CPUC Docket: A.25-05-009
Exhibit Number: TURN-03
Witness: Jalal Awan

PREPARED TESTIMONY OF
JALAL AWAN, PH.D.
ADDRESSING GAS DISTRIBUTION MAINS AND SERVICES – PIPELINE REPLACEMENT PROGRAMS

Submitted on Behalf of

THE UTILITY REFORM NETWORK

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February 13, 2026

Table of Contents

LIST OF FIGURES

LIST OF TABLES

PREPARED TESTIMONY OF JALAL AWAN

ADDRESSING GAS DISTRIBUTION MAINS AND SERVICES

I. INTRODUCTION

A. Summary of Witness Qualifications

I am an Energy and Climate Policy Analyst at The Utility Reform Network (TURN) since November 2023, where I analyze utility cost forecasts, risk datasets, and statistical models to support data-driven positions in California Public Utilities Commission proceedings, including but not limited to, Southern California Edison's 2025 General Rate Case (A.23-05-010), PG&E's 2024 RAMP Application (A.24-05-008), PG&E's Gas Advanced Metering Infrastructure Application (A.24-03-011), and the Long Term Gas Planning OIR (R.24-09-012). I have sponsored testimony and conducted discovery on behalf of TURN, including on utility risk-modeling methodologies, regression-based demand forecasting, and cost-effectiveness evaluation of proposed capital programs.

Prior to TURN, I was an Assistant Policy Analyst at the RAND Corporation (2017–2023), where I developed and evaluated quantitative risk and forecasting frameworks, including regression-based models, time-series and geospatial analytics, sensor calibration models, and performance-measurement tools for public-sector decisionmaking. I have 5 years hands-on experience as a projects engineer at a large combined-cycle gas power plant, where I was involved in risk-informed, cost-effective preventive and corrective maintenance planning.

I hold a Ph.D. and M.Phil. in Policy Analysis (quantitative methods) from the Pardee RAND Graduate School, an M.S. in Energy Systems from the University of Southern California (Viterbi School of Engineering), and a B.E. in Electrical Engineering. I am a certified Six Sigma Green Belt and hold USGBC LEED certification. My research portfolio includes quantitative risk assessment, risk evaluation frameworks for emerging technologies, asset management, and statistical modeling—skills directly applicable to evaluating gas distribution pipeline replacement programs, likelihood-of-failure and consequence-of-failure analyses.

B. Summary of Recent Litigation Concerning Pipe Replacement

A short summary of recent litigation concerning plastic pipe replacement programs in California helps highlight certain key issues. In PG&E's last rate case application 21-06-021,[1] PG&E proposed to increase the replacement rate for Aldyl-A plastic pipe from 139 miles per year to an average of 178 miles per year for 2023-2026. TURN retained Mr. John Sugar, an expert economist and energy consultant, to address this issue. Mr. Sugar evaluated various risk reports and PG&E's internal leak data, and concluded that PG&E should focus on replacing Aldyl-A pipe installed before 1975 to account for the material defects of early Aldyl-A pipe (manufactured through 1972), and the much higher leak rate of pipe installed before 1975 on PG&E's system.[2] Mr. Sugar recommended PG&E replace about 60 miles of plastic pipe per year. The Commission rejected both the TURN and PG&E recommendations and concluded that "continuing the replacement rate of previous years is a balanced approach" to addressing the risks posed by Aldyl-A pipe as compared to other risks to PG&E infrastructure.[3]

In its most recent rate case application 22-05-015, SoCalGas similarly requested to increase its plastic pipe replacement from 78 to 136 miles per year.[4] In that case, TURN retained Mr. Rod Walker, a veteran gas distribution engineer, to evaluate SoCalGas's analyses and arguments. Mr. Walker evaluated both internal SoCalGas data, as well as national data and PHMSA bulletins, and concluded that there was no basis for any pre-emptive replacement of Aldyl-A pipe. Mr. Walker also concluded that SoCalGas should expand its replacement of unprotected steel pipe. The Commission agreed with TURN that SoCalGas had not demonstrated a need for plastic pipe replacement, and authorized only $14.3 million in capital for 2024 to replace just the pre-1973 plastic pipe, rather than the $232 million per year requested by SoCalGas.[5]

In this case, I closely analyzed the same type of internal data that were considered by Mr. Sugar and Mr. Walker. Furthermore, I also obtained and analyzed the results of PG&E's own DIMP risk model – the "RiskFinder" model. I had worked previously as TURN's expert on risk assessment in PG&E's 2024 RAMP Application 24-05-008, and have expertise in evaluating large data sets

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[1] See, D.23-11-069, Section 3.3.4.3 and 3.3.4.4.
[2] The relevant portion of Exhibit TURN-06 is included in the Attachments Exhibits.
[3] D.23-11-069, pp. 75-76.
[4] See, D.24-12-074, Sections 13.1.2.1 and 13.1.2.3.
[5] D.24-12-074, pp. 253, 258.

and risk analyses results. From all these analyses, I reached similar conclusions as TURN's prior experts; but I also discovered that PG&E fails to use the results of its own DIMP model to plan the scope and pace of its pipeline replacement work. PG&E's resulting proposal is thus not risk-based, but rather uses fairly arbitrary targets that do not optimize risk reduction in a cost-effective manner.

II. SUMMARY OF PG&E REQUEST AND TURN RECOMMENDATIONS

A. Summary of PG&E's Request for Pipeline Replacement Programs (Capital, MATs 14A, 14D, and 50A)

In Exhibit (PG&E-3), Chapter 4, PG&E seeks approval of substantial and rapidly increasing capital spending for gas distribution pipeline replacement under three programs: the Gas Pipeline Replacement Program (GPRP, MAT 14A), the Plastic Pipe Replacement Program (MAT 14D), and the Reliability Main Replacement Program (MAT 50A). Together, these programs constitute the core of PG&E's proposed gas distribution capital spending for the 2027 GRC cycle.

PG&E explains that its Distribution Mains and Services (DMS) asset family includes approximately 45,200 miles of distribution mains and nearly 3.7 million gas services, serving approximately 4.8 million customers (Ex. PG&E-3, p. 4-2, lines 29-31).[6] Within this asset family, pipeline replacement programs are intended to mitigate safety and reliability risks identified through PG&E's Distribution Integrity Management Program (DIMP).

PG&E's Chapter 4 outlines three pipeline replacement programs:

MAT 14A – Gas Pipeline Replacement Program (GPRP): Targets pre-1941 steel pipe, requesting 25 miles per year at a forecast unit cost of $5.7 million per mile. (PG&E-3, p. 4-26, lines 9-10)

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[6] Of PG&E's approximately 45,200 miles of distribution mains, polyethylene (plastic) and steel account for 24,789 miles (55%) and 20,335 miles (45%), respectively. Steel and wrought iron pipe comprise less than 1% of the total and are therefore excluded from mileage-based calculations. Source: GRC-2027-PhI_DR_TURN_006-Q006Atch01

MAT 14D – Plastic Pipe Replacement Program: Targets pre-1985 Aldyl-A plastic pipe and similar materials, requesting 139 miles per year at a forecast unit cost of $4.1 to $4.2 million per mile. (PG&E-3, p. 4-26, lines 10-11)

MAT 50A – Reliability Main Replacement Program: Proposes to increase pace from 15 to 30 miles per year for pipe not covered by the above programs, at a forecast unit cost of $5.6 to $6.5 million per mile. (PG&E-3, p. 4-26, lines 12-13)

All three programs include replacement of associated services when mains are replaced (id., lines 8-9).

PG&E proposes to continue, and in some cases significantly expand, the replacement pace adopted in the 2023 GRC.

Table 4-6 of Exhibit PG&E-3 shows that PG&E's capital forecast for these programs increases sharply over the GRC period and beyond. Relative to the 2023 GRC, average annual capital in the 2027 GRC forecast increases by approximately 47 percent for steel pipeline replacement, 57 percent for plastic pipe replacement, and 365 percent for reliability main replacement. Total spending on these three programs increases from $499 million in 2023 to $885 million in 2027, an increase of approximately 77 percent.

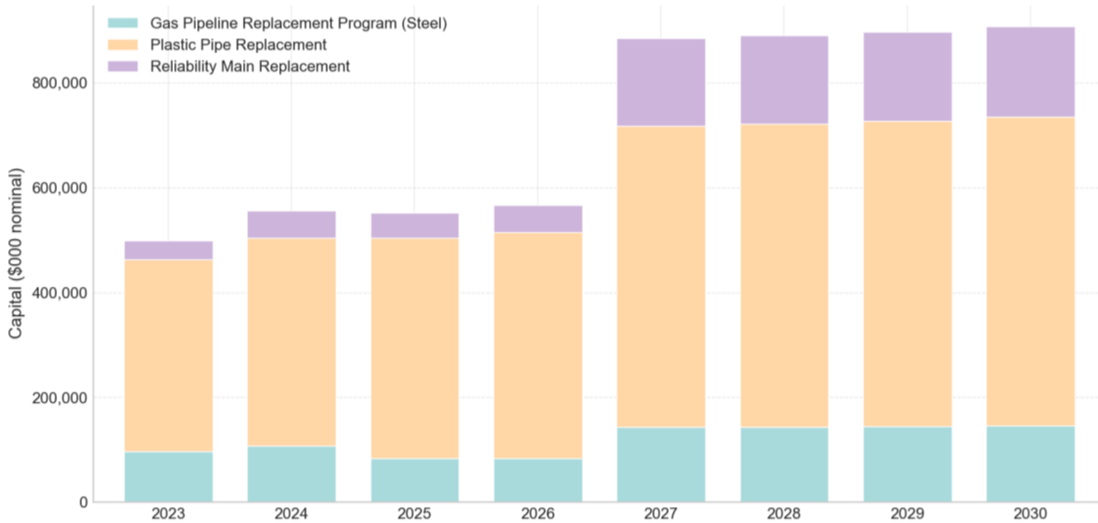

Figure 1 Pipeline Replacement Programs (MAT14A, 14D, and 50A) capital by year (2023 GRC vs. 2027 GRC)

Despite these large increases in spending, PG&E acknowledges that the cost-benefit ratios (CBRs) for these programs remain extremely low. As shown in Table 4-6, PG&E reports CBRs of **0.06 for steel pipeline replacement (MAT 14A)**, **0.03 for plastic pipe replacement (MAT 14D)**, and **0.005 for reliability main replacement (MAT 50A)**. These ratios indicate that for every dollar PG&E spends on these programs, ratepayers receive approximately **6 cents, 3 cents, and one-half of one cent**, respectively, in quantified risk-reduction benefits. By the Commission's own cost-effectiveness standards, these programs fail fundamental tests of prudence.

B. Summary of TURN's Recommendations

As detailed in Section V, TURN recommends a significant reduction in the plastic pipe replacement program, as well as changes to the reliability main replacement program. TURN provides three recommendations.

First, TURN recommends calibrating replacement mileage to demonstrated per-mile risk using PG&E's own RiskFinder results (**Recommendation 1**). RiskFinder shows that steel pipelines are consistently riskier than plastic on a per-mile basis, including pre-1985 plastic. Aligning replacement pace with this risk hierarchy supports annual replacement of 25 miles of pre-1941 steel, 85 miles of pre-1985 plastic, and 15 miles of reliability mains. Under TURN's proposed mileage (and PG&E's unit cost assumptions), this risk-aligned mileage reduces 2027 capital spending for the three replacement programs from approximately **$885 million to $578 million**, a reduction of about **35%**.

Second, TURN recommends that the Commission correct PG&E's inflated unit cost forecasts for pipeline replacement (**Recommendation 2**). PG&E's proposed 2027–2030 unit costs exceed both PG&E's own 2021–2024 recorded weighted average cost of $3.87 million per mile and unit costs of comparable California gas utilities. TURN proposes adopting PG&E's recorded historical unit costs as the baseline, appropriately escalated and differentiated by material type, resulting in unit costs approximately 6–9% lower than PG&E's forecasts over the 2027–2030 period. Using TURN's mileage (and TURN's unit cost assumptions) reduces PG&E's 2027 forecast from $885million to **$541 million, a reduction of about 39%.** TURN recommends that the Commission adopt this figure as the test year capital expenditure for the three pipe replacement programs, as detailed in the table below.

Table 1: TURN Recommendation 1 and 2 (TY 2027)

Program (MAT)	TURN Miles Rec 1	PG&E Miles	PG&E $/mile	TURN $/mile Rec 2	PG&E Unit Cost / TURN Mileage ($M) TURN Rec 1	TURN Unit Cost & Mileage ($M) TURN Rec 1&2	PG&E Unit Cost & Mileage ($M)	% Diff (TURN Rec 1 & 2 vs PG&E)
MAT 14A (Steel)	25	25	$5.72	$5.35	$142.90	$133.85	142.9	-6.33%
MAT 14D (Plastic)	85	139	$4.13	$3.87	$351.22	$329.04	574.4	-42.72%
MAT 50A (Reliability)	15	30	$5.58	$5.23	$83.70	$78.41	167.4	-53.16%
Total	65	194	—	—	**$577.82**	**$541.29**	**$884.70**	-38.82%

However, the Commission should adopt and apply the lower unit costs irrespective of which annual replacement mileage forecasts it authorizes.

Third, TURN recommends that the Commission direct PG&E, in its next (currently scheduled as 2031) GRC Application, to base the pipeline replacement forecast on its own Distribution Integrity Management Program (DIMP) outputs, rather than predetermined mileage targets carried forward from prior GRCs (**Recommendation 3**). PG&E has acknowledged that none of the 3,545 DIMP mitigation analysis jobs (approximately 49,653 segments and 2,000 miles) are included in its 2027 GRC forecast, effectively sidelining risk-based prioritization in favor of an administrative objective to retire all pre-1985 plastic by 2030. For PG&E's 2031 GRC application period (2031-2034), TURN recommends the Commission require a DIMP-informed, segment-level replacement plan, including sub-decade vintage analysis, geographic risk disaggregation, and post-implementation risk verification to ensure projected risk reductions are realized.

III. SIGNIFICANT PROBLEMS WITH PG&E'S JUSTIFICATIONS FOR ITS REPLACEMENT PROGRAMS

A. A Misreliance on 49 CFR 192

PG&E briefly acknowledges the prior history of litigation in the last rate case, but claims once again that limiting program scope would violate federal regulatory requirements:

> "PG&E acknowledges that in prior rate cases parties have been critical of the fact that PG&E's forecast, for the most part, does not identify the specific pipe segments to be replaced...PG&E is aware that in prior rate cases parties suggested that PG&E consider evaluating pre-1976 plastic and pre-1924 steel main separately from pre-1985 plastic and pre-1941 steel. *PG&E believes limiting the pipe replacement programs based on installation year and leak rates would result in non-compliance with 49 CFR 192, subpart P.*" (PG&E-3, p. 4-27, lines 22-24;emphasis added)

This claim appears inconsistent with both the law and PG&E's own proposal, given that PG&E produces extensive DIMP and RiskFinder risk analyses but explicitly declines to use those same analyses to inform its 2027–2030 pipeline replacement mileage forecast. 49 CFR 192, Subpart P requires utilities to "identify threats, evaluate and rank risk through the evaluation of the likelihood and consequence of failure of each threat, and then require the identification and implementation of measures to address risk." (PG&E-3, p. 4-27, lines 13-15) The regulation mandates risk-based prioritization, and subsequent replacement. It does not prohibit granular analysis; in fact, it requires it.

PHMSA's September 2023 Notice of Proposed Rulemaking proposes to amend 49 CFR § 192.1007(d) to require operators, when identifying and implementing DIMP mitigation measures, to "specifically account for risks associated with the age of the pipe, the age of the system, the presence of pipes with known issues, and over pressurization of low-pressure distribution systems".[7] PHMSA further emphasizes that proper DIMP implementation should drive replacement of higher-risk infrastructure, while cautioning that replacement itself carries safety and environmental risks and must be balanced against lower-risk alternatives such as pressure-control upgrades, slam-shut devices, telemetered monitoring, and improved records.[8] PHMSA thus mandates risk-specific mitigation, not undifferentiated mileage targets (which paradoxically entail inherent risk)—particularly where operating pressures are low and do not support across-the-board replacement.[9] Such an approach is not consistent with PG&E's blanket, pace-based replacement strategy.

Indeed, PG&E's own proposal underscores the arbitrariness of its vintage cutoffs. PG&E targets pre-1985 Aldyl-A pipe, yet its system contains a comparable quantity of Aldyl-A installed after 1985. The 1985 cutoff is justified by changes in plastic material properties that reduced slow crack growth risk, but Commission analyses show that multiple material changes occurred across different years, each associated with materially different failure characteristics.[10] PG&E offers no principled basis for privileging the 1985 breakpoint while ignoring other documented material transitions that also affect leak and failure risk.

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[7] PHMSA NPRM, Docket No. PHMSA-2021-0046, § III.c, PHMSA's Proposal To Amend § 192.1007(d)—DIMP—Identify and Implement Measures To Address Risks, available at https://www.regulations.gov/document/PHMSA-2021-0046-0014

[8] PHMSA NPRM, Docket No. PHMSA-2021-0046, § III.b, Need for Change—DIMP—Identify and Implement Measures To Address Risks, available at https://www.regulations.gov/document/PHMSA-2021-0046-0014

[9] PG&E's pressure factor in its "Consequence of Failure" calculation(s) in the RiskFinder model distinguishes only between >25 psig (high pressure) and ≤12 (low pressure) producing a narrow consequence spread that does not meaningfully differentiate lower-stress operating conditions (30-40 psig) documented by the Commission as substantially increasing the Mean Time To Failure (MTTF) i.e. reducing overall RoF.[9]

[10] CPUC, *Hazard Analysis and Mitigation Report (Aldyl A Polyethylene Gas Pipelines)*, June 2014, Table 1, p. 8 and Table 2, p. 12, note 1. The table shows that a sub-decade-based cohorts (e.g., pre-1970, 1970–1975, 1976–1983, 1984–1988, post-1988), aligned to year of manufacture and reasonably lagged by installation year, provide a more risk-informed replacement framework. Breaking plastic into staggered vintages preserves known material-performance differences, avoids averaging high- and low-risk pipe together, and ties replacement decisions to demonstrated degradation mechanisms rather than arbitrary cutoffs.

B. The Marginal Risk Problem: How PG&E's Broad Age-Based Cohorts Obscure Addressable Risk

PG&E's defense of its two broad vintage cutoffs for plastic and steel pipelines rests on a statement that reveals the flaw in its methodology:

> "Simply stated, while pre-1976 plastic may, *on average*, be higher risk than 1976-1984 plastic, and pre-1924 steel may, *on average*, be higher risk than 1925-1940 steel, *some 1976-1984 plastic is riskier than some pre-1976 plastic, and some 1924-1940 steel is riskier than some pre-1924 steel.*" (PG&E-3, p. 4-28, lines 5-8; emphasis added)

This acknowledgment of within-cohort variation is precisely what necessitates stricter, and not overly broad, age-based cohorts. PG&E's blanket pre-1985 and pre-1941 cutoffs commit a fundamental analytical error: they treat heterogeneous populations as homogeneous. When PG&E cites within-cohort variation—acknowledging that "some 1976-1984 plastic is riskier than some pre-1976 plastic"—it unwittingly exposes the flaw in its own approach. The existence of within-cohort variation means that *average* risk for the entire pre-1985 cohort (0.08 leaks/mile/year) masks a vastly different marginal risk profile: the 1967–1971 vintage exhibits 0.15 leaks/mile/year—nearly twice the average of the pre-1985 cohort.[11] Replacing based on a pre-1985 average subsequently targets 3,384 miles of total aldyl-A pipeline with below-average risk in order to reach 96 miles of genuinely high-risk 1967-1971 pipe. Marginal risk analysis—focusing replacement capital on the demonstrably riskiest sub-decade cohorts (i.e. 1967–1971)—would achieve a similar safety leak rate reduction per mile while targeting about 2% of total aldyl-A mains compared to almost 80% of mileage PG&E intends to target using its pre-1985 cutoff.

For TY 2027 alone, PG&E proposes to replace roughly 194 miles of mains across MAT 14A, MAT 14D, and MAT 50A, amounting to nearly $900 million in capital spending; yet this aggregate mileage is not derived from any RiskFinder or DIMP prioritization, but instead reflect a continuation of an internally determined, pace-based replacement target.

[11] GRC-2027-PhI_DR_TURN_006-Q007Atch01

C. The Cost-Effectiveness Problem

PG&E's pipeline replacement programs carry Cost-Benefit Ratios (CBRs) far below cost-effectiveness thresholds:

- MAT 14A (Steel GPRP): CBR = 0.06
- MAT 14D (Plastic): CBR = 0.03
- MAT 50A (Reliability Main): CBR = 0.005

(PG&E-03, p. 4-38, Table 4-6, Risk Mitigation and Control Programs)

These ratios mean that for every dollar spent, ratepayers receive between half a cent and six cents in quantified risk reduction benefit. By any standard of utility prudence, these programs fail basic cost-effectiveness tests.

PG&E's response is revealing: "Though the modeling performed in connection with the RAMP proceeding has assigned these programs relatively low CBRs, the pipe to be replaced has substantial risk, as identified by the industry as a whole, by experts at the CPUC, and by PG&E's own experts." (PG&E-3, p. 4-26, lines 16-20)

This inverts the burden of proof. When CBRs are this low, PG&E cannot simply assert expert consensus and expect ratepayers to fund the work.[12]

TURN addresses these deficiencies and provides more specific recommendations below.

D. PG&E's Replacement Decisions Are Driven by Pre-Determined Mileage Targets, Not Risk

PG&E's pipeline replacement forecasts for MATs 14A, 14D, and 50A are not derived from quantified, segment-level risk analysis, but are instead anchored to pre-determined mileage targets carried forward from the 2023 GRC, with risk models applied only after the fact.[13] PG&E

[12] Here, PG&E appears to reference the 2014 CPUC Hazard Analysis & Mitigation Report, which in no way, suggests wholesale mains replacement at the pace proposed by PG&E.

[13] This is despite PG&E's substantial and ongoing investment in risk modeling itself: PG&E recorded an average of approximately $7.6 million per year in 2022–2024 and forecasts approximately $6.5 million per year **in** 2025–2030

admits that DIMP risk results are not used to develop the forecasts for these programs because "the specific projects to be executed are unknown at the time of the 2027 GRC filing," and that DIMP instead informs only near-term (in-year to two-year) project selection.[14] For MATs 14A and 14D, PG&E further states that the "proposed pace" was selected because it "continues" the pace adopted in the 2023 GRC, not because its latest DIMP model run identified a different or more targeted set of assets.[15] Replacement mileage is therefore the starting point, not the outcome, of risk prioritization.

This approach is reinforced by PG&E's explicit (internal) policy objective to "achieve a removal rate of pre-1985 pipe that limits asset age to 100 years by 2030".[16] That age-based target—applied across an asset family comprising 45,200 miles of mains and nearly 3.7 million gas services—largely drives forecasted replacement volumes, for the 2027 GRC period (and beyond), rather than disaggregated evidence of leak rates or failure risk.[17]

Moreover, the mean or average projected failure time for susceptible or lower ductile inner wall (LDIW) Aldyl "A" pipe at 70°F /60 psig is 171 years. that Furthermore, there is a 95% probability that the failure time will occur between 90 years and 325 years.[18] Tables 5 and 6 of the Commission's *Hazard Analysis & Mitigation Report* show that operating pressure is a primary driver of polyethylene pipe failure risk. For 2-inch Aldyl A pipe at 70°F, lower pressures are associated with much *longer* mean times to failure, with projected lifetimes reaching ~115 years at 40 psig.[19] Moreover, PG&E's mains pressure profile indicates that more than half of its polyethylene mains operate below 55 psig, placing a large portion of its Aldyl A system in lower-

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for Risk Model Development, yet still does not use DIMP risk outputs to develop MAT 14A, 14D, or 50A replacement forecasts (GRC-2027-PhI_DR_CalAdvocates_002-Q001_832827Atch01; Ex. PG&E-3, WP 4-17, Table 4-13, Line 1).

[14] PG&E Response to TURN_062_Q001, subpart a, Nov. 25, 2025. There is no means to confirm how/if DIMP results are even used in near-term pipeline replacement decisions.

[15] id.

[16] 2024 Gas Safety Plan, p. 38, Table 7

[17] PG&E-03, Ch.4, p.2-14, line 13

[18] History of Aldyl A Piping System, Dr. Gene Palermo, American Gas Association: https://data.ntsb.gov/Docket/Document/docBLOB?ID=16626212&FileExtension=pdf&FileName=Palermo%20-%20History%20of%20Aldyl%20A%20Piping%20System-Rel.pdf, p. 22 of 24. **Note:** Dr. Gene Palermo, is a leading pipeline safety expert and long-time authority on polyethylene gas piping, who was a co-author on the CPUC's 2014 Hazard Analysis and Mitigation Report.

[19] CPUC Hazard Analysis & Mitigation Report, Tables 5, p.19

stress, longer-life conditions. [20][21] Treating all pre-1985 plastic as uniformly high risk is clearly inconsistent with the Commission's own pressure-sensitive risk evidence. A blanket 100-year replacement goal therefore materially understates actual asset life for large portions of the system.

TURN also notes that 'Aldyl A' is used in PG&E testimony as a shorthand for all pre-1985 plastic pipe, but the public Jana DIMP model documentation shows this is inaccurate. Aldyl 5040 is a specific early resin produced from 1965–1971, with print-line codes introduced in 1966 (A = 1966, B = 1967, etc.). The highest leak risk on PG&E's system is concentrated in this early-vintage Aldyl 5040—particularly pipe installed in the late 1960s and around 1970. In the Jana analysis of PG&E data (2013), Aldyl 5040 mains exhibit about 0.50 cumulative leaks per mile, far exceeding later materials such as LDIW (0.29), 5043 (0.15), and newer polyethylene resins, demonstrating that risk is confined to a narrow subset rather than all pre-1985 plastic.[22]

As mentioned previously, there is additional heterogeneity in pipe material risk, as shown in Table 1 of the CPUC's 2014 Hazard Analysis and Mitigation report, which shows that a significant change in manufacturing properties of Aldyl-A occured in the early 1970s:

[20] As mentioned later in this testimony, PG&E's high pressure (HP) cutoff for mains appears arbitrarily low i.e. 25 psig as opposed to 50+psig as indicated in the CPUC Hazard Analysis & Mitigation Report.
[21] CPUC Hazard Analysis & Mitigation Report, Tables 6, p.20
[22] JANA Dimp Model (public) GRC-2023-PhI_DR_TURN_081-Q08Atch03, Tables 6 and C1-2, p.13 and p.42 respectively.

Table 2: Different Vintages and Resins of Aldyl-A. Reproduced from: CPUC Hazard Analysis & Mitigation Report, Table 1,p.8 [23]

Approximate Years of Manufacture	Alathon Resin	Relative Resistance to Slow Crack Growth
1965-1970	5040	Low
1970-1972	5043, LDIW	Low
1970-1983	5043, non-LDIW	Medium
1983-1988	5046-C	Medium High
1988-1992	5046-U	High
1992-1999	5046-O	Very High

In Note 2 to Table 2 in CPUC's 2014 Hazard Analysis and Mitigation report, the CPUC explains that the "pre-1985" cutoff represents an arbitrary choice made to account for the potential lag between procurement and installation of pipeline.

Despite this clear heterogeneity, PG&E assumes all pre-1985 plastic and all pre-1941 steel as if risk were uniform. The disconnect is most explicit for MAT 50A, which PG&E describes as a workload-driven forecast—identified jobs plus forecast new jobs, then "divided by four to get the units needed per year" to fit the rate-case cycle (Ex. PG&E-3, p. 4-40, lines 13–20)—rather than a risk-driven mitigation program.

E. The Commission Should Not Be Swayed by Cherry-Picked Allegations of "Explosions"

As is typical, the utility implies that if the Commission does not authorize the pipeline replacement programs as proposed by PG&E, it will result in explosions and fatalities. The Commission must look through PG&E's histrionics.

First, PG&E notes that it has "incurred seven incidents resulting in an ignition or explosion associated with pre-1985 Aldyl-A pipe leakage since 1982." (PG&E-03, p. 4-33, lines 1-3.) However, as documented in the last rate case, there is no information available concerning the pipe installation year for two of the incidents, and only one of the other five incidents occurred

[23] PHMSA's Pipeline Safety Data Report Index organizes gas distribution safety metrics around **material type and vintage**, consistently using **pre-1970 and pre-1960 installation cutoffs** and highlighting **cast iron, wrought iron, and bare/unprotected steel** in its core inventories and performance measures, implicitly identifying these legacy materials and vintages as the federally recognized higher-risk categories for safety analysis and oversight.

on Aldyl-A pipe installed after 1975. The other four all occurred on plastic pipe installed in 1972-1974, as shown below:

Table 3: Four of the Five Incidents with Aldyl-A Pipe Occurred on Pipe Installed Before 1975[24]

Incident Date	Location	PHMSA ID #	Pipe Install Date
8/12/88	Clovis, CA	19890007	**1972**
10/26/04	Woodland, CA	20050005	1977
9/27/11	Roseville, CA	N/A[25]	**1973**
8/31/11	Cupertino, CA	20110369	**1973**
1/12/17	Yuba City, CA	20170016	**1974**

Because the "seven incidents" on its system do not necessarily support its strategy to replace all pre-1985 plastic pipe, PG&E discusses at length two tragic pipe explosions that occurred in 2023 and 2024 in Utah and Pennsylvania, resulting in eight fatalities. One occurred due to failure of an Aldyl A main manufactured in 1976, and the other occurred due to failure of a 1982 Aldyl A service tee. (PG&E-03, p. 4-31 to 4-32)

The PHMSA database shows 469 gas distribution pipeline incidents in 2006-2025, with 171 fatalities.[26] In 2023 and 2024 there were 36 incidents resulting in 26 fatalities. I have not conducted a comprehensive analysis of PHMSA incident data to establish whether PG&E has selectively picked two incidents to support its position concerning Aldyl A pipelines.

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[24] Incident data from PHMSA incident database, available at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data. If needed,
[25] Information concerning the 2011 Roseville incident based on Mercury News article of 10/13/2011.
[26] See, https://portalpublic.phmsa.dot.gov/analytics/saw.dll?PortalPages

IV. RISKFINDER / DIMP MODEL: THE COMMISSION'S PRIMARY QUANTITATIVE RISK TOOL, BUT NOT USED TO DETERMINE PG&E PIPELINE REPLACEMENT PACE (2027-2030)

PG&E's DIMP program relies on the RiskFinder model, a quantitative risk assessment tool that calculates Risk of Failure (RoF) for individual pipeline segments.[27] The model operates through a straightforward formula: RoF = Likelihood of Failure (LoF) × Consequence of Failure (CoF).[28]

RiskFinder implements PHMSA's eight DIMP threat categories (corrosion; equipment failure; excavation damage; incorrect operations; material/weld/joint failure; natural forces; other outside forces; other), subdivides them into "sub-threats," and calculates risk at the feature level (mains, services, AGFs, regulator stations).[29] The core structure is: RoF_sub-threat = LoF × CoF**,** and RoF_total = Σ RoF_sub-threats across applicable sub-threats. LoF is built from baseline leak rates (district/plat) plus supplemental factors (e.g., leak history, installation year, material, hazards) scaled by feature length/count; CoF multiplies severity, migration, pressure, population density, and excess flow valve (EFV) factors. The model is data-driven and operationally rigorous. However, it contains a fundamental structural flaw that undermines its use as justification for pipeline replacement programs: approximately 75 percent of identified risk stems from threats unrelated to pipeline material condition or age, and therefore unaddressable through replacement alone.

A. The Risk Model Undermines The Replacement Case: Operational Threats Exceed Material Threats By 7-To-1

Even before getting into weighting choices, factor selection, and data quality, the threat taxonomy itself shows why a "risk-based" score does not automatically justify pipeline replacement as the mitigation.

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[27] PG&E Response to TURN_062_Q001, subpart c: "In the context of Exhibit (PG&E-03), Chapter 4, the DIMP operational model is synonymous with the RiskFinder model."

[28] PG&E Response to TURN_062_Q001, Attachment H (Threat Identification and Risk Evaluation)

[29] PG&E Response to TURN_062_Q001, Attachment N (Risk Algorithm)

RiskFinder categorizes threats into eight categories: Incorrect Operations, Excavation Damage, Other, Natural Forces, Corrosion, Material Weld or Joint Failure, Outside Forces, and Equipment Failure. The model's risk rankings show the problem starkly:

Table 4: PG&E Response to TURN_062_Q001, Attachment H (Threat Identification and Risk Evaluation)[30]

Rank	Threat	Risk	Percent
1	Incorrect Operations	86,937	34%
2	Excavation	73,715	29%
3	Other	29,926	12%
4	Natural Forces	24,466	10%
5	Corrosion	16,174	6%
6	Material	13,890	5%
7	Outside Forces	6,173	2%
8	Equipment	4,076	2%
	Total	**255,358**	**100%**

Only three threat categories—Material, Weld or Joint Failure (5%), Corrosion (6%), and Equipment Failure (2%)—relate directly to pipeline physical condition and could theoretically justify replacement. These account for 13 percent of identified risk. 75 percent of the risk to pipelines stems from threats that replacement may not address: incorrect operations (34%), excavation damage (29%), and other unspecified failures (12%).[31]

The largest single risk driver at 34 percent of total risk encompasses failures from "inadequate procedures or safety practices, or failure to follow correct procedures, or other operator error." No amount of pipeline replacement may resolve this threat, unless the new replacement fixes

[30] Based on the 2024 PHMSA national gas distribution *Leaks by Cause* dataset—used by TURN as a proxy for risk-by-cause—U.S.-wide distribution leaks are primarily driven by **equipment (40.5%)** and **corrosion (17.1%)**, together accounting for ~58% of leaks. By contrast, PG&E's distribution risk profile is dominated by **incorrect operations and excavation damage (~63%)**, indicating that PG&E's system risk is less driven by traditional asset-condition justifications for accelerated replacement (e.g., corrosion or material failure) than the federal distribution baseline. Source: https://portalpublic.phmsa.dot.gov/analytics/saw.dll?PortalPages&PortalPath=/shared/PDM%20Public%20Website/_portal/GD%20IM%20Perf

[31] TURN notes that roughly 12% of residual risk—attributable to natural forces (10%) and other outside forces (2%)—can act as a threat multiplier on pre-1985 pipe, increasing LoF despite being largely independent of material condition.

problems caused by incorrect operations during historical installation. Instead, it may require organizational or behavioral change: improved training, revised standard operating procedures, enhanced supervision, and better oversight. Similarly, Excavation Damage (29% of risk) results from “Failure or previous damage due to excavation activity” such as third-party digging, marking failures, or unsafe excavation practices—all addressable through better locate and mark procedures, contractor safety trainings, and better adherence to dig-in protocols, not pipeline replacement.[32] [33]

Similarly, Outside Forces (2% of risk) includes vandalism, third-party damage, rodent damage, and vehicle impact. These operational and environmental hazards are largely independent of pipeline age or material type.

The implication is straightforward: PG&E's RiskFinder or DIMP model demonstrates that the highest ranked risk-threat categories are largely independent of pipeline age or material condition, but operational and exogenous threats that no amount of pipeline replacement may address..

B. Likelihood of Failure: Weighting Choices Systematically Favor Pre-1985 Plastic and Early-Vintage Steel

RiskFinder’s Likelihood of Failure (LoF) is presented as a data-driven construct, but Attachment N Appendix B shows that weighting choices materially drive results—and do so in a way that is arbitrary and appears to systematically elevate LoF for pre-1985 plastic (especially Aldyl A) and early-vintage steel. First, where a supplemental factor is found to be “statistically significant,” PG&E frequently assigns it 70% of total LoF weight**,** with the remaining 30% allocated to district baselines to “account for geographic effects” (e.g., excavation damage; construction defects; plastic material failure). This split is asserted, not derived: Appendix B does not show

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[32] PG&E Response to TURN_062_Q001, Attachment H (Threat Identification and Risk Evaluaiton), Table 1

[33] Over the 2015–2024 period, PHMSA data show that excavation-related gas distribution damages are overwhelmingly attributable to preventable root causes—approximately 40% to insufficient excavation practices, 33% to inadequate one-call notification, and 23% to deficient locating practices—with only ~5% falling into other categories—indicating that the vast majority of excavation damages are addressable through improved operational, contractor, and damage-prevention practices. Source: https://portalpublic.phmsa.dot.gov/analytics/saw.dll?PortalPages&PortalPath=/shared/PDM%20Public%20Website/_portal/GD%20IM%20Perf

model selection criteria, goodness-of-fit comparisons across alternative weightings, or sensitivity testing demonstrating that 70/30 is optimal rather than arbitrary. The result is a structural amplification of factors that disproportionately penalize older assets—installation year, past leaks, or Jana Aldyl-A rankings—regardless of current operating conditions or geography-specific variance in likelihood of pipe failures.

Second, in corrosion modeling, PG&E repeatedly zeros out plat-level baselines on the assumption that LoF "does not correlate at the plat level," while simultaneously assigning equal weights (0.333 each) to segment leak history, leak rates, and installation year for external corrosion on services. These equal weights are justified only by "strong confidence," not by comparative explanatory power. Moreover, as shown in the figure showing the ~2000 miles of highest risk segments identified by PG&E's own modeling, plastic and steel pipeline is highly heterogeneously spread across its 18 divisions. About 75% of the high risk plastic main mileage is in the East Bay, San Francisco and San Jose divisions.

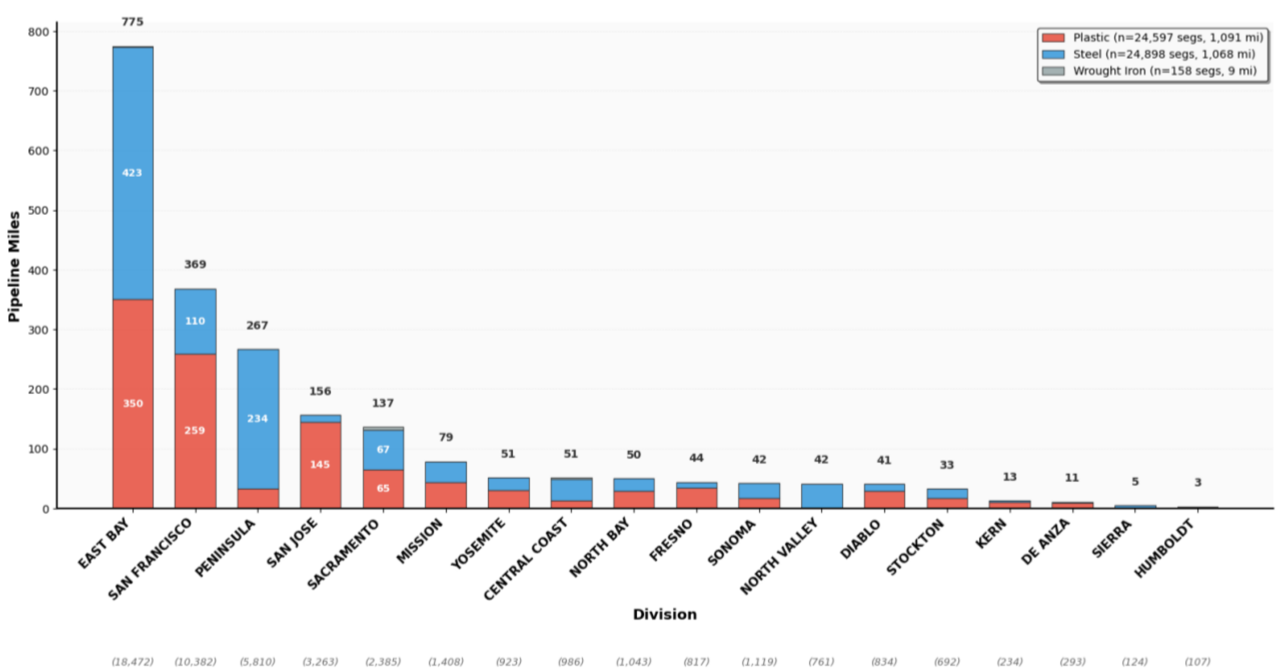

Figure 2: PG&E Pipeline Material by Division and Material Type (Total: 2,168 miles, 49,653 segments)

Furthermore, no evidence is provided that installation year explains future leaks as strongly as observed or actual leak history—yet it is weighted identically. Third, for Aldyl A plastic mains, PG&E bypasses baseline factors and uses dated Jana calculator outputs, while non-Aldyl plastics retain a 30% district baseline. This asymmetry ensures that Aldyl A segments cannot benefit from favorable district or plat performance, locking in elevated LoF regardless of observed outcomes. Similar asymmetries appear for older steel, where installation-year is given higher weight and geographic location is ignored.

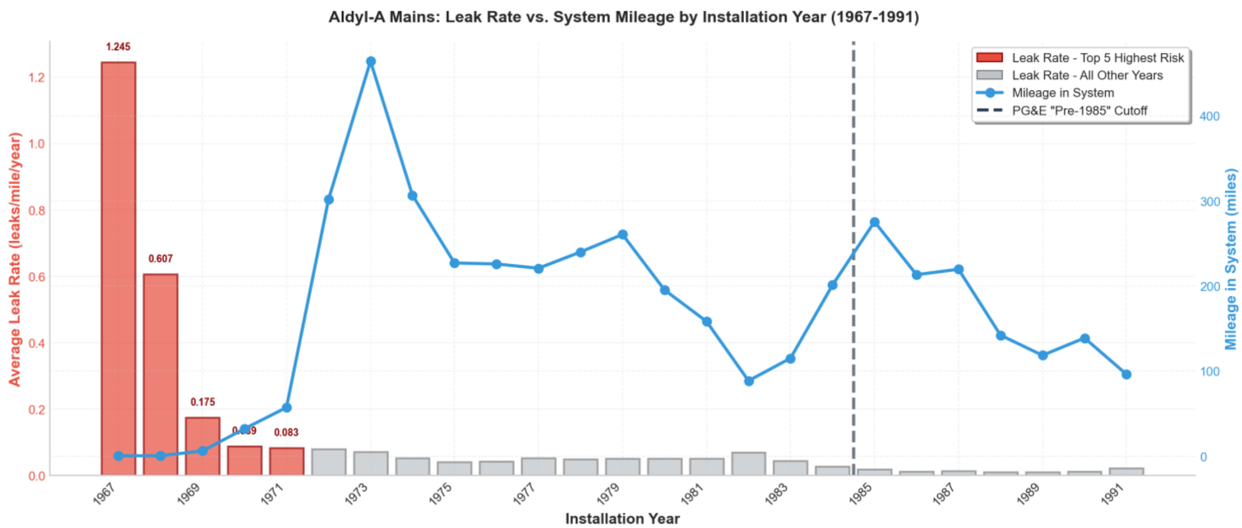

Figure 3: PG&E's uniform pre-1985 replacement of 139 miles per year targets an entire 40-year vintage cohort, yet 93% of documented risk is concentrated in just five installation years (1967–1971) representing barely 2% of the pre-1985 system.

Taken together, these weighting conventions are not neutral reflections of risk. They appear to systematically magnify pre-1985 age- and material-based penalties while minimizing countervailing evidence from geography, operating pressure, or heterogeneity in contractor safety across PG&E's 18 divisions. Because LoF directly multiplies with CoF in the RoF calculation, these choices bias RiskFinder outputs toward replacement of pre-1985 plastic and early-vintage steel.

Because mileage is unevenly distributed across vintages, TURN provides an illustrative example to evaluate leak performance using a mileage-weighted system average leak rate across all Aldyl-A mains. Using sub-decade cohorts, the weighted average leak rate is approximately 0.053

leaks per mile-year (213.16 weighted leaks over 4,045.5 miles). Against this benchmark, the 1967–1971 Aldyl-A cohort exhibits a leak rate roughly eight times the system average, targeting just 2% of Aldyl-A mains, while all post-1976 cohorts are at or below average system leak rate (See TURN Recommendation 3).

Table 5: Sub-decade plastic pipeline cohorts and average leak rates[34]

Installation period	Mileage	Avg leak rate / mile	Relative leak rate vs. system avg
1967–1971	96.3	0.42008	**≈ 8.0× higher**
1972–1976	1,445.8	0.05715	**≈ 1.1×**
1977–1981	1,074.8	0.05050	**≈ 1.0×**
1982–1986	813.1	0.03286	**≈ 0.6×**
1987–1991	615.5	0.01476	**≈ 0.3×**

C. Consequence Of Failure: Material-Related Threats Carry the Lowest Consequences

PG&E's own Consequence of Failure data reveals that material-driven threats—the primary categories theoretically addressed by pipeline replacement—carry the lowest severity consequences. Based on nationwide PHMSA data (2003-2022), Material/Weld/Joint Failure generates 5.8 SIFs per 100,000 leaks, Corrosion 0.9, and Equipment 0.1.[35] By contrast, the operational and exogenous threats PG&E may not mitigate through pipeline replacement generate far higher consequences (reported as SIFs per 100,000 leaks): Other Outside Forces (84.3), Incorrect Operations (57.3), Natural Forces (19.5), and Excavation Damage (15.1). Material-specific consequences are an order of magnitude lower than operational consequences.

Similar to its broad pipeline vintage based cutoffs, PG&E's pressure factor also appears to distinguish only between >25 psig (high pressure) and ≤12 (low pressure), producing a narrow consequence spread that does not meaningfully differentiate lower-stress operating conditions

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[34] CombinedResults_Main_3545jobs.xlsx; GRC-2027-PhI_DR_TURN_062-Q004Supp01

[35] PG&E Response to TURN_062_Q001, Attachment N Appendix C, Table 1. SIF = significant injuries or fatalities.

(30-40 psig), documented by the Commission as substantially increasing the Mean Time To Failure (MTTF) (i.e. reducing RoF).[36]

PG&E's own CoF data shows pipeline replacement targets threats with comparatively low consequences, while the dominant drivers of severe outcomes—operational failures and external hazards—remain unaffected by replacement. Consequence analysis, therefore, also does not justify the proposed capital spending.

D. PG&E Does Not Actually Utilize Risk Model Results in Its GRC Replacement Forecast

Most importantly, PG&E has invested substantial resources developing the RiskFinder/DIMP model, documented in hundreds of pages of technical guidance, data specifications, and risk algorithm explanations.[37] Despite the flaws highlighted above, it is the best available analytical tool to identify and target risk of failure across PG&E's distribution pipeline system. Yet when asked whether the 2027 GRC pipeline replacement forecast is informed by DIMP outputs, PG&E provides a striking answer: "No, these outputs did not directly inform the forecasts for MATs 14A, 14D, and 50A." (GRC-2027-PhI_DR_TURN_062-Q004, Answer b) More starkly, PG&E confirms that "none of the 3,545 jobs identified for mitigation analysis are included in the 2027 GRC forecast." (GRC-2027-PhI_DR_TURN_062-Q004, Answer c.i)

Instead, PG&E's 2027 forecast is based on administrative fiat: "continuing the pace for which the Commission adopted a forecast in the 2023 GRC, i.e., 25 miles per year of pre-1941 steel to be replaced through PG&E's GPRP (MAT 14A) and 139 miles per year of pre-1985 Aldyl-A and similar plastic materials (MAT 14D)," as well as an increased pace for MAT 50A—presumably to align with an asset-management objective of replacing pre-1985 plastic by 2030.[38][39]

This is a continuation of historical replacement pace, not a risk-informed allocation. The DIMP model—with its threat categorization, likelihood and consequence calculations, and mitigation analysis—serves no function in determining PG&E's 2027 GRC forecast. The elaborate risk

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36 PG&E Response to TURN_062_Q001, Attachment N Appendix C, Table 4
37 See Footnote 13 above.
38 PG&E-3, pp. 4-26–4-27; 2024 Gas Safety Plan, p. 38, Table 7
39 PG&E-3, p. 4-26, lines 7–11

framework PG&E developed has been sidelined in favor of hitting a numerical target: replace all pre-1985 Aldyl-A by 2030, and pre-1941 steel on a predetermined schedule. PG&E is seeking a blank check for predetermined vintage categories, using DIMP as window-dressing to sequence segments within the pre-authorized mileage envelope.

In fact, the utility acknowledges this is not evidence-based allocation when it notes: "Though the modeling performed in connection with the RAMP proceeding has assigned these programs relatively low CBRs, the pipe to be replaced has substantial risk, as identified by the industry as a whole, by experts at the CPUC, and by PG&E's own experts."[40] In other words: the model says the programs do not provide cost-effective risk reduction, but we are proceeding anyway because our internal consensus and Commission experts warrant it.[41]

V. TURN RECOMMENDATIONS CONCERNING REPLACEMENT MILEAGE AND UNIT COSTS

Given the limitations discussed above, TURN relies on PG&E's own model outputs to propose a more targeted, evidence-based replacement approach. PG&E's RiskFinder results show that average risk of failure is highest for steel and exceeds that of all plastic categories—including Aldyl A—while plastic risk varies widely and is often driven by non-material threats such as incorrect operations rather than intrinsic pipe condition. TURN therefore examines PG&E's own RiskFinder outputs to propose a more granular, evidence-based alternative that respects both the technical foundation PG&E built and the urgent need for rational prioritization.

Separately, TURN recommends a more reasonable unit cost forecast based on PG&E's recorded historical weighted average replacement costs, as well as a comparison to replacement costs for Southern California Gas Company.

Lastly, TURN recommends the Commission direct PG&E to actually use its DIMP model to develop a risk-based pipeline replacement plan in its next GRC.

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[40] PG&E-3, p. 4-26, lines 15–19
[41] Here, PG&E appears to reference the 2014 CPUC Hazard Analysis & Mitigation Report, which in no way suggests wholesale mains replacement as proposed by PG&E.

A. Recommendation 1: Adopt a Risk-Aligned Replacement Pace Consistent With PG&E's Own Data

TURN Recommendation 1 builds directly on PG&E's own RiskFinder outputs and the per-mile risk intensities shown in the CombinedResults_Main_3545jobs.xlsx.[42] Those results show that steel mains are consistently riskier than plastic on a per-mile basis, which supports the Commission's long-standing acceptance of a steel replacement pace of roughly 25 miles per year as risk-aligned. Another important factor to note is that, among the riskiest ~2,000 miles across PG&E territory, steel and plastic are almost 50/50 distributed as shown below, which allows for an apples-to-apples (normalized) risk comparison:

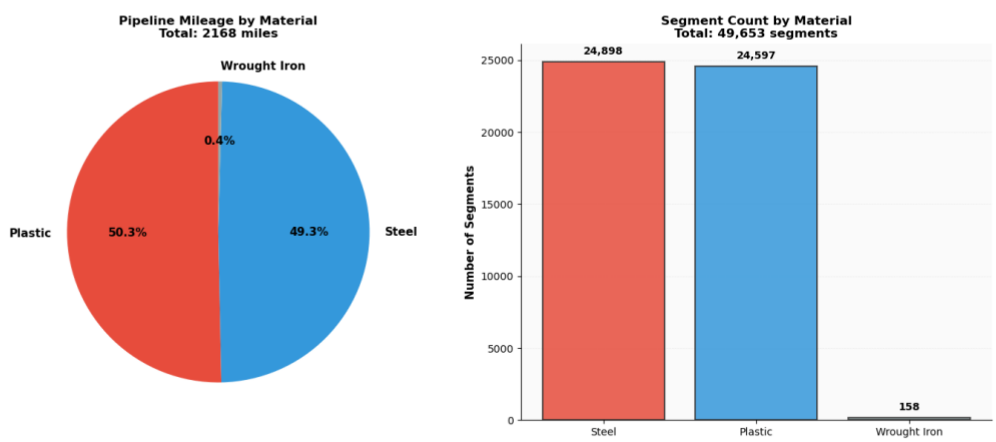

Figure 4: DIMP 3,545 jobs overview (n= 2,168 total miles)

Across PG&E's territory, the RiskFinder results show a clear and consistent risk hierarchy by material: wrought iron exhibits the highest risk of failure per mile, followed by steel, with plastic lowest. The heatmap below underscores that steel mains are systematically higher risk than plastic across all divisions.

[42] CombinedResults_Main_3545jobs.xlsx; GRC-2027-PhI_DR_TURN_062-Q004Supp01

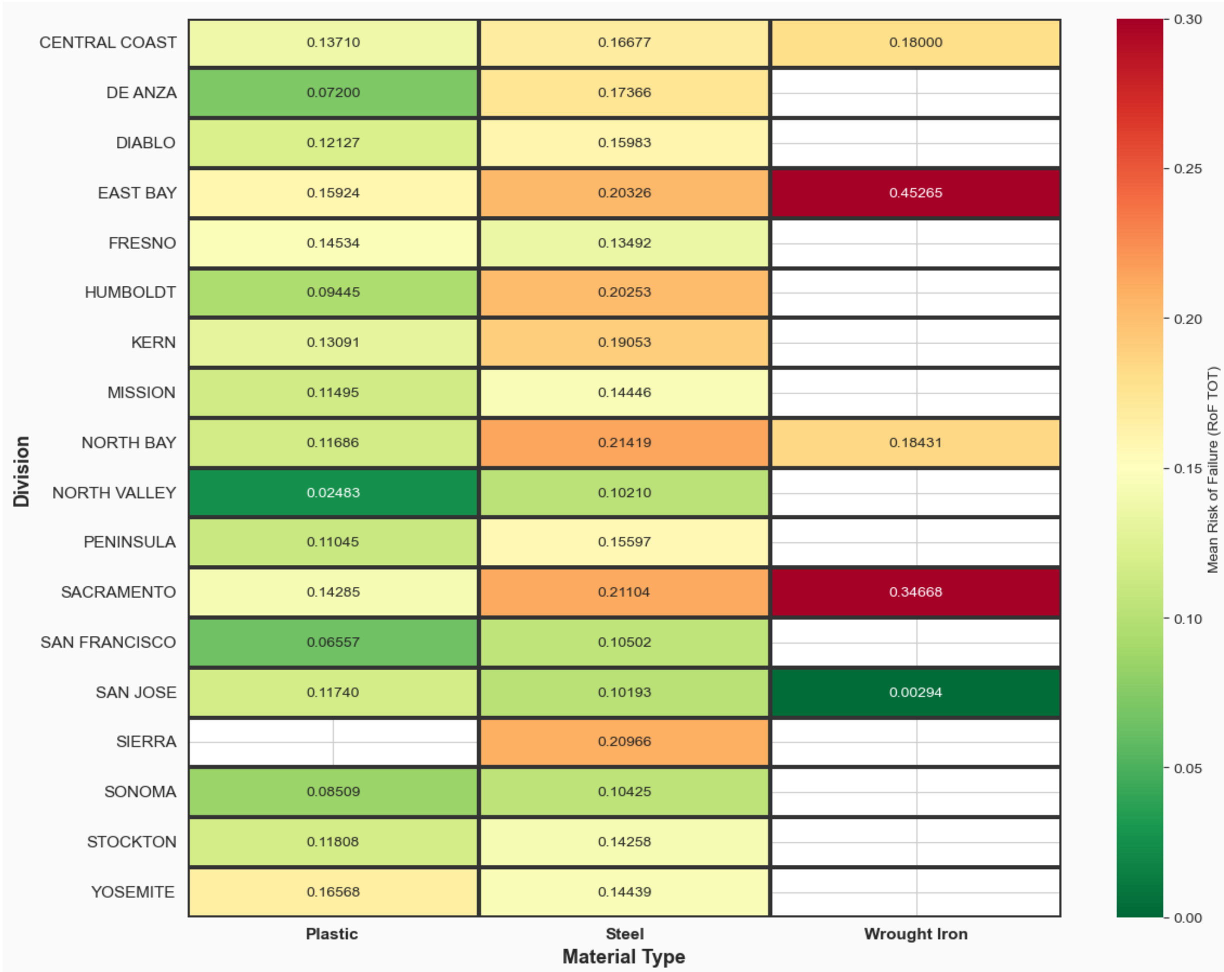

Figure 5:Mean Risk of Failure (RoF TOT) by Division and Material Type (Red = Higher Risk, Green = Lower Risk)

PG&E's own DIMP-derived RiskFinder data thus reveal a consistent material-type risk hierarchy across all 18 service divisions: wrought iron demands urgent replacement in East Bay and Sacramento divisions where it exceeds 0.3 RoF/mile (the highest risk threshold on the scale); steel mains present elevated and sustained risk across nearly all territories, with pre-1941 steel systematically exceeding 0.2 RoF/mile in East Bay, Humboldt, North Bay, Sacramento, and Sierra Divisions; and plastic mains, by contrast, remain below ~0.15 RoF/mile system-wide, except Yosemite (0.16). Taken together, these figures demonstrate that steel replacement is already aligned with higher per-mile risk, whereas plastic remains materially less risky on average, reinforcing the case for calibrating plastic replacement pace to the higher risk steel baseline, rather than pursuing an undifferentiated, mileage-driven program as recommended by PG&E.

In particular, pre-1941 steel exhibits about 1.24× higher RoF per mile than post-1941 steel, indicating that PG&E's pre-1941 steel mileage exhibits the highest risk/mile across its own pipeline vintage cutoffs.

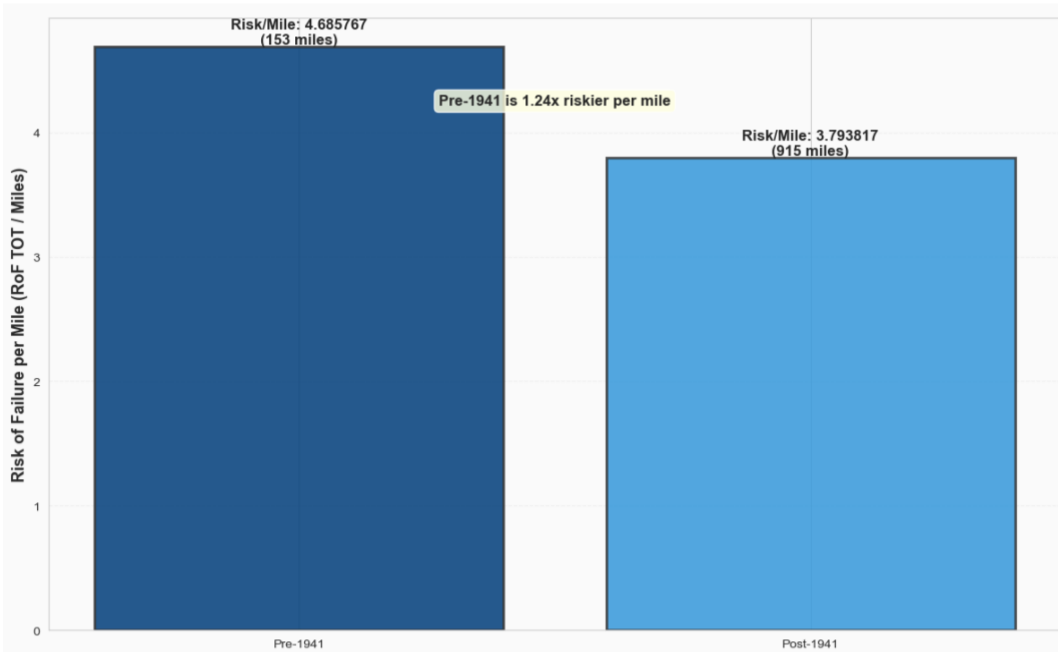

Figure 6: STEEL: Risk Intensity by Installation Cohort (Pre-1941 vs. Post-1941)

By contrast, the same PG&E data show that pre-1985 plastic is materially less risky than pre-or-post-1941 steel on a per-mile basis. Compared to pre-1941 steel (RoF:4.68/mile), pre-1985 plastic (RoF:2.87/mile) is about is roughly 1.6× lower risk. Even compared to post-1941 steel (RoF:3.79), pre-1985 plastic is about 1.3x lower risk.

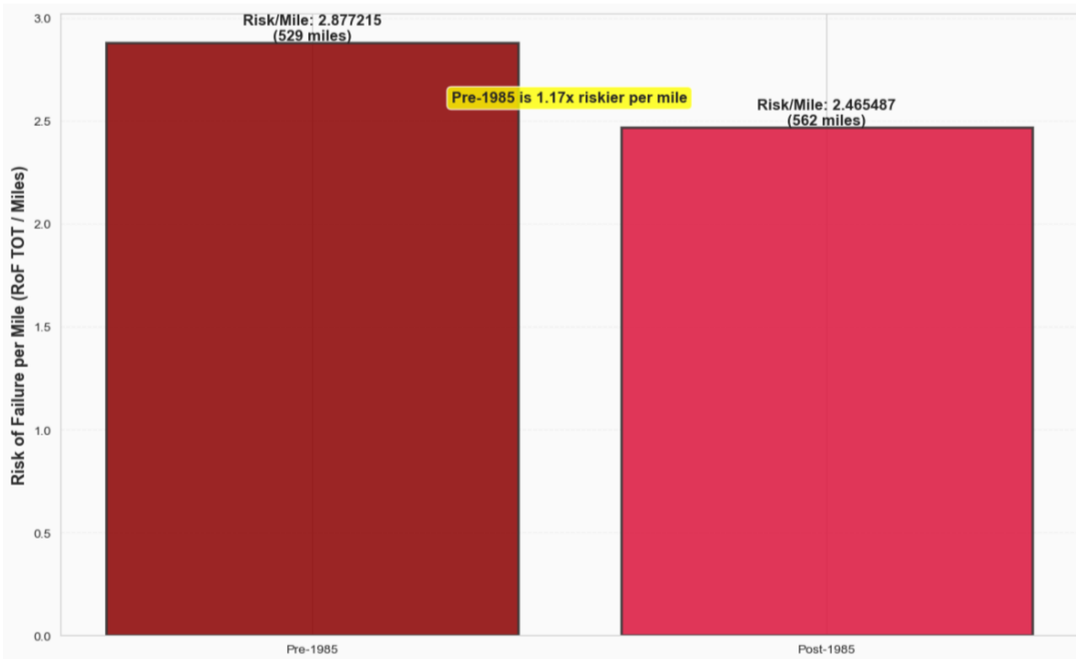

Figure 7: PLASTIC: Risk Intensity by Installation Cohort (Pre-1985 vs. Post-1985)

Accordingly, if 25 miles per year of steel replacement reflects appropriate risk-proportional diligence under 49 CFR Part 192, Subpart P, then plastic replacement should be calibrated to this highest per-mile risk benchmark. Anchoring replacement volumes to demonstrated per-mile risk, rather than arbitrary mileage targets, prevents overstating the need for large-scale plastic replacement and ensures plastic pipelines receive no greater replacement pace than higher-risk steel, which therefore sets the appropriate upper bound.

TURN therefore recommends the following replacement mileage:

- **MAT 14A (pre-1941 steel): 25 miles per year**
- **MAT 14D (pre-1985 plastic): 85 miles per year,** consistent with the replacement percentage for the highest risk steel pipeline.This is illustrated in the table below:

Table 6: TURN Recommended Mileage for MAT 14D

Install Year	Miles	PG&E Proposed Miles	PG&E Proposed Miles (%)	TURN Recommended Miles	% Diff (TURN vs. PG&E)
pre-1941 steel	1920	25	1.3%	25	0%
pre-1985 plastic	6546	139	2.1%	85[43]	-38%

- **MAT 50A (reliability mains): 15 miles per year**, consistent with the 2023 GRC authorization

Table 7: TURN Recommendation 1

		Value	Source				
	Weighted average per mile mains replacement cost	$3,871,135.03	PG&E R.24-09-012)				
	2027-2030 Forecast Summary						
	Description	2027	2028	2029	2030	Total	Note
1	Forecast Unit Cost (per mile) MAT 14A	$5,715,626.34	$5,747,620.98	$5,791,785.39	$5,857,364.39		02. Exh 3_Ch4_ConsolidatedWPs_CLEAN, WP 4-27 14A_D_50A
2	Forecast Unit Cost (per mile) MAT 14D	$4,132,492.92	$4,155,625.58	$4,187,557.18	$4,234,971.89		
3	Forecast Unit Cost (per mile) MAT 50A	$5,580,158.43	$5,611,394.76	$5,654,512.41	$5,718,537.11		
11	TURN proposed replacement mileage MAT 14A	25	25	25	25		TURN Recommendation 1
12	TURN proposed replacement mileage MAT 14AD	85	85	85	85		
13	TURN proposed replacement mileage MAT 50A	15	15	15	15		
14	TURN Proposed Final Replacement Capital MAT 14A	$142,890,658.44	$143,690,524.45	$144,794,634.74	$146,434,109.74	$577,809,927.37	TURN Recommended Capital based on Recommendation 1
15	TURN Proposed Final Replacement Capital MAT 14AD	$351,261,898.11	$353,228,173.99	$355,942,360.34	$359,972,610.52	$1,420,405,042.95	
16	TURN Proposed Final Replacement Capital MAT 50A	$83,702,376.49	$84,170,921.36	$84,817,686.21	$85,778,056.58	$338,469,040.64	
17	Total	$577,854,933.03	$581,089,619.80	$585,554,681.28	$592,184,776.84	$2,336,684,010.96	

B. Recommendation 2: Adopt Lower Unit Costs In Line with Historical Data

PG&E's 2027–2030 unit cost forecasts for pipeline replacement programs appear substantially elevated relative to both PG&E's own recent historical distribution pipeline costs provided in R.24-09-012 and compared to other California gas utilities.

PG&E's GRC forecast unit costs are: MAT 14A (Steel): $5.72–$5.86 million per mile; MAT 14D (Plastic): $4.13–$4.23 million per mile; MAT 50A (Reliability Main): $5.58–$5.72 million per mile.[44]

[43] 1.3% of pre-1985 plastic mileage, i.e. same percent of mileage as used for highest risk steel.
[44] PG&E-3, Ch. 4, Workpaper Table 4-26

However, PG&E's own 2021–2024 recorded cost data show a weighted average of $3.87 million per mile across all divisions and service areas.[45] PG&E's San Francisco and East Bay divisions, the highest-cost areas in PG&E's portfolio, show recorded costs of $7.43 million and $5.28 million per mile respectively—consistent with high urban density and congestion. However, these represent outliers, not system average. The Peninsula and North Bay divisions, representing substantial volumes, show costs of $4.93 million and $3.62 million per mile respectively.

Specifically, PG&E's GRC forecast for MAT 14D (plastic replacement) averages $4.18 million per mile over 2027–2030, approximately 8 percent higher than recorded 2021-2024 unit costs. For MAT 14A (steel), the forecast averages $5.79 million per mile against a weighted historical average of $3.87 million per mile—a 50 percent premium. For MAT 50A, the forecast of $5.58–$5.72 million per mile is 45% higher than the weighted historical average.

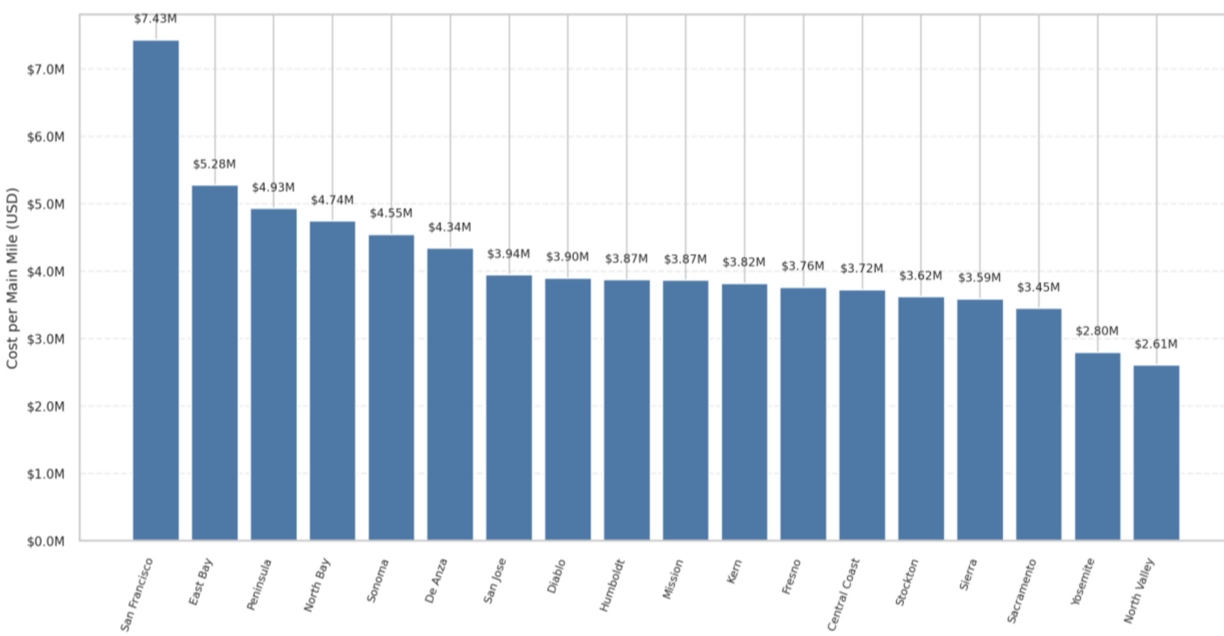

Figure 8: PG&E cost per main mile replaced

[45] R.24-09-012, Spreadsheet of Distribution Replacement Costs Data, cell B9, submitted by PG&E on Nov. 5, 2025 in "Response to Administrative Law Judges' Ruling Directing Gas Utilities to Provide Gas Distribution Cost Data."

PG&E acknowledges this discrepancy exists "due to volumes of work differing by PG&E operating districts (divisions)" and cautions that "any ratesetting activity should rely on the forecast presented in the General Rate Case" rather than historical actuals.[46] This caveat is problematic: if historical costs are materially lower than PG&E's proposed unit costs for the 2027 GRC application, and lower than comparable gas utility per mile unit costs for pipeline replacement, PG&E's own 2021-2024 historical average cost data should be used with appropriate escalators.

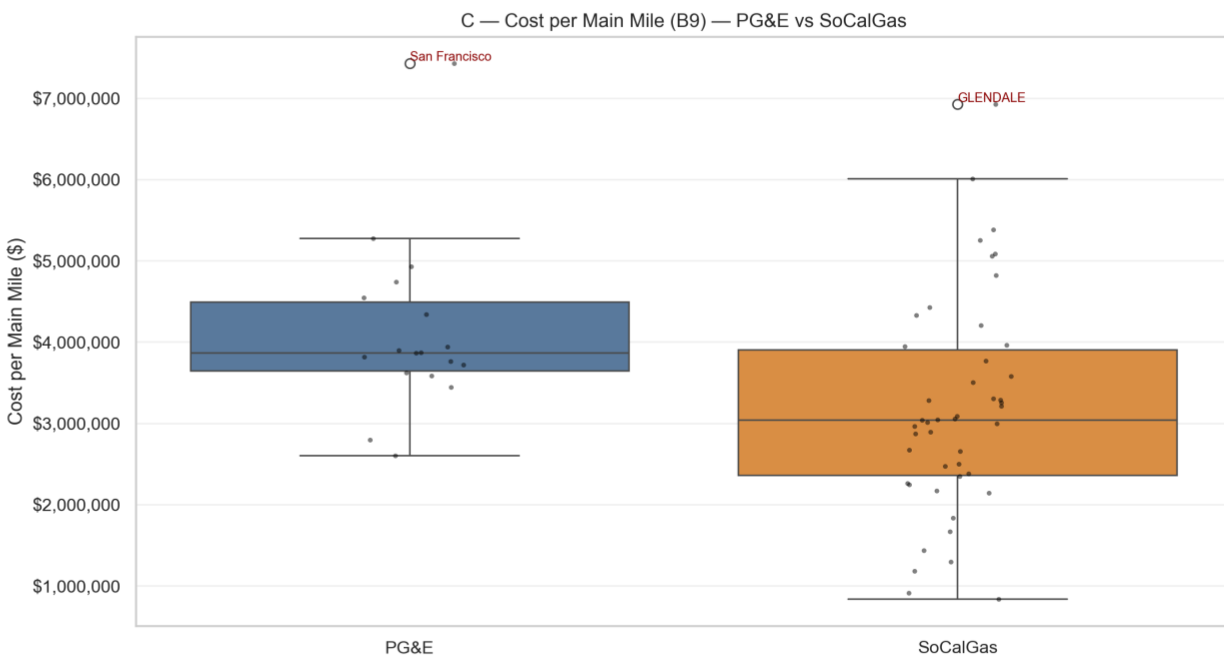

Figure 9: PG&E vs. SoCalGas – box-and-whisker plots (with IQR) for cost per main mile

The distribution cost data submitted in R.24-09-012 also illustrate a significant cost differential between PG&E and SoCalGas.

SoCalGas replacement costs show a median of approximately $3.1 million per mile, with an interquartile range of $2.3–$3.9 million, substantially below PG&E's forecast. (**Error! Reference source not found.**). PG&E's GRC forecast unit costs substantially exceed PG&E's own 2021–2024 recorded weighted average of $3.87 million per mile.

[46] id.

TURN proposes adopting PG&E's 2021–2024 historical weighted average ($3.87 million per mile) as the baseline, escalated by TURN's proposed escalation factors using material-type baseline for MAT14D (factor = 1.0) with MAT 14A (Steel) and MAT 50A (Reliability) escalated according to forecast cost relationships in PG&E's GRC forecast:

Table 8: Recommendation 2: Unit cost correction

Program (MAT)	PG&E $/mile 2027	TURN $/mile 2027	%Diff	PG&E $/mile 2028	TURN $/mile 2028	%Diff	PG&E $/mile 2029	TURN $/mile 2029	%Diff	PG&E $/mile 2030	TURN $/mile 2030	%Diff
MAT 14A (Steel)	$5,715,626.34	$5,354,143.80	**-6.3%**	$5,747,620.98	$5,354,143.80	**-6.8%**	$5,791,785.39	$5,354,143.80	**-7.6%**	$5,857,364.39	$5,354,143.80	**-8.6%**
MAT 14D (Plastic)	$4,132,492.92	$3,871,135.03	**-6.3%**	$4,155,625.58	$3,871,135.03	**-6.8%**	$4,187,557.18	$3,871,135.03	**-7.6%**	$4,234,971.89	$3,871,135.03	**-8.6%**
MAT 50A (Reliability)	$5,580,158.43	$5,227,243.51	**-6.3%**	$5,611,394.76	$5,227,243.51	**-6.8%**	$5,654,512.41	$5,227,243.51	**-7.6%**	$5,718,537.11	$5,227,243.51	**-8.6%**

TURN's Recommendation 1 (mileage adjustment) and Recommendation 2 (unit-cost correction) together result in 2027 capital forecast of $541 million, reducing PG&E's forecast of $885 million by about 39%.

Table 9: TURN Recommendation 1 & 2

		Value	Source				
	Weighted average per mile mains replacement cost	$3,871,135.03	PG&E R.24-09-012)				
	2027-2030 Forecast Summary						
	Description	**2027**	**2028**	**2029**	**2030**	***Total***	**Note**
1	Forecast Unit Cost (per mile) MAT 14A	$5,715,626.34	$5,747,620.98	$5,791,785.39	$5,857,364.39		02. Exh 3_Ch4_ConsolidatedWPs_CL
2	Forecast Unit Cost (per mile) MAT 14D	$4,132,492.92	$4,155,625.58	$4,187,557.18	$4,234,971.89		
3	Forecast Unit Cost (per mile) MAT 50A	$5,580,158.43	$5,611,394.76	$5,654,512.41	$5,718,537.11		
4	Capital Escalation from 2024 to Forecast Year	1.0000	1.0000	1.0000	1.0000		Remove PG&E's escalation
5	**Material Type Escalation Factor (Plastic Baseline = 1.0000)**	1.0000	1.0000	1.0000	1.0000		Include TURN's proposed escalation
6	MAT 14A (Unit of Measure: feet of main replaced)	1.3831	1.3831	1.3831	1.3831		Row 1 / Row 2
7	MAT 50A (Unit of Measure: feet of main replaced)	1.3503	1.3503	1.3503	1.3503		Row 3 / Row 2
	2027-2030 Forecast Summary (TURN)						
	Description	**2027**	**2028**	**2029**	**2030**		**Note**
8	Forecast Unit Cost (per mile) MAT 14A	$5,354,143.80	$5,354,143.80	$5,354,143.80	$5,354,143.80		**TURN Recommendation 2**
	% Diff (vs. PG&E)	-6.3%	-6.8%	-7.6%	-8.6%		
9	Forecast Unit Cost (per mile) MAT 14D	$3,871,135.03	$3,871,135.03	$3,871,135.03	$3,871,135.03		
	% Diff (vs. PG&E)	-6.3%	-6.8%	-7.6%	-8.6%		
10	Forecast Unit Cost (per mile) MAT 50A	$5,227,243.51	$5,227,243.51	$5,227,243.51	$5,227,243.51		
	% Diff (vs. PG&E)	-6.3%	-6.8%	-7.6%	-8.6%		
11	Proposed replacement mileage MAT 14A	25	25	25	25		**TURN Recommendation 1**
12	Proposed replacement mileage MAT 14AD	85	85	85	85		
13	Proposed replacement mileage MAT 50A	15	15	15	15		
14	TURN Proposed Final Replacement Capital MAT 14A	$133,853,594.93	$133,853,594.93	$133,853,594.93	$133,853,594.93	$535,414,379.72	**TURN Recommendations 1 & 2**
15	TURN Proposed Final Replacement Capital MAT 14AD	$329,046,477.48	$329,046,477.48	$329,046,477.48	$329,046,477.48	$1,316,185,909.93	
16	TURN Proposed Final Replacement Capital MAT 50A	$78,408,652.60	$78,408,652.60	$78,408,652.60	$78,408,652.60	$313,634,610.39	
17	Total	$541,308,725.01	$541,308,725.01	$541,308,725.01	$541,308,725.01	$2,165,234,900.04	

C. Recommendation 3: For Pg&E's 2031 GRC Application, The Commission Should Require DIMP-Informed Segment-Level Replacement Plan With Post-Implementation Risk Verification

PG&E's proposed pipeline replacement programs (MATs 14A, 14D, 50A) fail to use risk-based prioritization and its 2027 GRC forecast, rather than using DIMP outputs to guide segment selection, chooses a predetermined pace from the 2023 GRC. PG&E explicitly confirms that "none of the 3,545 jobs identified for mitigation analysis [by DIMP] are included in the 2027 GRC forecast."[47] The DIMP model is abandoned in favor of meeting an administrative target: retire all pre-1985 plastic by 2030.

TURN recommends that, for PG&E's 2031 GRC, the Commission should require: (1) Segment-level DIMP-based prioritization, including sub-decade age cohorts, to replace blunt vintage cutoffs and transparently rank replacement candidates by Risk of Failure; (2) division- and census-tract-level risk disaggregation to demonstrate that replacement capital is targeted to the highest-risk populations and geographies; and (3) post-implementation risk verification,

[47] GRC-2027-PhI_DR_TURN_062-Q004, Answer c.i

including DIMP re-runs and model calibration, to confirm that realized risk reduction aligns with projections and to benchmark risk reduction per dollar against alternatives.

1.a. Segment-Level DIMP Prioritization and sub-decade age cohorts for MAT14D

TURN recommends PG&E provide a comprehensive analysis ranking all in-scope segments for the 2027 GRC period (out of the 49,653 segments identified in DIMP's 3,545 mitigation analysis jobs totaling approximately 2,000 miles) by Risk of Failure score, considering only threats mitigable by pipeline replacement, in descending order. The Commission can then determine an appropriate level of risk reduction warranted by replacement pace, based on transparent leakage and consequence data rather than PG&E's internal targets.

For plastic pipelines, TURN therefore recommends that PG&E replace the blunt pre-1985 cutoff with sub-decade, age-of-manufacture cohorts in its DIMP model and re-run the analysis, which would reveal that a narrow subset of early-vintage Aldyl-A—particularly 1967–1971—drives a disproportionate share of leak risk and offers materially higher benefit-to-cost replacement opportunities than PG&E's undifferentiated MAT 14D replacement pace.

Table 10: Aldyl-A Leak Risk by Sub-Decade Installation Cohort (1967-1991): Evidence for Targeted MAT 14D Replacement[48]

Installation period	Mileage	Avg leak rate (leaks/mi/yr)
1967–1971	96.3 miles	0.42008
1972–1976	1,445.8 miles	0.05715
1977–1981	1,074.8 miles	0.05050
1982–1986	813.1 miles	0.03286
1987–1991	615.5 miles	0.01476

1.b. Division-Specific Risk Disaggregation and Geographic Targeting

TURN recommends PG&E provide segment-level mitigation analysis by division and census tract, showing existing RoF by each of the 8 threat categories, and projected post-replacement risk reduction for each geographic area. These risk data may additionally be overlaid on SB 1221

[48] For steel pipelines, PG&E should similarly replace the blunt pre-1941 cutoff with vintage-specific, mileage-weighted risk analysis in DIMP

neighborhood decarbonization zone boundaries to identify areas with high pipeline risk and foreseeable electrification opportunities within the Commission's identified 151 census tracts across California. This enables the Commission to assess whether replacement capital is allocated to the highest-risk populations and communities and whether risk reduction benefits warrant pipeline replacement.

1.c. Post-Implementation Risk Verification and Performance Monitoring

TURN recommends PG&E provide: (1) quantified estimates of risk reduction and residual RoF for each year 2027–2030; (2) re-runs of the DIMP model post-replacement to verify whether actual risk reduction matches projections[49]; (3) a posteriori calibration of DIMP / RiskFinder model weightings to align with actual risk reduction; and (4) comparison of achieved risk reduction per capital dollar to the baseline (no-action) scenario and alternative replacement strategies. Performance may be annually reported to the Commission.

VI. CONCLUSION

TURN recommends that the Commission reject PG&E’s pace-based replacement strategy and (1) adopt a risk-aligned replacement mileage forecast for all three replacement programs for the 2027 GRC period; (2) adopt TURN’s corrected unit costs for all three replacement programs; and (3) direct PG&E to develop a DIMP-informed, segment-level replacement plan for its 2031 GRC application with geographic risk transparency and post-implementation verification., TURN’s showing demonstrates that even under PG&E’s own RiskFinder / DIMP results—which TURN identifies as overstating risk for broad vintage cohorts through key modeling and weighting flaws—PG&E still does not use DIMP/RiskFinder outputs to set replacement scope or pace for its 2027 GRC forecast. The Commission should therefore require PG&E to use its risk model outputs as the basis for replacement planning and to verify, through periodic re-runs and calibration, that forecast risk reductions are actually achieved.

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[49] While 49 CFR §192.1015(b)(6) establishes a **minimum five-year** reevaluation requirement for DIMP, it expressly ties evaluation frequency to pipeline complexity and changes in risk factors; therefore, the Commission may require **more frequent (e.g., annual) DIMP re-runs** to incorporate performance monitoring results and verify that projected risk reductions are realized in practice.

Attachment 1: STATEMENT OF QUALIFICATIONS OF JALAL AWAN, PH.D.

I am a full-time Energy and Climate Policy Analyst at The Utility Reform Network (TURN) since November 2023 and have sponsored or co-sponsored testimony in various Commission proceedings on behalf of TURN, including PG&E's Updated Peak Day Supply Standard Application (A.24-07-020), Southern California Edison's 2025 GRC Application (A.23-05-010), SCE's Building Electrification Application (A.21-12-009), Pacific Gas and Electric company's 2024 RAMP Application (A.24-05-008), PG&E's Gas AMI Application (A.24-03-011), PG&E's CSUMB Electrification Application (A.22-08-003) and several ongoing CPUC proceedings such as the Long Term Gas Planning OIR (R.24-09-012). Prior to joining TURN, I worked as an Assistant Policy Researcher at the RAND Corporation in Santa Monica (2017-2023) and as an electrical projects engineer at Engro Corporation in Pakistan (2010-2014 and 2016-2017).

As a policy researcher, I have developed technical reports, conducted mixed-methods research, and presented findings to a diverse range of stakeholders, including the Centers for Disease Control and Prevention and the U.S. National Academy of Sciences (NAS). I completed my B.S in electrical power systems engineering from the University of Engineering and Technology, Lahore (Pakistan) from 2006-2010, my M.S. in green technologies from the University of Southern California (Viterbi School of Engineering) in December 2015 as a Fulbright Scholar, and my M.Phil. and Ph.D. in Policy Analysis at the Pardee RAND Graduate School in 2019 and 2023, respectively. I am a member of IEEE, Six Sigma Green Belt from the American Society for Quality (ASQ) and hold the U.S. Green Building Council certification in Leadership in Energy & Environmental Design (LEED).

My Google Scholar profile can be accessed here:

https://scholar.google.com/citations?user=0A3_DZUAAAAJ&hl=en