; and 3.14.3.
Group 5: New Accounts Proposed by Parties in Opening Briefs			
17	Memorandum Account for PG&E's Lakeside Office	Opening Brief: N/A Reply Brief: 7.6.2.1	Cal Adv.: 1.2.8; 7.6.2.1; and 12.3.12

Line No.	Account	Location where Account is Discussed in PG&E's Opening Brief and Reply Brief	Location where Account is Discussed in Parties' Opening Brief(s)
Group 6: Other Memorandum and Balancing Accounts			
18	Wildfire Mitigation Plan Memorandum Account (WMPMA)	Opening Brief: 4.12.3, 10.4, 10.4.2	Cal Adv. 12.3.4.
Group 7: New Accounts Proposed by Parties in Reply Briefs			
19	Gas Distribution New Business Balancing Account (GDNBBA)	Opening Brief: N/A Reply Brief: 3.13.2 and 3.14.3.5	

In addition to parties' discussions regarding specific balancing and memorandum accounts, TURN also recommends that the Commission "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."[2751] PG&E submits that numerous memorandum and balancing accounts proposed in this case already address those topics.

For example, in traditional utility ratemaking a two-way balancing account compares revenue and expenses to authorized revenue and allows over-collections to be refunded to customers and under-collections to be recovered through rates.[2752] The Commission typically adopts a two-way balancing account when costs are not readily predictable or are subject to change. In a recent decision approving a settlement agreement for Southwest Gas, the Commission explained that "[c]onsidering that this is a large project with many variables, a two-way balancing account ensures that ratepayers only pay for actual costs and ensures that Southwest Gas will have sufficient funds to establish the project."[2753] In that case, the Commission approved a mechanism under which Southwestern Gas filed a Tier 3 advice letter

2751 TURN Amended Opening Brief, p. 606.

2752 California Public Utilities Commission, Standard Practice Audit Manual, Utility Audits Branch, January 2021, p. 6.

2753 D.20-07-016, p. 9.

for amounts between 100% and 110% of the forecast and an application for reasonableness review of amounts over 110%. The Commission explained "[w]e also find that a reasonableness review of projected costs that were already reviewed in this application is not necessary, except that costs in excess of 110 percent of what was forecast and reviewed in this application should be subject to a reasonableness review by the Commission."[2754]

PG&E is proposing a similar approach for a number of the balancing accounts at issue in this proceeding. For example, under our WMBA, VMBA and TIMPBA proposals, PG&E would be required to file a Tier 2 advice letter for costs exceeding 100 percent of the adopted amount up to a threshold amount. Costs in excess of the threshold amount are subject scrutiny by the Commission and intervenors, through a reasonableness review application process. This is the same structure as was approved for Southwest Gas, although the percentages vary and PG&E is proposing a Tier 2 advice letter process rather than Tier 3.

The Tier 2 advice letter process allows for full transparency of recorded costs that parties can review and protest, if appropriate, but provides for more expeditious review and approval of these costs. If no party protests the advice letter, Commission staff review and approve the costs. If parties protest the advice letter, parties can request a change to a Tier 3 advice letter, which requires the Commission to issue a decision approving the costs presented in the advice letter. This ratemaking mechanism allows for regular Commission oversight of PG&E's spending and full transparency of costs. In addition, because there is a reasonableness review above a certain percentage, it promotes cost control. TURN's recommendation is unnecessary and should be disregarded by the Commission.

12.3.1 Catastrophic Event Straight-Time Labor Balancing Account (CESTLBA)

See Table 12-1 above.

12.3.2 Z-Factor Memorandum Account

See Table 12-1 above.

2754 *Id.*, p. 9.

12.3.3 Other Balancing Or Memorandum Accounts

See Table 12-1 above.

13. UPDATE TESTIMONY (EXHIBIT PG&E-33)

13.1 PG&E's Updated Escalation Rates Are Reasonable And Should Be Approved

PG&E's Update Testimony included updated escalation factors based on the Second Quarter 2022 IHS Markit Power Planner Report, which PG&E proposes should be used instead of the pre-pandemic First Quarter 2020 data PG&E used to calculate the revenue requirement in its opening testimony.[2755] The Commission regularly approves GRC Update Testimony based on more recent versions of the IHS Markit Power Planner Report.[2756] Updates for escalation factors have been permitted in the GRCs since 1989.[2757] As the Commission noted in SDG&E and SoCalGas' 2019 GRC, the Commission finds it "appropriate to base labor and non-labor O&M costs on the IHS Markit Global Insight (Global Insight) forecast because Global Insight escalation rates are specific to the utility industry and more accurately reflect [the utilities'] inflationary cost increases."[2758]

13.2 PG&E's Updated Escalation Rates Reflect Current Economic Conditions

TURN acknowledges that the economy has recently experienced high inflation.[2759] It also acknowledges that the Commission regularly approves the use of the most recent IHS Markit Global Insight forecasts to calculate GRC escalation rates to reflect current market

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2755 PG&E Opening Brief, pp. 868-873; PG&E-33, Ch. 2.

2756 The Commission regularly accepts updates based on Global Insight data. See, e.g. D.21-08-036, p. 540; D.21-05-003, p. 12; D.19-09-051, p. 708; D.16-06-054, pp. 160-161; D.14-08-032, pp. 654-661; D.13-05-010, p. 982-983; D.04-07-022, pp. 177-278; D.82-12-055, pp. 3, 9, and 29, 1982 Cal. PUC LEXIS 1209, *13, *23 and *50-51, 10 CPUC 2d 155.

2757 D.89-01-040, p. B-26, 1989 Cal. PUC LEXIS 37, 30 CPUC 2d 576; D.07-07-004, p. A-36.

2758 D.21-05-003, p. 11, citing D.19-09-051, pp. 708-709.

2759 TURN Amended Opening Brief, p. 8.

conditions.[2760] TURN's primary objection to PG&E's use of the updated IHS Markit Report appears to be that the rates have increased due to inflation:

> TURN submits that the Commission should not adopt the escalation factors submitted by PG&E in its Update Testimony. 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.[2761]

"TURN does not dispute that PG&E was *permitted* to update the non-labor escalation factors used in its original GRC filing 'based on the same indexes the party used in its original presentation during hearings.'"[2762] TURN also argues that the Commission is not obligated to accept the update, but offers no authority to support rejection of the update simply because the rates have increased due to inflation. Indeed, the Rate Case Plan specifically contemplates updates because it is anticipated that changes to escalation factors will occur while the case is pending. Using the more recent report that reflects current economic conditions is appropriate and would, consistent with the Commission's recent decision in SoCalGas' and SDG&E's GRC, "more fully capture the impact of Covid-19 to the economy."[2763] TURN itself acknowledged in a filing in SoCalGas' and SDG&E's 2019 GRC that if the Commission is relying on IHS Markit data to establish attrition rates, it should use the most recent report to reflect "current market conditions." TURN opined:

> Suffice it to say, we are living in a time of rapidly changing public health and economic conditions, where the challenges in predicting what the next several years will look like are enormous. To the extent the Commission concludes that the PTY ratemaking mechanism adopted in D.19-09-051 should be continued in

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2760 TURN Amended Opening Brief, p. 27, citing D.21-05-003, p. 2 (Approving for SDG&E's and SoCalGas attrition years the use of "the updated 2020 4th Quarter Global Insight forecast to more fully capture the impact of Covid-19 to the economy.")

2761 TURN Amended Opening Brief, p. 615 (citations omitted).

2762 TURN Amended Opening Brief, p. 614.

2763 D.21-05-003, p. 2.

2022 and 2023, the Commission should ***at least*** require the utilities to update their revenue requirement requests to reflect Global Insight's 2nd Quarter 2020 utility cost forecast. ***Requiring this update would provide escalation factors that reflect Global Insight's consideration of current economic conditions***.[2764]

TURN's argument that the escalation rates in the Second Quarter report are "estimates" that are somehow unreliable is belied by the fact that the 2021 rates are actuals, and the 2022 escalation rates are based in part on actuals, as discussed in PG&E's Opening Brief.[2765] So a considerable portion of the escalation between 2020 and 2023 is already in the books and will not change. The years that follow necessarily are always estimates, but they are estimates based on the best available data at this time. As noted above, the Commission has repeatedly adopted the most recent version of the IHS Markit data as part of a GRC update.

TURN cites irrelevant discussion from two GRC decisions to support its argument that the Commission can arbitrarily refuse PG&E's escalation update to establish a forecast. The portions of the decisions cited by TURN relate to methodologies used to forecast test year costs and not to updated escalation rates.[2766] TURN's reliance on SDG&E's and SoCalGas' 2012 GRC decision, is misplaced. There the utilities provided update testimony to update their cost escalation factors "[a]s contemplated by the Rate Case Plan in D.89-01-040 . . . based on the indexes from Global Insights' 3rd Quarter 2011 Power Planner…."[2767] The Commission approved the utilities' update testimony over the objection of intervenors who proposed to use the CPI to escalate costs instead:

> We have also considered whether Global Insight's utility-specific index is a better indicator of what future utility costs will be, as opposed to using the CPI – Urban

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2764 Comments of The Utility Reform Network on the Phase 2 Scoping Memo, A.17-10-007, (July 20, 2020) p. 8 (emphasis added to final sentence only), <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M344/K014/344014395.PDF> (as of Nov. 18, 2022).

2765 PG&E Opening Brief, pp. 872-873; Tr. Vol 14, 2683:23 to 2686:12, PG&E/Griffes.

2766 See TURN Amended Opening Brief, p. 615, citing D.04-07-022, p. 15 and D.13-05-010, p. 20.

2767 D.13-05-010, p. 976.

> index. Using utility-specific indexes, as well as the union approved wage increases for labor escalation, will provide a better reflection of what utility costs will be. To substitute the CPI – Urban index for the utility-specific index would not accurately reflect the costs that affect the utility industry since the CPI – Urban index only examines the price changes for a basket of goods and services consumed by a typical household. Based on all those considerations, we agree that the Applicants' cost escalation factors . . . should be adopted as the cost escalation factors for the forecasts for test year 2012.[2768]

Notably, while TURN asks the Commission to reject the update, it does not claim that the escalation rates that PG&E originally used from the First Quarter 2020 report are better evidence of escalation rates. The First Quarter 2020 report, of course, does not reflect the "impact of Covid-19 to the economy" and recent increases in inflation. While all IHS Markit Reports necessarily contains estimates, the Commission regularly accepts them, finding that "the Global Insight escalation rates more accurately forecast the inflationary increases for the utility."[2769] In fact, it has stated, the "IHS Global Insight (IHS Global) economic forecasting service . . . is undisputed as a reliable, independent, and accurate source for escalation and return forecasts."[2770] TURN's objection that for some of the years the data is a forecast should be disregarded. The Commission should approve PG&E's Update Testimony which relies on the Second Quarter 2022 IHS Markit data as the best evidence in this proceeding of the impact of inflation during this GRC period on PG&E's base year costs. To provide a more complete evidentiary record, PG&E has also committed to providing as a late-filed exhibit the Q3 2022

2768 D.13-05-010, pp. 982-983.

2769 D.15-11-021, p. 391 (" In adopting the O&M escalation rates, we agree with SCE that the Global Insight escalation rates more accurately forecasts the inflationary increases for the utility. We decline to adopt escalation based on the CPI, as proposed by ORA, or a broad wholesale pricing index, the WPI-IND, as proposed by TURN. We concur with SCE that both the CPI and the WPI-IND reflect price increases for goods and services that are not sufficiently similar to SCE's labor and capital inputs. Since the Global Insight escalation rates are specific to the utility industry, they more accurately reflect SCE's inflationary cost increases. SCE's estimates for other O&M expenses are reasonable.")

2770 D.14-12-082, p. 115 (citation omitted).

and Q4 2022 IHS Reports.[2771] In the alternative, the Commission should use the late-filed IHS Reports as the basis for the escalation update.

13.3 PG&E's Tax Update Is Reasonable And Should Be Approved

PG&E's Update Testimony also included updates for three tax changes: (A) Tax adjustment to comply with Internal Revenue Service Rules; (B) Inflation Reduction Act – related changes; and (C) Gas Transmission Accounting Method Changes.[2772] TURN was the only party to address these issues, and provided testimony solely on the Gas Transmission Accounting Method Changes. The tax changes are discussed in detail in Section 10.2.2 of PG&E's Opening Brief and this Reply Brief.

2771 PG&E Opening Brief, p. 873.

2772 PG&E-33, Ch. 3.

14. MEMORANDUMS OF UNDERSTANDING

14.1 Small Business Utility Advocates

No party disputed PG&E's Memorandum of Understanding with SBUA to support PG&E's small business customers during the 2023 GRC period. Please see PG&E's Opening Brief Section 14.1.

14.2 Center For Accessible Technology

No party disputed PG&E's Memorandum of Understanding with CforAT to improve accessibility for customers throughout PG&E's service area. Please see PG&E's Opening Brief Section 14.2.

14.3 National Diversity Coalition

No party disputed PG&E's Memorandum of Understanding with NDC to leverage new pathways for outreach and education and supporting economic opportunities for diverse communities. Please see PG&E's Opening Brief Section 14.3.

14.4 Engineers And Scientists Of California Local 20

No party disputed PG&E's Memorandum of Understanding with Engineering and Scientists of California Local 20 regarding PG&E Academy training for engineers during the 2023 GRC period. Please see PG&E's Opening Brief Section 14.4.

15. CONCLUSION

For the reasons stated herein and in PG&E's Opening Brief, PG&E respectfully requests the Commission approve its 2023 GRC application with the updated revenue requirement included herein as Appendix A.

Respectfully submitted,

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Dated: December 9, 2022

Appendix A
Test-Year 2023 Forecast Summaries

The tables below show PG&E's test-year 2023 JCE expense forecasts, capital forecasts, department costs, and companywide expense forecast and PG&E's Reply Brief forecasts that account for settlements, stipulations, and PG&E's undergrounding forecast adjustment.

- Table 1 – PG&E's 2023 revenue requirement.
- Table 2 – PG&E's 2023 post-test year revenue requirement.
- Table 3 – PG&E's 2023 final expense forecast by exhibit.
- Table 4 – PG&E's 2023 final capital forecast by exhibit.
- Table 5 – PG&E's 2023 final department cost forecast.
- Table 6 – PG&E's 2023 final companywide cost forecast.

Table 1 – PG&E's Forecast Revenue Requirement[(a)]
(Millions of Nominal Dollars)

Description	2022 Authorized Revenue[(a)]	2023 GRC Forecast	2023 Increase Over 2022	2024 GRC Forecast	2025 GRC Forecast	2026 GRC Forecast
PG&E's Joint Comparison Exhibit Forecast	$12,214	$16,181	$3,967	$17,250	$18,100	$18,768
Wildfire Insurance Settlement[(b)]		$(259)	$(259)	$(281)	$(482)	$(685)
Other A&G Stipulations[(c)]		$(3)	$(3)	$(4)	$(4)	$(4)
Information Technology Stipulation[(d)]		$(42)	$(42)	$(45)	$(48)	$(50)
Energy Supply Stipulations[(e)]		$(21)	$(21)	$(10)	$(8)	$(13)
Gas Connects Stipulation[(f)]		$(4)	$(4)	$(14)	$(24)	$(34)
System Hardening Forecast Adjustment[(g)]		$(34)	$(34)	$(153)	$(352)	$(554)
Total Changes		$(362)	$(362)	$(507)	$(919)	$(1,341)
PG&E Reply Brief Forecast[(h)]	$12,214	$15,819	$3,605	$16,743	$17,181	$17,427

(a) PG&E-64 (Second Amended), p. 1-2, Table 1-1; Amounts shown include the Updated Escalation Factors in PG&E-33.
(b) Reflects the Proposed Settlement on Wildfire Insurance filed October 7, 2022.
(c) Reflects the stipulation of TURN, Cal Advocates, and PG&E resolve all contested Administrative and General issues included in Appendix G of PG&E's Opening Brief.
(d) Reflects the stipulation of Cal Advocates, TURN and PG&E on Enterprise Data Management and Information Technology Forecast included in Appendix F of PG&E's Opening Brief.
(e) Reflects the stipulation of TURN and PG&E resolving disputed Energy Supply issues included in Appendix E of PG&E's Opening Brief and the stipulation of the Cal Advocates and PG&E for the purposes of resolving contested Energy Supply issues included in Appendix B of PG&E's Reply Brief.
(f) Reflects the stipulation of TURN and PG&E on Gas Distribution capital New Business Program (MWC 29) included in Appendix C of PG&E's Reply Brief.
(g) Reflects PG&E's adjusted forecast for MAT 08W. See PG&E's Reply Brief, Section 4.1, Table 4-1.
(h) Differences due to rounding.

Table 2 – Post-Test Year Revenue Requirement (Millions of Nominal Dollars)				
Functional Area	**2023 Increase Over Adopted**	**2024>2023**	**2025>2024**	**2026>2025**
Electric Distribution	$2,878	$376	$409	$470
Gas Distribution	$513	$240	$297	$304
Electric Generation	$(51)	$8	$(418)	$(696)
Gas Transmission and Storage	$264	$299	$151	$169
Total[a]	$3,605	$924	$438	$247
(a) Differences due to rounding.				

Table 3 - Test-Year 2023 Expense Forecasts (Thousands of Nominal Dollars)			
Exhibit	**JCE Final Forecast [a]**	**Reply Brief Forecast**	**Difference**
Gas Operations	$1,316,806	$1,316,806	$0
Electric Distribution	$2,597,136	$2,597,136	$0
Energy Supply[b]	$633,475	$616,846	$(16,629)
Customer and Communications	$386,680	$386,680	$0
Shared Services and Information Technology[c]	$790,110	$746,245	$(43,865)
Total	$5,724,207	$5,663,713	$(60,494)

(a) PG&E-64 (Second Amended), Chapter 3, Table 3A-1, Column "PG&E (with Sep 6 Non-Labor Escalation Adjustment)."

(b) Reflects the stipulation of TURN and PG&E resolving disputed Energy Supply issues included in Appendix E of PG&E's Opening Brief and the stipulation of the Cal Advocates and PG&E for the purposes of resolving contested Energy Supply issues included in Appendix B of PG&E's Reply Brief.

(c) Reflects the stipulation of Cal Advocates, TURN and PG&E on Enterprise Data Management and Information Technology Forecast included in Appendix F of PG&E's Opening Brief.

Table 4 - Test-Year 2023 Capital Forecasts (Thousands of Nominal Dollars)			
Exhibit	**JCE Final Forecast [a]**	**Reply Brief Forecast**	**Difference**
Gas Operations[b]	$2,705,212	$2,635,846	$(69,366)
Electric Distribution[c]	$5,117,678	$4,730,135	$(387,543)
Energy Supply[d]	$463,095	$461,565	$(1,530)
Customer and Communications	$338,811	$338,811	$0
Shared Services and Information Technology[e]	$1,595,232	$1,587,971	$(7,261)
Human Resource	$1,210	$1,210	$0
Administrative and General[f]	$3,025	$3,025	$0
Total	$10,224,263	$9,758,563	$(465,700)

(a) PG&E-64 (Second Amended), Chapter 3, Table 3B-1. Column "PG&E (with Sep 6 Capital Escalation Adjustment)."

(b) Reflects the stipulation of TURN and PG&E on Gas Distribution capital New Business Program (MWC 29) included in Appendix C of PG&E's Reply Brief.

(c) Reflects PG&E's adjusted forecast for MAT 08W. See PG&E's Reply Brief, Section 4.1, Table 4-1.

(d) Reflects the stipulation of TURN and PG&E resolving disputed Energy Supply issues included in Appendix E of PG&E's Opening Brief and the stipulation of the Cal Advocates and PG&E for the purposes of resolving contested Energy Supply issues included in Appendix B of PG&E's Reply Brief.

(e) Reflects the stipulation of Cal Advocates, TURN and PG&E on Enterprise Data Management and Information Technology Forecast included in Appendix F of PG&E's Opening Brief.

(f) Reflects the stipulation of TURN, Cal Advocates, and PG&E resolve all contested Administrative and General issues included in Appendix G of PG&E's Opening Brief.

Table 5 - Test-Year 2023 Corporate Services Department Costs Including IT (Thousands of Nominal Dollars)			
Exhibit	**JCE Final Forecast [a]**	**Reply Brief Forecast**	**Difference**
Human Resources	$88,993	$88,993	$0
Administrative and General (PG&E-9, Ch.2-8)[b]	$159,015	$158,854	$(161)
Total	$248,008	$247,847	$(161)

(a) PG&E-64 (Second Amended), Chapter 3, Table 3C-1, Column "PG&E (with Sep 6 Non-Labor Escalation Adjustment).

(b) Reflects the stipulation of TURN, Cal Advocates, and PG&E to resolve all contested Administrative and General issues included in Appendix G of PG&E's Opening Brief.

Table 6 - Test-Year 2023 Companywide Expenses (Thousands of Nominal Dollars)			
Exhibit	**JCE Final Forecast [a]**	**Reply Brief Forecast**	**Difference**
Shared Services and Information Technology (PG&E-7, Ch. 1A)	$156,420	$156,420	$0
Human Resources (PG&E-8, Ch. 3-5)	$945,628	$945,628	$0
Administrative and General (PG&E-9, Ch. 3-7)[b]	$956,398	$645,020	$(311,377)
Total	$2,058,445	$1,747,068	$(311,377)

(a) PG&E-64 (Second Amended), Chapter 3, Table 3C-1, Column "PG&E (with Sep 6 Non-Labor Escalation Adjustment).

(b) Reflects the Wildfire Insurance Settlement and the stipulation of TURN, Cal Advocates, and PG&E resolve all contested Administrative and General issues included in Appendix G of PG&E's Opening Brief.

Appendix B

STIPULATION OF CAL ADVOCATES AND PG&E ON ENERGY SUPPLY ISSUES
A.21-06-021
November 21, 2022

Introduction

The Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and Pacific Gas & Electric (PG&E) submit the following stipulation for the purposes of resolving contested Energy Supply issues in this proceeding.

Cal Advocates and PG&E agree that this stipulation reflects a complete resolution of disputed Energy Supply issues except for attrition, depreciation and other topics not addressed in Exhibit PG&E-5. In exchange for supporting this stipulation, Cal Advocates and PG&E agree not to oppose all undisputed energy supply forecasts and energy supply proposals not specifically addressed in this stipulation (except for attrition, depreciation and other topics not addressed in Exhibit PG&E-5).

For purposes of determining final values for each of the categories, the parties agree that the final escalation amounts adopted by the Commission should apply to any identified values in the stipulation.

The stipulation reflects a compromise of disputed litigation positions on a range of Energy Supply issues addressed by the parties and constitutes an integrated agreement that should be approved in its entirety without modification. The parties request that the Commission approve the provisions of this stipulation instead of any contrary positions articulated in prepared testimony.

The Commission should find that this stipulation is reasonable in light of the testimony submitted, consistent with law, and in the public interest.

I. Hydro Operations

The parties agree that it is reasonable to use a 2021 hydro capital expenditure forecast of $207.891 million which is consistent with 2021 recorded capital expenditures. This forecast will not be escalated. PG&E's agreement to use 2021 recorded data for hydro capital is not precedent setting for other GRC exhibits or proceedings.

The parties agree that the provision in the Energy Supply Stipulation between PG&E and TURN regarding the change in operative date for the UNFFR License Conditions project (and all HLBA-related projects with operative dates in December 2026) from December 2026 to January 2027 satisfies Cal Advocates proposal to reduce PG&E’s 2022 capital expenditure forecast. The parties agree that PG&E’s 2022 hydro capital expenditure forecast of $227.948 million is reasonable.

II. Electric Procurement Administration

The parties agree that a TY 2023 forecast of $43.786 million for Electric Procurement Administration costs is reasonable.

III. All Other Energy Supply Forecasts

Cal Advocates agrees that, with the exception of issues resolved in Sections I and II, the TY 2023 expense forecasts and 2023-2026 capital forecasts agreed to in the Energy Supply Stipulation between PG&E and TURN dated November 1, 2022, fully resolve all of Cal Advocates disputed issues with PG&E's Energy Supply exhibit.

APPENDIX C

STIPULATION ON
GAS DISTRIBUTION CAPITAL NEW BUSINESS PROGRAM (MWC 29)
A.21-06-021
December 2, 2022

Introduction

The Utility Reform Network (TURN) and Pacific Gas and Electric Company (PG&E) (the Parties) submit the following stipulation for the purposes of resolving the forecast for the Gas Distribution Capital New Business Program (MWC 29) (Stipulation).

The Parties request that the Commission approve the provisions of this stipulation instead of any contrary positions articulated in their respective testimony or opening briefs.

The Commission should find that this stipulation is reasonable in light of the Parties' testimony and opening briefs, consistent with law, and in the public interest.

Background

PG&E originally forecast $126.209 million in capital expenditures for the Gas Distribution Capital New Business Program (MWC 29) in 2023.[1]

In its opening testimony TURN recommended a $16.3 million reduction to the MWC 29 forecast based on its disagreement with the permit modelling conducted by PG&E's third party consultant. TURN also recommended further reductions to MWC 29 if the Commission modified or eliminated gas line extension subsidies in rulemaking R.19-01-011 Phase III.[2]

Subsequently, on September 15, 2022 the Commission issued D. 22-09-026 which eliminated the gas line extension allowances as of July 1, 2023 (the Gas Allowance Decision).[3] The Commission also approved an application process after July 1, 2023 for specific, unique non-residential projects where a gas line subsidy may still be warranted.[4]

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1 PG&E Opening Brief, p. 346, Table 3-73.

2 PG&E Opening Brief, pp. 346-347; Ex. TURN-08, Section III.

3 *Order Instituting Rulemaking Regarding Building Decarbonization*, R.19-01-011 (Jan. 31, 2019). Phase III Decision Eliminating Gas Line Extension Allowances, Ten Year Refundable Payment Option, And Fifty Percent Discount Payment Option Under Gas Line Extension Rules. D.22-09-026.

4 *Id.*, Ordering Paragraphs 2 and 3.

In its Opening Brief, PG&E proposed a revised 2023 forecast for MWC 29 of $85.4 million to reflect the anticipated impact of the Gas Allowance Decision. PG&E also proposed that the revised forecast for MWC 29 should be subject to a one-way balancing account.[5]

In its Opening Brief, TURN proposed that the Commission should protect ratepayers from overpaying for gas new connections by either: (1) Directing PG&E to submit a Tier 2 compliance advice letter on August 1, 2023, that revises the authorized GRC forecast for GD New Connections costs for 2023-2026 based on applications submitted prior to the July 1, 2023 cutoff, or (2) Reducing PG&E's 2023 forecast for MWC 29 by 50% and directing PG&E to create a new one-way balancing account to track actual expenditures on GD New Connections over the four-year GRC period, with any overcollection returned to ratepayers.[6] TURN also continued to recommend that PG&E's Residential New Connections forecast should additionally be reduced to reflect a more reasonable forecast of building permits.[7]

Terms of Stipulation

TURN and PG&E agree 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 4-year 2023-2026 2023 GRC 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 GRC cycle, with any underspending returned to ratepayers. Any spending above the forecast will be reviewed as part of PG&E's 2027 GRC 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 GRC 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 GRC 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 (Exhibit TURN-08, Section III.A).

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5 PG&E Opening Brief, Section 3.13.2.1, p. 348.

6 TURN Opening Brief, Section 3.13.1.2, p. 337.

7 TURN Opening Brief, Section 3.13.1.1, p. 337.