Application: 23-06-008
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Exhibit No.: (PGE-21)
Date: October 1, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

WILDFIRE AND GAS SAFETY COSTS

TRACK 2

GAS SAFETY AND ELECTRIC MODERNIZATION COSTS

REBUTTAL TESTIMONY

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CHAPTER 1
INTRODUCTION AND INCREMENTALITY

A. Introduction [Witness: Gregory Holisko]

Q 1 What is the purpose of this rebuttal testimony?

A 1 This testimony responds to the testimony submitted by the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), Energy Producers and Users Coalition (EPUC), and Indicated Shippers (IS) regarding Pacific Gas and Electric Company's (PG&E) request for reasonableness review of $116 million in expenses and $118 million in capital expenditures recorded in nine Gas Transmission and Storage (GT&S) memorandum and balancing accounts and four Electric Distribution memorandum accounts representing multiple Gas Safety and Electric Modernization (GSEM) programs.

This testimony also responds to intervenors' recommended disallowances on the grounds that certain activities or costs are not incremental to PG&E's 2020 General Rate Case (GRC) or its 2019 GT&S Rate Case. Chapter 2 will address in detail EPUC/IS's separate contentions that certain costs are not just and reasonable.

Q 2 What is PG&E's request and what are intervenors' recommendations?

A 2 Tables 1-1 and 1-2 summarize PG&E's request for reasonableness review and Cal Advocates' and EPUC/IS's respective recommended amounts for recovery. Additionally, EPUC/IS argues that PG&E has not clearly demonstrated that any of the costs are incremental and recommends the California Public Utilities Commission (CPUC or Commission) Commission reject PG&E's request in its entirety. This recommendation is not reflected in Tables 1-1 or 1-2.

TABLE 1-1
SUMMARY OF INTERVENOR RECOMMENDATIONS – EXPENSES
(THOUSANDS OF DOLLARS)

				Cal Advocates' Recommended Disallowances	
Line No.	Chapter No.	Account	PG&E Expenses[a]	Amount	% of PG&E Request
1	2	In Line Inspection Memorandum Account (ILIMA)	$87,560	$(26,983)	(31)%
2	2	Internal Corrosion Direct Assessment Memorandum Account (ICDAMA)	1,083	(468)	(43)%
3	2	Gas Statutes, Rules, and Regulations Memorandum Account (GSRRMA)	9,721	–	–
4	2	Transmission Integrity Management Program Memorandum Account (TIMPMA)	317	–	–
5	2	Critical Documents Program Memorandum Account (CDPMA)	1,893	–	–
6	2	Gas Storage Balancing Account (GSBA)	8,637	(2,009)	(23)%
7	3	Avoided Cost Calculator Update Memorandum Account (ACCUMA)	207	–	–
8	3	Distribution Resources Plan Tools Memorandum Account (DRPTMA)	4,814	–	–
9	3	Distributed Energy Resources Distribution Deferral Account (DERDDA)	1,623	–	–
10		Totals	$115,855	$(29,460)	(25)%

(a) Amounts presented reflect PG&E’s 7/31/24 Errata filing.

TABLE 1-2
SUMMARY OF INTERVENOR RECOMMENDATIONS – CAPITAL EXPENDITURES
(THOUSANDS OF DOLLARS)

				Cal Advocates' Recommended Disallowances		EPUC/IS' Recommended Disallowances	
Line No.	Chapter No.	Account	PG&E Capital Expenditures[a]	Amount	% of PG&E Request	Amount	% of PG&E Request
1	2	Gas Statutes, Regulations, and Rules Memorandum Account (GSRRMA)	$1,008	–	–	–	–
2	2	Measurement and Control Station Over Pressure Protection Memorandum Account (MCOPPMA)	13,949	$(631)	(5)%	$(12,240)	(88)%
3	2	Gas Storage Balancing Account (GSBA)	92,650	(14,522)	(16)%	(44,000)[b]	(47)%
4	2	Line 407 Memorandum Account (L407MA)	160	–	–	–	–
5	2	Dairy Biomethane Pilot Memorandum Account (DBPMA)	3,020	(256)	(8)%	–	–
6	3	Distribution Resources Plan Tools Memorandum Account (DRPTMA)	2,896	–	–	–	–
7	3	AB 841 Transportation Electrification Memorandum Account (AB841MA)	4,156	–	–	–	–
8		Totals	$117,839	$(15,409)	(13)%	$(56,240)	(48)%

(a) Amounts presented reflect PG&E's 7/31/24 Errata filing.

(b) As discussed in Chapter 2, Section D.4, the $44 million reduction in MAT Code 3L4 costs under the GSBA recommended by EPUC/IS exceeds the $21.1 million of 2022 capital expenditures PG&E is requesting to recover in MAT Code 3L4 in this application.

Q 3 What does PG&E request that the CPUC do with respect to this application?

A 3 PG&E requests that the Commission: (1) find that the costs requested in this application are reasonable and have not been recovered through other cost recovery proceedings, and (2) approve PG&E's requested revenue requirement.

B. Discussion

1. The Commission Should Approve PG&E's Cost Recovery Requests

Q 4 Should the Commission approve PG&E's Cost Recovery Requests?

A 4 Yes. First, all costs for which PG&E is seeking cost recovery were recorded in accounts mandated by the Commission and for which no revenue requirement was provided elsewhere.[1,2,3] Second, PG&E demonstrates in its opening testimony and rebuttal testimony that the costs recorded to these accounts are just and reasonable.

Q 5 Are there any accounts included in this application that were not specifically contested?

A 5 Yes. Aside from EPUC/IS's recommendation that all costs be disallowed in their entirety, no party recommended specific reductions in the following accounts for Gas Operations: CDPMA; GSRRMA; L407MA; TIMPMA. No party recommended specific reductions to any of the Electric Operations included in this application, including the following: AB841MA; ACCUMA; DERDDA; DRPTMA.

Q 6 Should the Commission adopt Cal Advocates' and EPUC/IS's disallowance recommendations?

A 6 No. PG&E's activities and associated costs are reasonable and consistent with sound utility practices, law, and Commission policy. Although Cal Advocates recommends certain disallowances, they generally do not challenge the necessity of the activities under review in this proceeding. PG&E disagrees with Cal Advocates' proposed disallowances for

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1 PG&E-2, Ch. 2, pp. 4-13, Reasonableness of Costs (Gas Accounts).

2 PG&E-2, Ch. 3, pp. 2-18, Project Overview (Electric Accounts).

3 While GSBA does have a revenue requirement included in the GT&S, this case is to perform a reasonableness review of all 2022 costs and to recover the spend above the balancing account revenues. See Chapter 2, section D.4.

straight-time labor and materials movement on the grounds that such costs are not incremental and addresses this argument in its discussion of incrementality in Section C of this chapter. PG&E also addresses EPUC/IS's overbroad argument that it has not demonstrated that any of the costs included in this proceeding are incremental in Section C.

Q 7 How does PG&E respond to customer affordability concerns?

A 7 We recognize the burden on our customers stemming from the costs associated with implementing our risk mitigation and compliance activities and other customer-focused initiatives. This recognition drives our constant efforts to make each of our programs targeted, efficient, and sustainable. Ultimately, the work at issue here involves necessary investments for safe and reliable gas and electric systems, consistent with Commission policy and directives, and state law.

C. Incrementality [Witness: Matt Devita]

Q 8 Please summarize PG&E's position with respect to incrementality.

A 8 PG&E's position with respect to incrementality includes the following key points:

- All costs for which PG&E is seeking cost recovery were recorded in accounts mandated by the Commission and for which no revenue requirement was provided elsewhere;[4]
- The Utility Audits Branch (UAB) of the CPUC reviewed the GSEM costs to determine whether they are "sufficiently supported, incremental …, [and] directly attributable to allowable activities in the designation accounts…."[5] The UAB did not recommend any reductions related to incrementality; and
- Cal Advocates' proposals related to straight time labor and materials movement disregard that PG&E's forecasting methodologies are activity based, rather than based on specific employees or materials. As explained below, these costs are not already recovered elsewhere, and Cal

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4 While GSBA does have a revenue requirement included in the GT&S, this case is to perform a reasonableness review of all 2022 costs and to recover the spend above the balancing account revenues. See Chapter 2, section D.4.

5 Utility Audits, Risk and Compliance Division, UAB, Gas Safety and Electric Modernization Expenditures Performance Audit (July 11, 2024), p. 1.

Advocates' position would be infeasible for the efficient and cost-effective operations of the utility.

1. Summary of Intervenor Recommendations

Q 9 Please summarize Cal Advocates' and EPUC/IS's incrementality-based recommendations.

A 9 Tables 1-1 and 1-2 summarize the total reductions recommended by Cal Advocates and EPUC/IS. Cal Advocates argues that straight-time labor and materials movement costs are not incremental and should be disallowed. EPUC/IS argues that PG&E has not proven the incrementality of any of the GSEM costs included in this proceeding.

Q 10 What is Cal Advocates' position on straight-time labor?

A 10 Cal Advocates recommends the disallowance of straight-time labor costs associated with incremental activities at issue in this proceeding, contending that PG&E has not proven that it hired additional personnel earmarked for the gas programs in question.[6]

Q 11 What is the reasoning behind Cal Advocates' straight-time labor incrementality recommendation?

A 11 Cal Advocates argues that PG&E's 2020 GRC and 2019 GT&S decisions funded all of PG&E's labor requirements for the rate case cycle, even for those gas programs the Commission specifically directed PG&E to remove from GT&S and establish memorandum or balancing accounts for. It then concludes that, unless PG&E can show that it hired specific personnel for each program, the labor costs associated with these programs are not incremental.

Q 12 Does PG&E agree with Cal Advocates' recommendation?

A 12 No. To adopt Cal Advocates' approach would require PG&E to hire new and different employees to work on each of its incremental gas programs to justify their associated straight-time labor costs. This would be extremely inefficient and costly. Cal Advocates' recommendation would be reasonable only if PG&E forecast its GRC and GT&S base work by resource (e.g., cost of a specific employee) instead of by activity (e.g., cost to complete a gas safety project).

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6 Cal Advocates-05, p. 7, lines 5-18.

Consistent with industry standard practices and cost accounting principles, PG&E's forecasting methodologies are activity-based, presenting labor costs in the context of the program or project PG&E intends to execute. The labor cost of specific employees is not forecast for in the GRC, GT&S, or elsewhere; only the cost of having a non-specific employee perform a GRC- or GT&S-forecasted activity is included in those proceedings.

Since PG&E did not forecast for or receive cost recovery for the straight-time labor costs it reasonably incurred during completion of the projects tracked in the GSEM accounts at issue here in any other proceeding, straight-time labor recorded to these accounts should be treated as incremental.

Q 13 Please explain what is meant by "materials movement"?

A 13 PG&E defines materials movement as the transfer of bulk, pre-purchased materials inventory for use during the execution of a project or process. PG&E acquires materials in large quantities and holds them in warehouses until they are required at a project site; it initially records these costs as inventory (a current asset on its balance sheet) and does not seek recovery for them at the point of purchase. When the materials are used during a project or process, PG&E records (debits) the cost of the materials used to the work order associated with that specific project and reduces (credits) the amount from its inventory account. Only after materials are used and recorded to a work order as materials movement does PG&E include the cost as expense or capital expenditure in the appropriate memorandum or balancing accounts for potential recovery in rates.

Q 14 What is Cal Advocates' position on materials movement?

A 14 Cal Advocates states that materials movement costs are not incremental because PG&E did not purchase additional materials when the utility moved pre-purchased materials from warehouses to staging sites.[7]

Q 15 Is Cal Advocates correct in asserting that the costs of materials movement are recovered elsewhere?

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[7] Cal Advocates-05, p. 5, line 18 to p. 6, line 7.

A 15 No, the costs of the materials movement for the gas and electric programs included in this proceeding are not included in the revenue requirement of any other rate case. As with the total cost of straight-time labor, PG&E's total cost of materials movement is not forecasted for in the GRC or elsewhere. As stated previously, PG&E's forecasts are activity-based: only the cost of materials movement that PG&E expects to incur in the context of completing GRC or GT&S activities are forecasted for in those rate cases. Furthermore, Cal Advocates' apparent position that PG&E should purchase materials for projects recorded to memorandum accounts separately from other materials is infeasible for the efficient operations of the utility is and is likely to result in higher costs to customers, compared to pre-purchasing materials in bulk.

Q 16 What is EPUC/IS's argument regarding the incrementality of these costs?

A 16 In its testimony, EPUC/IS argues that,

> PG&E's claim of incremental expenses and capital items has simply not been demonstrated to be reasonable.[8]

It claims that PG&E provided no evidence that it did not decrease spending in other areas during its last GRC and that, without evidence of its total costs (both those included in this proceeding and in its GRC), that PG&E has not demonstrated the incrementality of any of the gas and electric accounts at issue here.

Q 17 How does PG&E respond?

A 17 PG&E disagrees with EPUC/IS's interpretation of how incrementality is established and the type of proof needed to determine it. By stating that PG&E must provide evidence of its total costs, EPUC/IS implies that any underspend of forecasted costs authorized for recovery in PG&E's GRC or GT&S should be considered to offset the costs included in this proceeding before the GSEM costs at issue should be deemed incremental. This method for determining incrementality is illogical and not in-keeping with the Commission's decisions requiring that PG&E establish these memorandum and balancing accounts to track the costs incurred for GSEM programs separately.

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[8] EIS-02, p. 8, lines 3-7.

Q 18 Does EPUC/IS cite additional third-party evidence to support its position?

A 18 Yes. EPUC/IS cites the audit of GSEM accounts performed by UAB.

Q 19 Did the UAB audit include an analysis of incrementality in its scope?

A 19 Yes, it did.

Q 20 Did the UAB audit find that the entirety of GSEM costs were not incremental?

A 20 No, it did not. The UAB did not recommend any reductions related to incrementality. Rather, the UAB identified four findings of overstated or unsubstantiated costs; it recommended that PG&E remove approximately $4.5 million from its revenue requirement via its errata filing. PG&E agreed with all but one of the UAB's findings and included a reduction of more than $4 million in errata filed on July 31 to incorporate UAB recommendations.

Q 21 Does EPUC/IS propose any alternative disallowances of PG&E's GSEM costs?

A 21 Yes. As an alternative to total disallowance, EPUC/IS recommends a reduction of $44 million of capital expenditures recorded to the GSBA and of $12.24 million of capital expenditures recorded to the Measurement and Control Station Overpressure Protection Memorandum Account (MCOPPMA).

Q 22 What is the basis for EPUC/IS's recommendation with respect to the GSBA?

A 22 EPUC/IS contends that PG&E overspent significantly on the Whiskey Slough and Turner Cut repair and replace projects and should be disallowed $44 million as result.[9] However, as PG&E demonstrates in its opening testimony and this rebuttal testimony, EPUC/IS's recommendations are beyond the scope of this application since PG&E is only seeking $21.1 million (not $44 million) of costs incurred in 2022 for these projects. Furthermore, PG&E explains that costs were driven by emerging regulations, additional scope, and construction pricing increases and therefore reasonably incurred. See Chapter 2, Part D, Section 4 of PG&E's rebuttal testimony for PG&E's detailed response regarding capital expenditure related to Whiskey Slough and Turner Cut projects.

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9 EIS-02, p. 13, lines 8-10.

Q 23 What is the basis for EPUC/IS's recommendation with respect to the MCOPPMA?

A 23 EPUC/IS contends that PG&E's costs for the Overpressure Protection Program recorded in the MCOPPMA exceeded the amount approved by the Commission, was beyond the scope approved by the Commission, and was unreasonable in other respects. However, as PG&E demonstrates in its opening testimony and this rebuttal testimony, the Commission approved no prior funding for this program, and the work PG&E performed was at a reasonable cost and within the scope of the program. See Chapter 2, Part D, Section 3 of PG&E's rebuttal testimony for PG&E's detailed response.

D. Conclusion

Q 24 Please summarize the conclusions the Commission should reach regarding PG&E's demonstration of incrementality.

A 24 The Commission should reject intervenors' proposed disallowances. PG&E has established the incrementality of the costs at issue here because: (1) PG&E has provided clear explanations of how its straight-time labor and materials movement costs recorded to its GSEM accounts are incremental to this proceeding and not forecasted for or recovered as part of the 2020 GRC or 2019 GT&S rate cases; (2) PG&E corrected the misunderstanding implicit in EPUC/IS's recommendation that costs outside the scope of this proceeding must be considered in determining incrementality of GSEM costs; (3) the CPUC's own UAB issued a final audit report which did not include any recommended disallowances on the grounds of incrementality.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

GAS OPERATIONS

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CHAPTER 2
GAS OPERATIONS

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 This testimony is sponsored by various Gas Operations witnesses, identified in each section below.[1] This testimony responds to the direct testimony of the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and Energy Producers and Users Coalition (EPUC) and Indicated Shippers (IS).

B. Summary of Issues

Q 2 Please identify the memorandum and balancing accounts this chapter addresses.

A 2 This chapter addresses the following accounts that were disputed by intervenors:

TABLE 2-1
SUMMARY OF MEMORANDUM AND BALANCING ACCOUNTS AND REBUTTAL TESTIMONY REFERENCE

Line No.	Memorandum and Balancing Account	Rebuttal Testimony Section Addressing
1	In-Line Inspection Memorandum Account (ILIMA)	D.1
2	Internal Corrosion Direct Assessment Memorandum Account (ICDAMA)	D.2
3	Measurement and Control Station Overpressure Protection Memorandum Account (MCOPPMA)	D.3
4	Gas Storage Balancing Account (GSBA)	D.4
5	Dairy Biomethane Pilot Memorandum Account (DBPMA)	D.5

C. Summary of Intervenor Recommendations for Gas Accounts

Q 3 Please provide a summary of Cal Advocates' position related to the Gas Accounts presented in Track 2 to which you will be responding.

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1 See Appendix A for the Statement of Qualifications for Pacific Gas and Electric Company (PG&E) witnesses.

A 3 Of the Gas Accounts presented in Track 2 of this proceeding, Cal Advocates recommends recovery of approximately $79.75 million in expenses, which is $29.46 million less than PG&E's expense request of $109.21 million. Please see Rebuttal Chapter 1, Table 1-1 lines 1, 2, and 6. Cal Advocates separately recommends recovery of approximately $95.38 million in capital, which is $15.41 million less than PG&E's capital request of $110.79 million. Please see Rebuttal Chapter 1, Table 1-2 lines 2, 3, and 5. Cal Advocates recommends disallowances for the following categories of costs, which Cal Advocates contends are not incremental:

- Straight-Time (ST) Internal Labor; and
- Materials Movement.

Q 4 Please provide a summary of EPUC/IS's position related to the Gas Accounts presented in Track 2 to which you will be responding.

A 4 EPUC/IS makes two alterative recommendations. First, EPUC/IS recommends that the California Public Utilities Commission (CPUC or Commission) should reject PG&E's Application "in its entirety," as PG&E has "failed to prove that it has not fully recovered all the total Operations & Maintenance expenses and capital items in this filing versus what it proposes to characterize as incremental."[2] Second, in the event the Commission rejects EPUC/IS's first recommendation, EPUC/IS recommends recovery of approximately $54.55 million in capital, which is $56.24 million less than PG&E's capital request of $110.79 million. Please see Rebuttal Chapter 1, Table 1-2, lines 2 and 3.

Q 5 How do you respond to EPUC/IS's argument that the costs PG&E seeks to recover should be disallowed "in their entirety"?

A 5 Costs presented by PG&E in Track 2 are incremental and reasonable for recovery. Please see Chapter 1, Part C of PG&E's rebuttal testimony for discussion regarding incrementality. The remainder of this Chapter responds to Cal Advocates' recommendations, and EPUC/IS's alterative recommendation to disallow $54.55 million of capital.

Q 6 Are there gas balancing or memorandum accounts that parties do not dispute or do not address?

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2 EIS-02, p.10, lines 9-17.

A 6 Yes, Cal Advocates does not oppose and EPUC/IS made no recommendations specific to PG&E's costs in the following memorandum accounts:

- Gas Statutes Regulations and Rules Memorandum Account;
- Transmission Integrity Management Program Memorandum Account;
- Critical Documents Program Memorandum Account; and
- Line 407 Memorandum Account.

Q 7 Please provide PG&E's current costs and intervenor recommendations.

A 7 PG&E's recorded costs by memorandum and balancing account and the parties' recommendations are set forth in Table 2-2 (expense) and Table 2-3 (capital expenditures) below.

TABLE 2-2
ADJUSTED RECORDED EXPENSES AND PARTIES RECOMMENDATIONS
(THOUSANDS OF NOMINAL DOLLARS)

			Adjusted Recorded[a]	Cal Advocates	EPUC/IS
Line No.	Account	Maintenance Activity Type(s) (MAT)	2022 Adj. Recorded	2022 Increases/ (Reductions)	2022 Increases/ (Reductions)
1	ILIMA	HPI, HPB, HPR	$87,560	$(26,983)	–
2	ICDAMA	HPJ, HPO	1,083	(468)	–
3	GSBA	AH#, AH1, AH2, AH3	8,637	(2,009)	–
4	Total		$97,281	$(29,460)	–

(a) PG&E's 2022 adjusted recorded costs reflect errata as of July 31, 2024.

TABLE 2-3
ADJUSTED CAPITAL EXPENDITURES AND PARTIES RECOMMENDATIONS
(THOUSANDS OF NOMINAL DOLLARS)

			Adjusted Recorded[a]	Cal Advocates	EPUC/IS
Line No.	Account	MAT(s)	2022 Adj. Recorded	2022 Increases/ (Reductions)	2022 Increases/ (Reductions)
1	MCOPPMA	76G	$13,949	$(631)	$(12,240)
2	GSBA	3L1, 3L3, 3L4, 3L5	92,650	(14,522)	–
3	GSBA	3L4	21,064	–	(44,000)[d]
4	DBPMA	26A	3,020[b]	(256)	–
5	Total		$109,625[c]	$(15,409)	$(56,240)

(a) PG&E's 2022 adjusted recorded costs reflect errata as of July 31, 2024.

(b) The recorded capital expenditures for the DBPMA included costs from 2019-2022.

(c) The total recorded capital expenditures include 2022 recorded costs for the MCOPPMA and GSBA as well as 2019-2022 recorded costs for the DBPMA (line 1 + line 2 + line 4).

(d) As discussed in Section D.4, the $44 million reduction in the GSBA exceeds the $21.1 million of the 2022 costs PG&E is requesting to recover in this MAT Code.

D. PG&E's Response to Parties' Positions

1. ILIMA [Witness: Chris Warner]

Q 8 Briefly, what is the scope of the ILIMA?

A 8 The ILIMA is an account established during the 2019 Gas Transmission & Storage (GT&S) Rate Case period (2019-2022) pursuant to CPUC Decision (D.) 19-09-025 (2019 GT&S Decision).

The purpose of the ILIMA is to track the revenue requirement associated with the actual capital expenditures for Traditional In-Line Inspection (ILI) upgrade projects above the total of 48 adopted projects (12-project,-per-year pace for each of the years in the 2019 GT&S period) and actual expenses incurred for Traditional and non-Traditional re-assessment ILI runs and Direct Examination and Repair resulting from the reassessment runs.

All of PG&E's request for ILIMA in this proceeding is related to ILI reassessments.

In this proceeding, PG&E is seeking recovery of approximately $87.6 million for costs incurred in 2022 for ILI reassessment activities recorded in the ILIMA.[3]

Q 9 Did PG&E receive any recovery in the 2019 GT&S Rate Case decision for 2022 ILI reassessments?

A 9 No. The 2019 GT&S Decision, which directed the creation of the ILIMA, did not provide prior recovery of these costs. Specific to the reassessments, the 2019 GT&S Decision found they may still be performed and are permitted to be tracked in the ILIMA to be submitted in a future rate case for reasonableness review.[4] The request in this proceeding is in accordance with the 2019 GT&S Decision.

3 PG&E-2 (July 31, 2024), p. 2-AtchA-3, lines 17-18.

4 D.19-09-025, p. 331, Ordering Paragraph (OP) 63.

Q 10 Which parties commented on the ILIMA?

A 10 Cal Advocates addressed this account.

Q 11 What is Cal Advocates' position?

A 11 Cal Advocates recommends the Commission reduce PG&E's recoverable expenses amount in the ILIMA by $26.9 million. Cal Advocates' recommended adjustments are comprised of the following: ST Labor costs totaling $19.2 million and Materials Movement costs totaling $7.7 million.[5] Cal Advocates states these costs are not incremental.

Q 12 Do you agree with Cal Advocates' position?

A 12 No, PG&E does not support Cal Advocates' position on this issue. Please see Chapter 1, Part C of PG&E's rebuttal testimony for discussion regarding the incrementality of Materials Movement and ST Labor costs recorded in the ILIMA.

Q 13 In closing, what does PG&E recommend?

A 13 PG&E recommends the Commission find reasonable PG&E's recorded expenses of $87.5 million in the ILIMA in full.

2. ICDAMA [Witness: Chris Warner]

Q 14 Briefly, what is the scope of the ICDAMA?

A 14 The ICDAMA is an account established pursuant to the 2019 GT&S Decision for the Internal Corrosion Direct Assessment (ICDA) sub-program of the Transmission Integrity Management Program Balancing Account.

The purpose of the ICDAMA memorandum account is for the ICDA sub-program to track costs for integrity assessments for the internal corrosion threats that are required under Subpart O. The Commission ordered that the costs recorded in the ICDAMA be subject to reasonableness review.

In this proceeding, PG&E is seeking recovery of approximately $1.08 million for expense costs incurred in 2022 for activities recorded in the ICDAMA.[6]

Q 15 Did PG&E receive any recovery in the 2019 GT&S Rate Case decision for 2022 ICDA assessments?

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5 Cal Advocates-05, p. 5, lines 12-16.

6 Cal Advocates-05, p. 8, lines 3-4.

A 15 No. The 2019 GT&S Decision directed PG&E to track the costs of ICDA assessments in the ICDAMA to be submitted in a future rate case for reasonableness review.[7] The request in this proceeding is in accordance with the 2019 GT&S Decision.

Q 16 Which parties commented on the ICDAMA?

A 16 Cal Advocates addressed this account.

Q 17 What is Cal Advocates' position?

A 17 Cal Advocates recommends the Commission reduce PG&E's recoverable amount in the ICDAMA by $0.468 million.[8] This amount is related to Materials Movement costs which Cal Advocates states are not incremental.

Q 18 Do you agree with Cal Advocates' position?

A 18 No, PG&E does not support Cal Advocates' position on this issue. Please see Chapter 1, Part C of PG&E's rebuttal testimony for discussion regarding the incrementality of Materials Movement costs recorded in the ICDMA.

Q 19 In closing, what does PG&E recommend?

A 19 PG&E recommends the Commission find reasonable PG&E's recorded expenses of $1.08 million in the ICDAMA in full.

3. MCOPPMA [Witness: Karli Maeda]

Q 20 Briefly, what is the MCOPPMA?

A 20 The MCOPPMA creation was ordered by the CPUC in the 2019 GT&S Decision.[9] The purpose of the MCOPPMA is to track the revenue requirement associated with actual capital expenditures for the Gas Transmission (GT) M&C Station Over Pressure Protection (OPP) Program during the 2019 GT&S rate case cycle. The GT Station OPP Enhancements capital program that is subject to the MCOPPMA includes capital projects for modifying or adding station equipment to provide protection against large overpressure events. The MCOPPMA is more fully discussed in PG&E's opening testimony.[10]

Q 21 What type of work is included in the memorandum account?

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7 D.19-09-025, p. 331, OP 64.

8 Cal Advocates-05, p. 8, lines 15-19.

9 D.19-09-025, p. 331, OP 62.

10 PG&E-2 (July 31, 2024), Ch. 2, Attachment E.

A 21 The five main categories of work included in the MCOPPMA are: (1) Large Volume Customer Regulator (LVCR) sets rebuilds; (2) LVCR retrofits; (3) Large Volume Customer Meter (LVCM) sets rebuilds; (4) LVCM retrofits; and (5) simple stations retrofits.[11]

Q 22 Cal Advocates proposes a reduction of approximately $0.631 million of capital expenditures related to Materials Movements, which they argue is not incremental.[12] Do you agree with Cal Advocates' position?

A 22 No, PG&E does not support Cal Advocates' position on this issue. Please see Chapter 1, Part C of PG&E's rebuttal testimony for discussion regarding the incrementality of Materials Movement costs recorded in MCOPPMA.

Q 23 Please summarize EPUC/IS's arguments.

A 23 EPUC/IS recommends a $12.24 million capital disallowance because:

1) PG&E exceeded costs "approved" by the Commission for this program;[13]
2) Rebuilding regulator stations is not within the scope of the program;[14]
3) Unit costs are too high;[15] and
4) Costs for engineering and design work for projects with execution in the future are "irrelevant."[16]

PG&E addresses each of these arguments below.

Q 24 How do you respond to EPUC/IS's contention that $6.1 million was approved by the Commission for this program?

A 24 As discussed in opening testimony[17] and in data requests,[18] the Commission did not approve the $6.1 million forecast presented in the 2019 GT&S rate case. Instead, the Commission ordered, in the 2019 GT&S

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11 PG&E-2 (July 31, 2024), p.2-AtchE-3, lines 9-13; 20-25.

12 Cal Advocates-05, p. 10, lines 17-18.

13 EIS-02, p.13, line 14-17; p.14, lines 12-14.

14 EIS-02, p.14, lines 2-7.

15 EIS-02, p.13, line 20 to p. 14, line 2.

16 EIS-02, p.14, lines 10-12.

17 PG&E-2 (July 31, 2024), p. 2-AtchE-1, lines 8-14, and p. 2-AtchE-5, lines 14-24.

18 PG&E's response to Data Request Joint-EI_003-Q001, dated 8/22/2024 in Attachment L.

Decision,[19] the creation of the MCOPPMA to track the capital expenditures related to the OPP program.

Q 25 How do you respond to EPUC/IS's contention that rebuilding regulator stations is not within the scope of the program?

A 25 While it is true the 2019 GT&S forecast for this program only included retrofit activities at GT simple and complex stations, those forecasts were high-level and that the program was new. In the 2019 GT&S Decision, the Commission summarized the early evolution of the program by saying:

> However, PG&E's vision of the program appears to be in flux. …Thus, while we encourage PG&E to continue to evaluate the best methods to manage overpressure incidents on its system, we find that requiring PG&E to track capital expenditures for this program in a memorandum account is appropriate until a firmer understanding of necessary activities and projects and the associated project costs can be forecast with a reasonable degree of accuracy.[20]

Changes and continuous improvement of approaches are in-line with the directive of the Commission that PG&E "continue to evaluate the best methods." PG&E's OP Elimination Program Long-Term (LT) Execution Plan[21] (referenced in opening testimony[22] and provided in a data response)[23] outlines the program development and execution plan. The evolution of the program to include LVCs and regulator stations rebuild was also presented in the 2023 General Rate Case (GRC) Track 2 proceeding.[24]

Q 26 How do you respond to EPUC/IS's contention that unit costs are too high and that $12.24 million were spent on only seven stations?

A 26 EPUC/IS identified that $12.24 million was spent in 2022 on LVCR rebuilds and retrofits, but incorrectly associated those costs with only seven stations.

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19 D.19-09-025, p. 331, OP 62.

20 D.19-09-025, p. 111.

21 Excerpt from GP-1104, Appendix M: Spec Services, Overpressure Elimination Program, Summary of Program Development and LT Execution Plan, Rev 3 (July 2022), in Attachment K.

22 PG&E-2 (July 31, 2024), p. 2-AtchE-2, lines 16-17.

23 PG&E's response to Data Request CalAdvocates_008-Q005, dated 10/25/2023 in Attachment J.

24 A.21-06-021, Exhibit (PG&E-80), Ch. 2, Attachment E.

PG&E's workpapers (WP)[25] show that the 2022 recorded costs of $12.24 million include cost for operational, engineering and closeout stages on a total of 58 LVCR rebuilds and retrofits. The seven stations mentioned by EPUC/IS are the LVCR rebuilds and retrofits made operational in 2022, which had total associated spend in 2022 of $7.3 million, not $12.24 million. On average, this is $1.0 million per station spent in 2022, and not $1.6 to $1.8 million stated by EPUC/IS. Moreover, EPUC/IS's calculation does not yield a true unit cost. Most projects span multiple years, including prior years that were already subject to cost recovery as part of the 2023 GRC Track 2 proceeding, and a true unit cost calculation would need to include those costs. Thus, EPUC/IS's claim that unit costs are too high is factually deficient and not meaningful in the context of the spending at issue in this application, which includes only costs incurred in 2022 for projects that span multiple years.

Q 27 Did EPUC/IS present any evidence that spend recorded in the MCOPPMA was imprudent or unreasonable?

A 27 EPUC/IS did not provide evidence that any specific spending presented in the MCOPPMA was imprudent or unreasonable. This is consistent with Utility Audit Branch's (UAB) conclusions. The objective of the UAB audit was:

> …to determine whether expenditures recorded in the gas safety and electric modernization accounts and included in PG&E's Application (A.) 23-06-008 for cost recovery, are sufficiently supported, incremental in nature, directly attributable to allowable activities in the designated accounts, and in compliance with applicable [Public Utilities] Code sections, CPUC Decisions, PG&E's policies and procedures, and other relevant criteria[26]

For the MCOPPMA account, the UAB identified only a single finding which was adjusted in the errata and is no longer part of the proceeding.

Q 28 How do you respond to EPUC/IS's contention that costs for engineering and design work for project with execution in the future are "irrelevant"?

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25 PG&E-4 (July 31, 2024), WP 2-27, Table 2-23, fn. 3, and WP 2-28 to WP 2-30.

26 Utility Audits Risk and Compliance Division, UAB, Cost Recovery A.23-06-008, Gas Safety and Electric Modernization Expenditures, Performance Audit, (July 11, 2024), p. 6 (citations omitted).

A 28 The engineering and design costs are entirely relevant. Those costs, as well as close-out costs, are all critical and necessary for project execution and are legitimate and eligible for the MCOPPMA account. Similar prior period costs were included for the MCOPPMA in the 2023 GRC Track 2 proceeding and were adopted as recoverable and reasonable in the Commission's final decision.

Q 29 In closing, what does PG&E recommend?

A 29 PG&E recommends the Commission find reasonable PG&E's recorded capital expenditures of $13.9 million in the MCOPPMA in full.

4. GSBA [Witness: Lucy Redmond]

Q 30 Briefly, what is the scope of the GSBA?

A 30 The GSBA was requested by PG&E and adopted by the Commission in PG&E's 2019 GT&S rate case proceeding.[27]

The GSBA was established as a two-way balancing account to manage the forecast discrepancies that result due to the regulatory uncertainty and the complexity inherent to downhole well work. Considering new regulations governing PG&E's gas storage assets were in draft or interim form at the time that PG&E filed the 2019 GT&S application, the pace of work and related expenditures for programs responsible for Major Work Categories 3L and AH could vary after the final regulations were adopted. Further, downhole well work costs are highly variable and dependant on condition of the asset and final scope of work necessary to bring wells back into service following a downhole well condition inspection and conversion to tubing and packer.

The Commission directed that:

> [I]n the next rate case, PG&E shall submit an analysis comparing the total recorded costs with the authorized amount, and the Commission will determine whether the transactions in the balancing account are reasonable.[28]

In this proceeding, PG&E is requesting the Commission find reasonable $8.6 million in expenses and $92.7 million in capital expenditures related to

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[27] A.17-11-009, PG&E-1, p. 6-7, line 20 to p. 6-9, line 14, Section A.5.c.

[28] D.19-09-025, p. 95.

the GSBA in 2022. SInce the GSBA is a two-way account, a portion of the costs at issue are included in the 2019 GT&S revenue requirement and only the amounts above are included in the revenue requirement ask in this proceeding. These equate to a $0.17 million request for additional recovery in expenses[29] and a $62.1 million request for additional recovery in capital expenditures above what was adopted for GSBA in the 2019 GT&S Rate Case decision.[30]

Q 31 Which parties commented on the GSBA?

A 31 Cal Advocates and EPUC/IS both addressed this account.

Q 32 What is Cal Advocates' position?

A 32 Cal Advocates recommends the Commission reduce PG&E's recoverable amount for expense in the GSBA by $2 million.[31] This amount is related to ST labor costs which Cal Advocates states are not incremental.

Cal Advocates also recommends the Commission reduce PG&E's recoverable amount for capital expenditures by $14.52 million.[32] This amount is related to $8.23 million in ST labor costs and $6.3 million in materials movement costs, which Cal Advocates state are not incremental.

Q 33 Do you agree with Cal Advocates' position?

A 33 No, PG&E does not support Cal Advocates' position on these issues. Please see Chapter 1, Part C of PG&E's rebuttal testimony for discussion regarding incrementality of ST labor and materials movement costs recorded in GSBA.

Q 34 What is EPUC/IS's position?

A 34 EPUC/IS recommends the Commission reduce PG&E's recoverable amount for MAT Code 3L4 by $44 million "because of PG&E's undisciplined capital spending and lack of project cost control."[33]

Q 35 Does EPUC/IS explain how they calculated their recommended reduction?

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29 PG&E-2, p. 2-AtchG-5, Table 2G-1.

30 PG&E-2, p. 2-AtchG-5, Table 2G-2.

31 Cal Advocates-05, p. 12, lines 14-17.

32 Cal Advocates-05, p. 12, lines 18-24.

33 EIS-02, p. 11, lines 1-3.

A 35 Yes. EPUC/IS calculated the recommended reduction of $44 million in MAT Code 3L4 by subtracting $9.2 million (the forecast for the Whiskey Slough project in the 2019 GT&S Rate Case) and $7.5 million (the forecast for the Turner Cut project in the 2019 GT&S Rate Case) from the $61 million recorded spend in MAT Code 3L4 from 2019-2022 ($61 million – $9.2 million – $7.5 million = ~$44 million).[34]

Q 36 Is EPUC/IS's recommendation accurately calculated?

A 36 No. EPUC/IS incorrectly calculated the reduction and is making recommendations beyond the scope of this proceeding.

Q 37 What is the error in EPUC/IS's recommendation?

A 37 The $61 million EPUC/IS uses as a foundation for its recommendation includes recorded capital expenditures dating back to 2019. This proceeding is specific to PG&E's recorded capital expenditures in the GSBA for 2022 only. The reasonableness review for 2019–2021 recorded capital expenditures in the GSBA was addressed in the 2023 GRC Track 2.

Q 38 After removing amounts previously addressed in 2023 GRC Track 2, what is the remaining reduction amounts being considered in this proceeding?

A 38 PG&E's recorded capital expenditures for 2022 in MAT Code 3L4 requested in this proceeding are approximately $21.1 million and are primarily related to costs related to the Turner Cut project. The construction on the Whiskey Slough project was complete in 2020. Making a recommendation with respect to costs beyond the scope of this proceeding is not appropriate and should not be considered.

Q 39 Does PG&E provide any drivers for the $21.1 million recorded capital expenditures in MAT Code 3L4 for 2022?

A 39 Yes. In PG&E's opening testimony, PG&E stated:

> The primary driver for the $21.1 million recorded spend is due to the MAT 3L4 pipe replacement projects including: (1) the timeline of planned execution and emerging regulatory requirements; (2) additional scope requirements identified in detailed design phase; and (3) increase in construction contract pricing, offset by efficiencies gained by grouping the project for well control valve installations that were forecast in MAT 3L5 into the station pipe replacement projects in MAT 3L4.[35]

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[34] EIS-02, p. 12, lines 4-5.

[35] PG&E-2, p. 2-AtchG-23, line 8 to p. 2-AtchG-24, line 4.

Q 40 Does EPUC/IS take issue with these drivers?

A 40 Yes. EPUC/IS states PG&E provided:

> [N]o detailed account for the Turner Cut timeline, and PG&E's overspending was even more unbridled given that there were cost efficiencies with MAT 3L5 work.[36]

Q 41 Can you please provide any additional context to the drivers of costs stated in PG&E's opening testimony?

A 41 Yes. The timeline and planned execution of the Whiskey Slough and Turner Cut projects were revised to incorporate emerging regulatory requirements from the California Geologic Energy Management Division (CalGEM).

At the time, the 2019 GT&S Rate Case was filed, it was not anticipated that the project work to replace both the Whiskey Slough and Turner Cut infill pipe (the pipe that goes from the wellheads at each station to the respective platform) would extend into 2022.

Whiskey Slough was planned to be completed in 2018, with the east side completed first, and west side following. Turner Cut's north and south sides were similarly planned to be completed in 2020. However, in 2016, CalGEM began circulating draft regulations and adopted in 2018 regulations that would require California storage operators, including PG&E, to convert wells to dual barrier construction. Starting in 2018, PG&E was required to begin conversion of wells and was no longer permitted to use both casing and tubing annuli in the well to flow the wells, restricting flow to the inner tubing. Due to this change, it was no longer necessary to have two lines from each well to the platform and a single line from the wellhead to platform would be sufficient. This change allowed PG&E to reduce risk and reduce the two lines of pipe that flow gas from a wellhead to the platform down to a single line. However, this change did not reduce costs is a meaningful way due to the need to install a foundation system which was a significant portion of the cost. Additionally, metering run injection and withdrawal measurement that was forecast in 3L5 in the 2019 GT&S was incorporated into each of these 3L4 projects for efficiency.

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[36] EIS-02, p. 13, lines 5-7.

PG&E’s execution timeline due to the redesign and reengineering was pushed back for both- Whiskey Slough and Turner Cut-projects. Whiskey Slough and Turner Cut were planned for execution in consecutive years to maintain deliverability at the McDonald Island facility.

Additionally, in 2019 as the number of well rework projects increased to meet CalGEM regulations the same year, PG&E had to delay the Whiskey Slough West side infill to 2020 to maintain necessary withdrawal capacity through 2019. These combined delays resulted in all projects ultimately being completed in 2022, with Turner Cut South Side Replacement being completed last and included as part of this application.

Please see the table below for planned versus actual construction completion dates of both the Whiskey Slough and the Turn Cut projects.

TABLE 2-4
GAS STORAGE BALANCING ACCOUNT
MAT CODE 3L4 WHISKEY SLOUGH AND TURNER CUT PROJECT TIMELINES
(FORECASTED VS ACTUAL)

Line No.	Project	Forecasted Construction Completion Date[a]	Actual Construction Completion Date
1	Whiskey Slough Station		
2	East Side Replacement	2017	2018
3	West Side Replacement	2018	2020
4	Turner Cut Station		
5	North Side Replacement	2019	2021
6	South Side Replacement	2020	2022

(a) Forecast construction completion dates as shown in PG&E's GT&S Rate Case A.17-11-009.

Q 42 In closing, what does PG&E recommend?

A 42 As described above, PG&E prudently incurred these costs, consistent with Commission direction, and construction delays were primarily due to new CalGEM regulations. Therefore, PG&E recommends the Commission find reasonable PG&E’s recorded expenses of $8.6 million and capital expenditures of $92.7 million in the GSBA in full and grant PG&E recovery of the additional costs above what was adopted for GSBA in the 2019 GT&S Rate Case decision.

5. DBPMA [Witness: John Hunter]

Q 43 Briefly, what is the scope of the DBPMA?

A 43 The DBPMA is an account established pursuant to D.17-12-004, which directed PG&E to establish three separate accounts associated with Diary Biomethane projects.

The DBPMA is used to track eligible PG&E-owned pipeline infrastructure costs associated with Dairy Biomethane Pilot projects.

In this proceeding, PG&E is seeking recovery of approximately $3.02 million associated with the Merced (Customer Energy Efficiency) Dairy Pilot Project, which was the sole Dairy Biomethane Pilot project operational by the end of 2022.

Q 44 Which parties commented on the DBPMA?

A 44 Cal Advocates addressed this account.

Q 45 What is Cal Advocates' position?

A 45 Cal Advocates recommends the Commission reduce PG&E's recoverable amount in the DBPMA by $0.256 million.[37] This amount is related to Materials Movement costs, which Cal Advocates states are not incremental.

Q 46 Do you agree with Cal Advocates' position?

A 46 No, PG&E does not support Cal Advocates' position on this issue. Please see Chapter 1, Part C of PG&E's rebuttal testimony for discussion regarding incrementality Materials Movement costs recorded to DBPMA.

Q 47 In closing, what does PG&E recommend?

A 47 PG&E recommends the Commission find reasonable PG&E's recorded capital expenditures of $3.02 million in the DBPMA in full.

E. Conclusion

Q 48 Does this conclude your rebuttal testimony?

A 48 Yes, it does. For the reasons discussed above, the Commission should approve PG&E's cost-recovery proposal as reasonable. These costs were for work that is critical to our ongoing efforts to enhance public safety and reliability. PG&E prudently implemented this work—and recorded the costs

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37 Cal Advocates-05, p. 14, lines 7-11.

to the associated memorandum or balancing accounts—in accordance with Commission direction. We appreciate the time and effort that Cal Advocates and EPUC/IS have taken to review our costs and provide recommendations. We respectfully submit that our responses to their testimony here should lead the Commission to adopt our proposed costs underlying our revenue request in this proceeding.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT A

RECOVERY OF IN-LINE INSPECTION MEMORANDUM ACCOUNT (ILIMA) COSTS

THIS ATTACHMENT HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT B

RECOVERY OF INTERNAL CORROSION DIRECT ASSESSMENT MEMORANDUM ACCOUNT (ICDAMA) COSTS

THIS ATTACHMENT HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT C

RECOVERY OF GAS STATUTES, REGULATIONS, AND RULES MEMORANDUM ACCOUNT (GSRRMA) COSTS

THIS ATTACHMENT HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT D

RECOVERY OF TRANSMISSION INTEGRITY MANAGEMENT PROGRAM (TIMP) MEMORANDUM ACCOUNT (TIMPMA) COSTS

THIS ATTACHMENT HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT E

RECOVERY OF MEASUREMENT AND CONTROL (M&C) STATION OVERPRESSURE PROTECTION MEMORANDUM ACCOUNT (MCOPPMA) COSTS

THIS ATTACHMENT HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT F

RECOVERY OF CRITICAL DOCUMENTS PROGRAM

MEMORANDUM ACCOUNT (CDPMA) COSTS

THIS ATTACHMENT HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT G

RECOVERY OF GAS STORAGE BALANCING ACCOUNT (GSBA) COSTS

THIS ATTACHMENT HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT H

RECOVERY OF LINE 407 MEMORANDUM ACCOUNT (L407MA) COSTS

THIS ATTACHMENT HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT I

RECOVERY OF DAIRY BIOMETHANE PILOTS MEMORANDUM ACCOUNT (DBPMA) COSTS

THIS ATTACHMENT HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT J

PG&E’S RESPONSE TO CALADVOCATES_008-Q005

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire and Gas Safety Costs
Application 23-06-008
Data Response

PG&E Data Request No.:	CalAdvocates_008-Q005		
PG&E File Name:	WildfireandGasSafetyCosts_DR_CalAdvocates_008-Q005		
Request Date:	October 11, 2023	Requester DR No.:	PubAdv-PGE-008-BFA
Date Sent:	October 25, 2023	Requesting Party:	Public Advocates Office
PG&E Witness:	Karli Maeda	Requester:	Brennen Gallagher

SUBJECT: CDAMA; GSRRMA; TIMPMA; MCOPPMA; CDPMA; L407MA; DBPMA; ACCUMA; DRPTMA; DERDDA; AB841MA

QUESTION 005

Referring to PG&E testimony page 2-AtchE-2, PG&E states, "Pilot operated regulator stations, when compared to other M&C station types, are subject to a higher likelihood of OP event than other station designs… PG&E's OP Elimination Program Long-Term Execution Plan outlines the program development and execution plan for this program. PG&E pursues the strategy of installing secondary OPP devices at the pilot operated regulator stations."

a. Please provide documentation describing M&C station types other than pilot operated regulator stations.

b. Please provide documentation clarifying whether the Commission has approved PG&E's OP Elimination Program Long-Term Execution Plan. Include page numbers and references.

c. Please provide a copy of the OP Elimination Program Long-Term Execution Plan.

ANSWER 005

Attachment WildfireandGasSafetyCosts_DR_CalAdvocates_008-Q005Atch01CONF to this response contains CONFIDENTIAL information described in the Declaration Supporting Confidential Designation dated October 25, 2023.

a. PG&E is providing the most recent version of document GP-1104 – Measurement and Control Asset Management Plan, April 27, 2023, rev 9a, in, "*WildfireandGasSafetyCosts_DR_CalAdvocates_008-Q005Atch01CONF.pdf*". It presents an overview of the various M&C stations in its system.

   PG&E is also providing as attachments a selection of Gas Design Standards (GDS):

   - "*WildfireandGasSafetyCosts_DR_CalAdvocates_008-Q005Atch02.pdf*"- PG&E Gas Design Standard H-14, Gas Regulator Stations – Spring-Loaded and Pilot-Operated Systems, June 21, 2023, rev. 4c

- “*WildfireandGasSafetyCosts _DR_CalAdvocates_008-Q005Atch03.pdf*”- PG&E Gas Design Standard H-10, High-Pressure Regulator-Type Stations and Farm Tap Regulator Sets, May 17, 2023, rev. 5
- “*WildfireandGasSafetyCosts _DR_CalAdvocates_008-Q005Atch04.pdf”*- PG&E Gas Design Standard H-19, Gas Regulator Stations – Control Valve Systems, September 21, 2022, rev. 3
- “*WildfireandGasSafetyCosts DR_CalAdvocates_008-Q005Atch05.pdf”*- PG&E Gas Design Standard H-15, Design Requirements for Company-Owned Gas Regulating Systems Serving Customers, 08/19/2020, rev. 3

b. PG&E has developed the OP Elimination Program Long-Team Execution Plan as an internal document. PG&E has not received a request for approval by the Commission, and neither has sought approval from the Commission.

c. Please see attachment “*WildfireandGasSafetyCosts_DR_CalAdvocates_008-Q005Atch01CONF.pdf*”. The OP Elimination Program Long-Team Execution Plan can be found in Appendix M.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT K

OVERPRESSURE ELIMINATION PROGRAM SUMMARY OF PROGRAM DEVELOPMENT AND LONG-TERM EXECUTION PLAN

M. Overpressure Elimination Program

Overpressure Elimination Program

Summary of Program Development and Long-Term Execution Plan

Prepared by:

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Prepared for: Pacific Gas & Electric

REV. 3 (July 2022)

Note: This document has not had a legal review by PG&E attorneys.

0.0 Document Revision Log

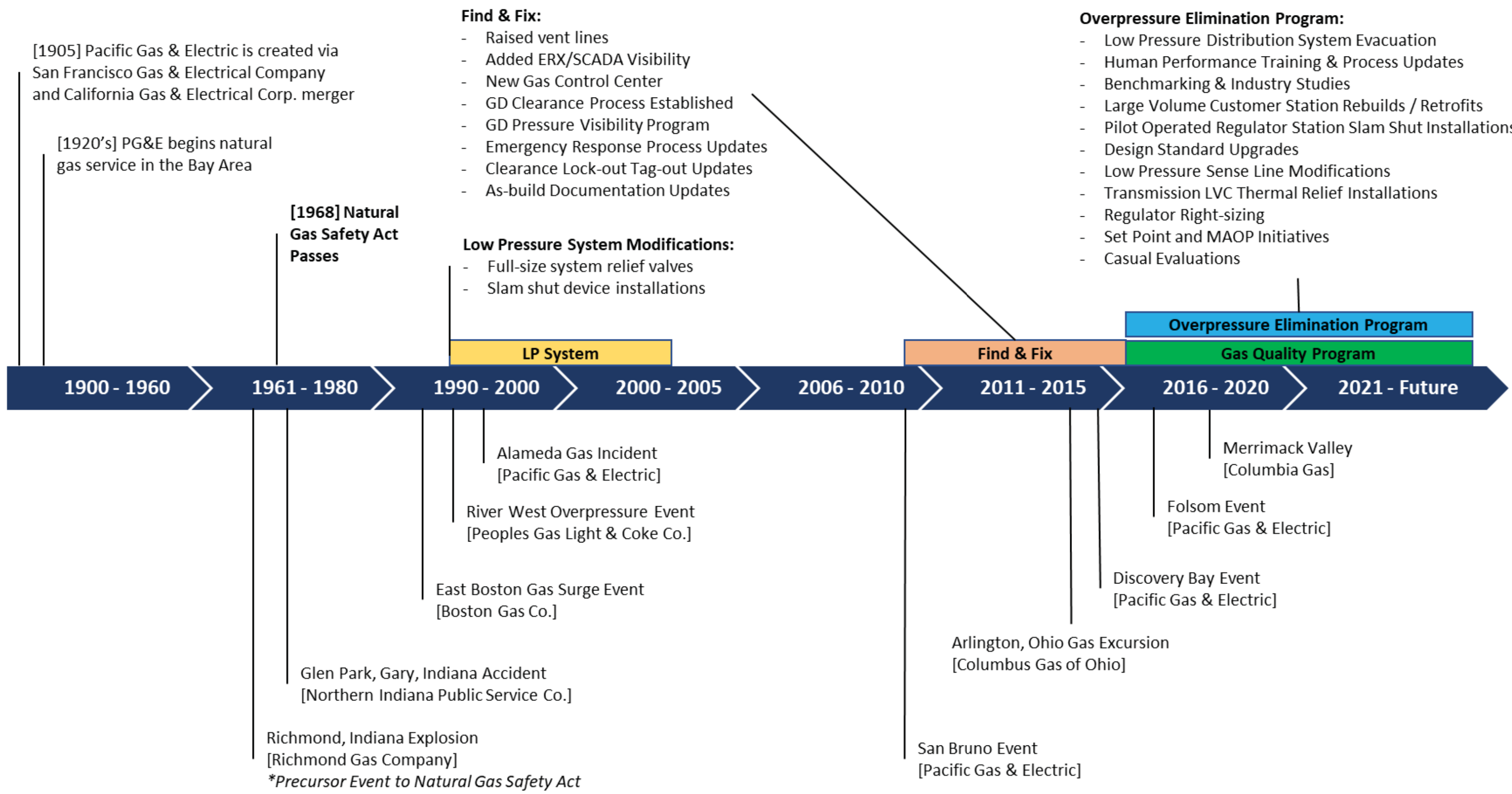
REVISION:	REVISION DATE:	REVISION DESCRIPTION
0	April 2019	Original Publication
1	July 2020	First Revision; Status Updates to Programs and Adjustments to Future Goals.
2	July 2021	Second Revision; Status Updates to Programs and Detailed Planning of Future Programs
3	July 2022	Third Revision; Status Updates to Programs, Detailed Planning of Future Program, and Priority Setting Methodology

1.0 Purpose

The purpose of this document is to chronicle the events and decisions that have influenced the company's current approach to overpressure (OP) protection at gas transmission and distribution district regulator facilities, while also providing a roadmap for future activities.

This document provides a summary of previously completed overpressure elimination initiatives, current OP initiatives, and what the current vision is surrounding activities supporting the Overpressure Elimination Program (OPE). In the current revision, additional program development and execution plans are detailed. By definition, the current view of future activities can change dramatically based on events, technology breakthroughs, and changes in regulatory statutes. As such, this is intended to be a living document that is likely to evolve over time. Figure 9 provides a timeline of key events and milestones that have shaped PG&E's current approach to Over Pressure Elimination.

Figure 9. Overpressure Elimination Event Timeline



2.0 Background

Pacific Gas & Electric (PG&E) was formed in 1905 with the merger of the San Francisco Gas & Electric Company and the California Gas & Electric Company. What began as a modest venture to light gas streetlamps in San Francisco has grown into one of the largest gas and electric utilities in North America. As the company grew it acquired competing companies to further increase our service area. We first began providing natural gas services to customers in 1930. From 1930 onward we continued to expand our gas transmission and distribution network through acquisition and direct investment. PG&E now serves approximately 16 million gas and electric customers from Bakersfield, CA to the Oregon border. The company continues to grow in size and sophistication while improving overall safety and reliability of distribution and transmission assets.

One of the challenges that our company faces is the continued maintenance and improvement of disparate legacy systems. In the early days of PG&E, cast iron was still the preferred material for pipelines. PG&E has successfully replaced all cast iron pipelines with high-grade steel and durable plastic pipes. However, as the service lives of these systems come to an end, there is an increasing likelihood of reliability issues or equipment failures. OP[36] events are the result of failures within the system. OP protection devices were first required in 1968 per the Natural Gas Safety Act of 1968. Even with primary protection devices installed, OP events continued to occur. PG&E relied on ASME standard B31.8S to influence the categorization of PG&E OP events. Per the standard, there are 22 root causes which are grouped into 9 failure type[37] categories that represent threats to pipeline integrity. We have determined that our OP events fall primarily into two of those categories: incorrect operation and equipment related. The incorrect operation category typically refers to OP events caused by human performance. OP events that are caused by equipment failures of any kind are characterized by equipment related failures.

Even with the improvements to material quality, new equipment, training, and procedures, there is still a risk of loss of containment due to over pressurization. As our company and industry evolves, new technology and equipment is required to deliver gas more safely and reliably to customers. Sometimes the technology triggers changes to operating philosophy and improvements are made in the course of normal operation and maintenance. Best practices also emerge that can further influence or change system design or operational philosophy. Tragic and devastating failures can lead to major leaps forward in safety, operability, and reliability. Historically, design emphasis was placed on keeping gas flowing as reliably as possible. As we've learned, however, that this desire has led to design that had unintended consequences of increasing the possibility of an OP event.

Companies, including PG&E, go to great lengths to design, construct, and maintain natural gas transmission and distribution systems to provide a reliable supply of natural gas to residential, commercial, and industrial customers. These systems utilize different equipment types and designs to prevent the likelihood of large and small OP events. As a result, the likelihood of an OP event is relatively small. In fact, large overpressure events are rare when modern regulation

[36] A large overpressure event is generally defined as an event resulting in a system pressure increase in excess of 110% of maximum allowable operating pressure (MAOP). Note this is general guideline. Please reference Appendix item 10.9 "Definition of Large OP Event and Other Associated Terms" for detailed definitions of overpressure events.
[37] "Managing System Integrity of Gas Pipelines: ASME Code for Pressure Piping, B31 Supplement to ASME B31.8", The American Society of Mechanical Engineers, 2018

equipment is operating within ideal operating tolerance, typically 10% to 80% range of its design capacity.

However, when a large OP event occurs, the consequences to the public can be devastating. In rare cases, death, injury, and significant property damage has occurred as a result of an OP event and its aftereffects. OP protection, which can be accomplished in several ways, is critical to preventing these events from occurring. The potential consequences of these types of events have served as catalysts for the development of PG&E's Gas Safety Excellence Program. PG&E's Overpressure Elimination Program is a key component of this program.

3.0 History and Impact of Significant Events and Findings

Past events have shaped the way that we, and the entire natural gas industry, evaluate and mitigate the risk of a loss of containment event. Examples of such events are as follows. Note that some of these industry-shaping events are not overpressure events but nonetheless have influenced the Overpressure Elimination Program development and decision-making process.

3.1 Richmond, Indiana Gas Line Explosion – Richmond Gas Corp.

On April 6, 1968, in downtown Richmond, a massive explosion occurred that decimated two city blocks. The blast and fires destroyed 15 buildings; damaged an additional 125; and 20 buildings were subsequently condemned. More than 150 people were injured, and another 41 individuals lost their lives in the explosion. After some investigation, it was determined that a cast-iron natural gas main had corroded so significantly that the line began leaking. When the gas ignited, it did so in the basement of the Marting Arms sporting goods store near a stockpile of ammunition and gunpowder. The location of the ignition undoubtedly compounded the effects of the explosion.

Initially, the Richmond Gas Corporation removed the corroded pipe from the scene and refused to allow investigators to examine the pipe. After an order from the Indiana Public Service Commission, the pipe was turned over to investigators who were then allowed to examine the pipe. The explosion resulted in the drafting of the Natural Gas Safety Act of 1968; the Act was passed just a few short weeks after the event.

3.2 Gary, Indiana Accident – Northern Indiana Public Service Co.

In early 1969, Glen Park's gas service was slated to be upgraded from ¼ PSIG to 20 PSIG. Recent and planned future development in the area had spurred the now necessary gas distribution system upgrade. The upgrade was to occur in two phases, where the eastern side of Glen Park would be upgraded to handle the new medium pressure and the western side would continue to use the ¼ PSIG low pressure system. The plan was to install a separation valve between east and west Glen Park, which would remain closed, to separate the disparate pressures. The two pressure regulating stations serving the Glen Park area were not equipped with over-pressure protection devices.

As NIPSCO was pressurizing the new 20 PSIG system, leaks were detected on an 8-inch main. The foreman ordered that the 4-in valve at the 47th & Harrison Street regulator station be closed to stop one of the sources of the 20 PSIG gas. Then, without instruction, a crew member opened the newly installed east-west separation valve sending the medium pressure gas into the low-pressure system. The team noticed the error quickly and closed the valve but not before allowing the medium pressure gas into the western Glen Park low pressure system. It was then that the crew discovered that the western sector regulator station was damaged and not properly reducing the gas pressure. The overload pressure was 80 times greater than the western area of Glen Park was designed to handle.

The overpressure resulted in fires and an explosion in western Glen Park. Seven homes were destroyed; 45 additional homes were also damaged to varying degrees. Had the regulator stations been designed to then-modern standards and equipped with the appropriate shut-off and redundancy equipment this incident could have been avoided.[38]

3.3 East Boston Gas Surge – Boston Gas Co.

On September 23rd, 1983, The Boston Gas Company received notification from the Boston Water and Sewer Commission that a water main had broken and was currently flooding a district regulation station located at the intersection of Bremen and Porter streets. The regulator valves in the vault had been submerged, and water had entered the regulator diaphragm via the vault vent piping and gasket leaks. The weight of the water in the regulator diaphragm forced the valve to remain open sending gas downstream to businesses and homes. As a result of the increased pressure, approximately 30 fires were started.[39] Fortunately, the Boston Fire Department was able to extinguish the fires quickly though one business was lost. The resulting investigation revealed that weights used to balance the monitoring regulator diaphragm were over-sized and physically blocked diaphragm movement. This event could have been avoided with a more robust maintenance plan and additional redundant fail-safe equipment.

3.4 River West OP Event – Peoples Gas Light & Coke Co.

On January 17th, 1992, following routine maintenance of a low-pressure regulator station, higher pressure gas exceeding 10 psig entered the low-pressure gas distribution system. The higher-pressure gas entered homes through appliances, where it was ignited, resulting in a number of explosions and fires. The OP event killed 4 people, injured 4, and damaged 17 structures.

The maintenance team was conducting routine maintenance on a regulator station. The company's standard operating procedure was to divert gas to a bypass line by opening and closing designated valves. However, it was during this process that the maintenance mechanic turned the wrong valve to the open position, instead of the closed position. The valve the mechanic was attempting to turn was impeded by minor debris. Once high-pressure gas had entered the low-pressure system, the mechanic failed to close the bypass valve. Had the mechanic been trained properly, the event and subsequent damage could have been mitigated. This is a classic example of how incorrect operations can lead to a catastrophic OP event.

[38] "Pipeline Accident Report Low-Pressure Natural Gas Distribution System", National Transportation Safety Board, June 3, 1969.
[39] "Safety Recommendation P-84-007", National Transportation Safety Board, April 9th, 1984.

3.5 Alameda Gas Incident – PG&E

The 1994 Alameda Gas Incident had a significant impact on the development and evolution of our operating and maintenance philosophy. This event occurred on a low-pressure system. By definition, gas is delivered to the customer at usage pressure; there is no final regulation of pressure at the customer gas meter. At the time of the event, the low-pressure system was designed to provide gas service to many customers through twelve (12) regulator stations. The design had proven effective and safe for many years. However, one of the stations failed causing high pressure gas to enter the low-pressure system and increased pressure in downstream homes and businesses. The resulting OP caused numerous fires and loss of gas service to many customers. The cause evaluation investigation revealed that we did not have adequate inspection documentation and that our emergency response planning was inadequate. The failure to properly capture the maintenance and inspection activities at the various stations made it difficult for field responders to identify and locate the malfunctioning station and to pinpoint the exact cause of the failure. Further, the delayed response time and lack of robust emergency response procedures likely lead to additional damage. Had a proper emergency plan been in place, and the decision to shut-in the system more quickly been made, the damage could have been mitigated.[40]

In many ways, the incident served as a catalyst for the company to review its maintenance and inspection procedures, emergency preparedness, and overall operational philosophy. As a direct result of the Alameda incident, we revised operational philosophy to prioritize preventing loss of containment over loss of service for low pressure systems. One of the actions resulting from the revision to the operational philosophy was to change the design approach for gas distribution systems. We increased the number of regulator valves and stages to reduce the pressure between high pressure systems and low-pressure systems. We also added more regulator stations to decrease the number of customers served by a single station. Ultimately, secondary OP protection devices (slam shuts) were installed to prevent another large OP event on low pressure systems. And finally, emergency response was completely overhauled and improved.

The Alameda event provided many lessons learned which ultimately changed the way our company approached the design and operation of their low-pressure systems. Perhaps the most significant change was to the operating philosophy with the revised philosophy prioritizing loss of containment over loss of supply. The steps taken in response to the Alameda event greatly reduced the likelihood of OP events in similar systems.

As much as the Alameda lessons learned improved safety and operability, OP events continued to occur throughout the system. In general, the events were small and caused little or no disruption. But the steps taken to improve after Alameda only addressed part of the OP risk potential in the system.

[40] "Alameda Gas Incident Investigation", California Public Utilities Commission Safety Division: Utilities Safety Branch, June 22, 1994

3.6 San Bruno – PG&E

On September 9th, 2010, a 30-inch-diameter PG&E pipeline ruptured in San Bruno, California. The rupture released an estimated 47.6 million standard cubic feet of natural gas that ignited and resulted in a fire that destroyed 38 homes and damaged 70 more. Eight people were killed, and more were injured[41]. The rupture was caused by a fracture originating from a bad weld on the line. The defective weld could no longer withstand the normal operating pressure of the pipeline, which ultimately led to the rupture. The investigation revealed that the section of pipe was not installed per the standards of the time (1956) and had not appropriately documented or addressed the potential risk of failure for this line.

Although this incident was not the result of an OP event, the San Bruno line rupture and fire clearly demonstrated that we needed to reevaluate the operation of the entire system. Soon after the San Bruno event, we began an evaluation of transmission and distribution systems to identify the delivery systems that had the highest risk potential from an OP standpoint. We identified pipeline integrity as a high-risk potential and implemented their Pipeline Safety Enhancement Program (PSEP) to review integrity documentation, identify gaps, and execute the program to test and evaluate the integrity of their transmission and distribution pipeline systems. The program focuses on the replacement or repair of these systems to significantly enhance pipeline integrity.

3.7 Arlington, Ohio – Columbia Gas of Ohio

On March 21st, 2015 a natural gas explosion occurred at a residential property resulting in a fire, significantly damaging the property. The resulting investigation revealed that the explosion was caused by the incorrect operation of a valve on an abandoned line located within a curb box. The line had previously been abandoned due to corrosion. The valve was misidentified by a Columbus Water Department employee while the employee was attempting to shut off water to the resident. The employee opened the valve, determined the water was not shut off, and then did not fully close the valve, allowing gas to bypass the valve. A few days later, a U.S. Postal Service employee noticed a strong smell of gas emanating from the residence. Columbia Gas dispatched a repair crew, and while the crew was in route to the residence the explosion occurred. The Public Utilities Commission of Ohio concluded that Columbia Gas failed to follow company installation and abandonment procedures, which indicated that abandoned lines, must be cut off at the main and all open ends plugged or sealed. Per procedure, the curb box would be filled with concrete or paving to prevent incorrect operation. In this case, the valve box was filled with gravel and the lid was replaced. Further, the company failed to properly document the line abandonment with a "Service Line Order" form[42].

[41] "Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010" National Transportation Safety Board, Accident Report NTSB/PAR-11/01 PB2011-916501
[42] "Natural Gas Pipeline Failure Investigation Report", The Public Utilities Commission of Ohio, July 24th, 2015.

3.8 Discovery Bay – PG&E

On December 27th, 2015, the Discovery Bay distribution system was isolated due to erratic pressure readings observed by the Gas Distribution Control Center. Operations personnel were sent to the site to diagnose and fix the issue. The operations personnel arrived on site and observed that the station was frosted over. To avoid a potential overpressure the decision was made to shut in the station until gas could be safely regulated. Further investigation revealed that the ambient conditions and the moisture content of the gas had resulted in ice hydrates impacting the proper operation of the station. As a result, customers downstream of the station temporarily lost gas service. To avoid future issues, a procedure was developed to handle high moisture readings, should they occur. Heater and filter dryers were also installed on pilot gas supply lines at the station. We worked diligently to restore service to customers and was able to restore gas service to all impacted customers in a matter of days.

3.9 Folsom – PG&E

On January 24th, 2017, the Hydraulically Independent System (HIS) that delivers gas to the Folsom area experienced a large OP event in excess of the system's 60 psig MAOP. Gas Pipeline Operations and Maintenance (GPOM) technicians were dispatched to the three district regulator stations that supply the Folsom HIS. The technicians inspected each station and determined that the East Bidwell & Oak pilot-operated regulating station was the source of the OP event. Inspection of the station revealed that the station filter had been clogged with debris and the regulator boot had been eroded by contaminants.[43] The overpressure event caused damage to the regulator station equipment and resulted in a significant number of leaks on plastic distribution piping. Nearby stations were inspected, and it was discovered that 11 additional stations with contaminated filters, damaged regulators, or debris in the station piping. Lab analysis concluded that the 'black powder' debris was a combination of organic particulates and corrosion scales. Further investigation revealed that an upstream pigging project in the area likely scraped corrosion scales from internal pipe walls. The scales, along with other debris, travelled downstream until eventually collected at Folsom and caused the OP event.

[43] "Gas Operations Root Cause Evaluation Report: Folsom HIS Overpressure Event," Pacific Gas & Electric, SAPN 7041620, January 2017.

3.10 Merrimack Valley – Columbia Gas

On September 13th, 2018 a contracted Columbia Gas crew was performing a tie-in of a new plastic distribution main and abandonment of a cast-iron distribution main. The old main still had the regulator sensing lines that were used to detect pressure and provide input to the regulators. Once the switch-over to the new main occurred, the sensing lines began to lose pressure. In response, the regulators opened to allow for greater flow resulting in OP downstream. The resulting OP caused explosions and fires damaging 131 structures, killing one person, and forcing approximately 30,000 people to evacuate.[44] Columbia Gas developed and approved the tie-in work package; however, the package did not account for the location of the sense lines.

The Merrimack event prompted PG&E to evaluate and reprioritize low pressure system risks associated with over-pressurization. Efforts include addressing new failure modes, reviewing NTSB recommendations, and a full system analysis.

3.11 Benchmarking Studies

In 2015, we commissioned Juran Benchmarking, Inc to perform a benchmarking study of European natural gas system operators. The study was undertaken to document information related to operational and lifecycle information on compression, regulations, and pipeline assets. One of the significant revelations of the Juran study was how few OP events were being reported by European operators. We subsequently asked another company, DNV GL, to conduct an analysis between PHMSA and European Union requirements regarding OP protection. DNV reported that a major difference in the regulations was a requirement of secondary OP protection under certain conditions. This addition of secondary OP protection is precisely the solution that we had previously implemented on all of their low-pressure systems as a result of the Alameda event.

The benchmarking studies and lessons learned from the research have been shared throughout the industry. We continue to collaborate with other operators and contribute to regulatory and industry publications. Our various subject matter experts have produced several presentations and articles to promote the need for overpressure event mitigation strategies. Our company has assisted the American Gas Association with the development of the AGA's "Leading Practices to Reduce the Possibility of a Natural Gas OP Event[45]" document to share current standards and procedures. Additionally, we have presented findings related to Overpressure Events at the

[44] "Preliminary Report Pipeline: Over-pressure of a Columbia Gas of Massachusetts Low-pressure Natural Gas Distribution System", National Transportation Safety Board, 10/11/2018
[45] A copy of the document can be found in the appendix of this report, item 10.08.

Western Gas Measurement Short Course (WGMSC) Conference and AGA, to further share strategies and lessons learned.

In December 2020, our subject matter experts participated in an informal AGA survey with other gas industry companies. Of the 31 companies surveyed, 22 currently employ some type of secondary overpressure protection device at their pressure regulation stations. Slam shut devices and relief valves are currently the most common mitigation employed by these companies.

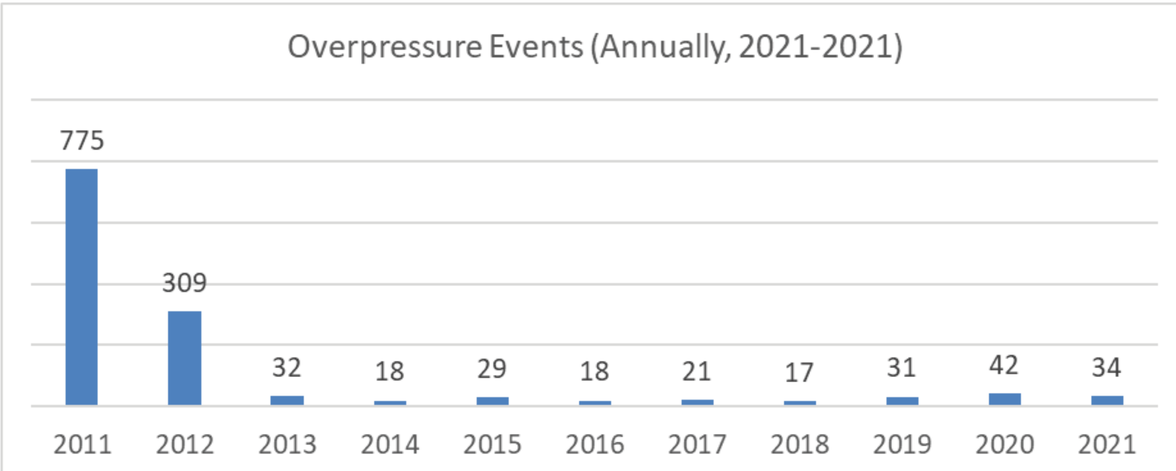
As part of our ongoing effort to share information with industry organizations and partners we have participated in additional informal AGA operator surveys. In 2021 we initiated an AGA survey to find out what operator's policies were in relation to regulator pressure set points in relation to maximum allowable operating pressure (MAOP). In short, the survey found that the majority of operators held regulator slam shut setpoints above MAOP and used seasonal setpoints. PG&E has developed a setpoint reduction program that will document the scope, benefits, risks and change management necessary to reduce the setpoint of secondary OOP devices below OPP. As of 2022, the team has analyzed historical overpressure events and found that a significant number of the events could have been avoided or mitigated. The setpoint reduction effort will focus on reducing setpoints when sufficient capacity is available so that an upgrade project will not be required. The initial phase of the program is focused on reducing setpoints at our pilot-operated high pressure distribution systems. No low pressure or transmission stations are currently in scope.

4.0 Overpressure Elimination Early Actions (Pre-OPE Program)

Following the San Bruno event in 2010 an OPE Task Force was established. The task force assembled subject matter experts throughout the organization to identify the root causes of overpressure events and develop corrective actions. One of the first steps was to collect large and small OP event statistics. In 2011, 775 OP events were identified, 21 of which were classified as large OP events. Several of the decisions and steps made in response to the San Bruno incident greatly reduced the number of OP events.

Below is a chart summarizing the OP data:

Chart 1: Total Overpressure Events (Annually, 2011-2021)



As a result, operating parameters were modified to lower the normal operating pressure below the maximum allowable operating pressure (MAOP). Prior to San Bruno, low pressure distribution systems typically operated at or near the maximum allowable operating pressure which prevented the system from absorbing normal fluctuations in system pressure. These normal fluctuations would register as OP events. The OP Task Force conducted a transmission and distribution system evaluation in preparation of a system-wide reduction in set point pressures. As a result of this change the system operated at a lower, safer pressure, and was able to absorb modest fluctuations without over pressuring the system. This change resulted in a significant drop-off of OP events from 2011 to 2012. As of 2022, the OPE team is evaluating further reduction of system and equipment set points. The analysis is ongoing, but one potential outcome could be a set point reduction for certain asset types and/or specific stations. PG&E solicited feedback via the AGA member survey process to collect information on other operators' actions and philosophies regarding set points.

Beginning in 2013, casual evaluations were conducted on all OP events, large and small. Where possible we developed corrective actions to prevent future events at identified OP event locations. Some of those corrective actions included, but were not limited to, equipment and design review, training, fatigue management, improved Gas Event Reporting, and improved work procedures. In May of 2019 the standard requiring casual evaluations on all OP events was revised. The revision eliminated the requirement for casual evaluations on small OP events. However, causal evaluations for any OP event can be conducted at a Sponsor's request. We continue to perform causal evaluations on significant or unique OP events.

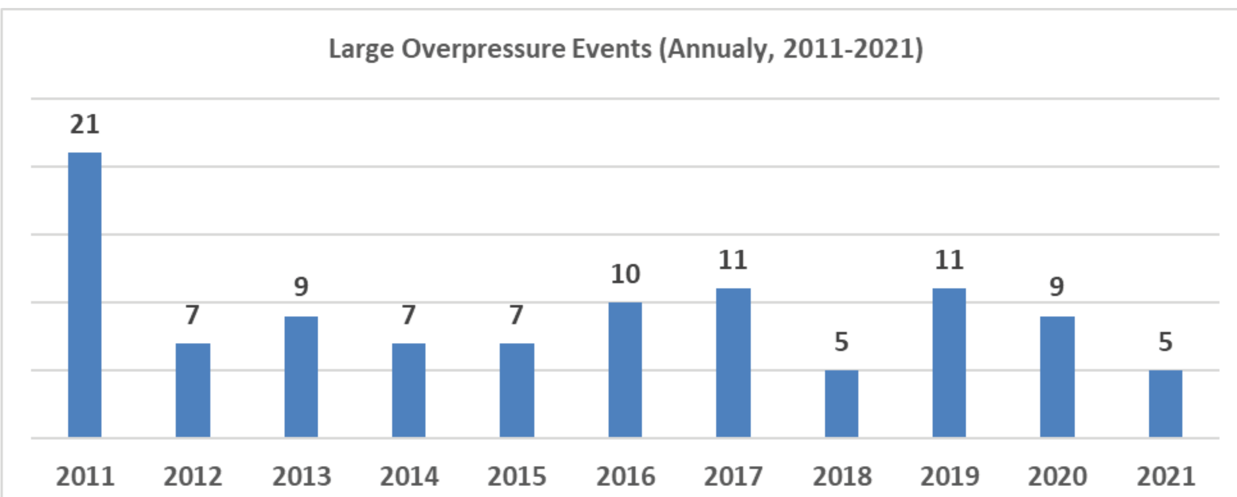
The following year (2014), vent lines were raised for low pressure regulator valves located in below ground vaults. Regulator valves use atmospheric reference along with spring tension to set regulator outlet pressures. But, when the vaults fill with rain or ground water, the vent lines can become submerged and add loading pressure to the regulator valve. The pressure change impedes the regulator valves' ability to control pressure at its set point and can result in an OP event. This change significantly reduced the number of OP events on low-pressure systems by eliminating this risk condition associated with the vent lines.

In conjunction with the steps described above, pressure monitoring devices were added throughout the system (SCADA & ERX). The pressure monitoring devices allow Gas Control to receive early warning of an OP condition. The early notice of a potential issue allows the maintenance crews more response time to resolve the issue before an OP event occurs.

We developed initiatives to improve the quality of station information. Field teams were put together to visit each transmission regulation station[46] to perform a condition assessment. Part of the condition assessment was to update and verify station documentation and maintenance records. Stations are visited on a regular maintenance cycle, but the condition assessment was performed to identify potential risks in the system. This allowed us to target potential troublesome stations for evaluation before an OP event occurred.

By the end of 2014, we had significantly reduced the occurrence of small OP events. The changes to operating philosophy, raising of vault vent lines, and installation of pressure monitoring equipment effectively reduced OP events. Although the population of small OP events drastically decreased, the causes of large OP events still needed to be addressed. The positive finding was that small OP events are not always precursors to large OP events for equipment-related events. These large OP events represent the greatest danger to the public. Due to the risk related to large OP events, and as a direct result of the Folsom event described earlier, the Overpressure Elimination program was implemented.

Chart 2: Total Large Overpressure Events (Annually, 2011-2021)

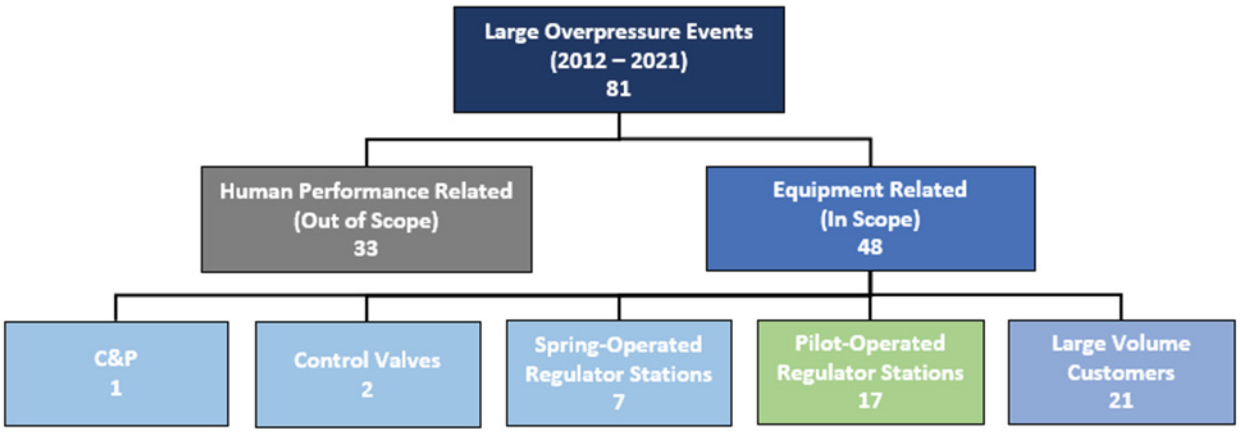


Between 2012 and 2020, 76 large OP events were identified within the transmission and distribution systems. PG&E contracted with Exponent, an internationally-recognized failure analysis and engineering consulting firm, to perform a cause identification analysis of our large OP events. Our own internal findings required validation before development of a strategy to confront common sources of OP events could begin. Exponent reviewed and analyzed the OP event data available through the end of 2020 and determined 46 of the 76 large OP events were due to equipment failure. The events were then categorized by facility type; this breakdown is illustrated in Figure 10. Exponent's conclusions and additional detail can be found in the white paper titled, "Secondary Overpressure Protection Strategies"[47]. The primary conclusion was the

[46] The condition assessments did not include Large Volume Customers as these were classified as distribution assets at the time.
[47] "White Paper: Secondary Overpressure Protection Strategies Distribution Stations", Exponent, September 2018.

majority of large OP events were equipment-related and impacted all pressure regulation station types. The remaining 30 OP events were due to Human Performance, which are addressed as a separate program in conjunction with but outside the scope of this roadmap[48].

Figure 10. Large Overpressure Events by Station Type & Cause[49]



As a result of the engineering analysis, we were able to pinpoint the common causes and sources of OP events in the system. We opted to prioritize pilot-operated regulator stations over other asset types. The analysis revealed that pilot-operated regulator stations had the common failure mode risk and had a high incidence of overpressure events when compared to other asset types. Additionally, the proposed mitigations to these stations would yield the greatest risk reduction benefit over the shortest amount of time due to the relative ease of installation and cost-effectiveness of slam shut devices. This approach required the development of a comprehensive strategy address these issues, not only for pilot-operated regulator stations, but for all asset types. In order to develop a strategy, we began researching industry best practices and commissioning benchmarking studies.

4.1 RAMP & Benchmarking

RAMP[50] (formerly Session D) is the current iteration of the legacy process that was established shortly after the San Bruno event to capture and evaluate catastrophic risk scenarios. It is based on the ASME B31.8S threat categories and is designed to identify and subsequently mitigate low probability, high consequence events. The risk associated with a large overpressure event was quickly identified as one of the highest consequence risks in the gas operations risk portfolio.

In an effort to determine the strategic approach to OP protection programs, we contracted a 3rd party consultant to conduct an international and North American industry evaluation to learn OP elimination best practices. Southwest Research Institute (SWRI)[51] performed a benchmarking

[48] Gas Planning & Maintenance is in the process of developing a Human Performance Roadmap. The expected initial publish date is June 2021
[49] Human performance issues will be addressed outside of the equipment-related mitigation program.
[50] "RAMP" is a PG&E acronym that stands for "Risk Assessment Mitigation Phase" and is a probabilistic model developed in conjunction with the California Public Utilities Commission to determine risk spend efficiencies for risk mitigation projects.
[51] "PG&E Natural Gas Industry Overpressure Protection Benchmarking Study", Southwest Research Institute Report No. 18032.17.01; June 29, 2017.

study of North America operators, and Juran Global[52] performed an international benchmark study, as described earlier. Additionally, DNV GL[53] prepared an industry analysis that compared European OP protection requirements to the Pipeline Hazardous Materials Safety Association (PHMSA) requirements.

The benchmarking studies and analyses helped influence the development and strategies of the Overpressure Elimination Program. The benchmarking studies indicated that our company was a top quartile performer among North American operators who responded with respect to the number of OP events per number of regulation stations. The key finding of the Juran report was that European operators experienced large OP events at a significantly reduced rate primarily due to the code mandated installation of secondary OP protection devices. After reviewing the conclusions of the benchmarking studies, we began developing a program to implement this industry best practice to reduce the company's risk of large OP events.

By 2017, we had determined the causes of recent large OP events, conducted international benchmarking studies, and reviewed industry analysis reports to influence future operational and maintenance philosophy.

PG&E continues to share OP lessons learned throughout the industry. In 2018 NiSource, a natural gas utility company serving approximately 3.5 million customers in 7 states, reached out to PG&E to discuss OP protection best practices. We were able to share the lessons learned and a description of the planned approach to eliminate large OP events. Through those knowledge sharing efforts, we have become an industry leader and influencer in OP protection. The lessons learned through the OP Elimination Program have been shared throughout the industry via fact-finding conference calls, industry events and presentations. As the program continues to evolve and develop, we are committed to providing information to other industry partners.

4.2 PG&E Design, Maintenance, and Operations Philosophy Changes

In early 2017, shortly after the Folsom OP event, PG&E senior leadership designated that a single group would be responsible for developing and implementing the strategy regarding the elimination of large overpressure events - the Overpressure Elimination Team. The stated goal of this program is to plan and execute initiatives and projects in order to drive the number of large over-pressure events to near-zero.

One of the first actions that the team took was to use the lessons learned from the benchmarking studies and the third-party consultant report to determine if any operational philosophy changes were needed. At the time, the company philosophy was to prioritize continuous service and avoid service interruptions. The team concluded that in order to operate more safely and reduce risk, PG&E would need to change its philosophy to prevent OPs and loss of containment, even if it meant loss of gas service to customers. The revised philosophy essentially transferred the risk profile from "loss of containment" (OP Risk) to the preferable and generally safer option of "loss of service" (LOS Risk). An example of this change in thinking is shown in Figure 3.

[52] "An Overview of Gas Transmission Asset Management Practices for Pacific Gas and Electrical Company", Juran Global, October 27, 2016.
[53] "Threat Management: Preventing Loss of Containment Due to Overpressure Protection", DNV Report No. OGNL.126867; April 11, 2017.

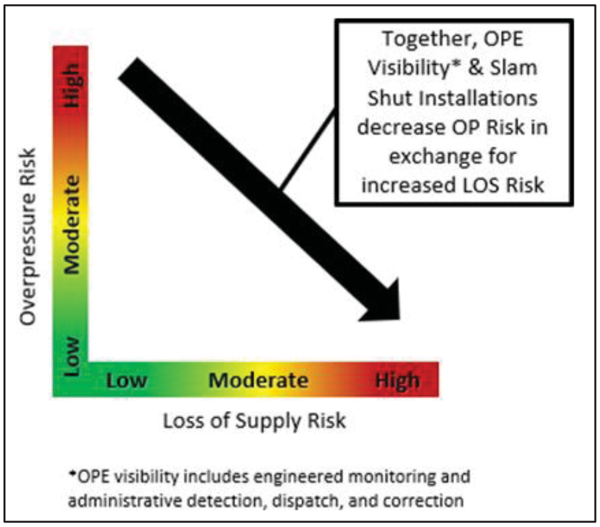
The low-pressure systems were identified as high risk due to the potential to OP very large distribution networks feeding many customers with a relatively small (<1 PSIG) amount of pressure. Unlike semi or high-pressure distribution systems, low pressure systems do not have a regulator as part of the house meter set to serve as a final barrier to overpressure events. As a result of the Alameda incident described earlier, the pressure regulator stations upstream of these low-pressure distribution networks were retrofitted with slam-shut devices to interrupt service to prevent an OP event. In 2011-12, system operating pressures were lowered as low as was practical to meet system demand. Supervisory Control and Data Acquisition (SCADA) capabilities were also added to provide visibility and alert Gas Control when pressure ranges were being exceeded. Additionally, any existing regulator stations installed within a vault below grade or street level had their vent lines modified to end at an above grade location to prevent them from being plugged as the result of a flooded vault. MAOP of utilization pressures were increased to align with GO58 section 8[54].

Spring-operated regulator facilities (generally referred to as Farm Taps) also have OP risk, albeit low risk. These regulator facilities are used to supply gas to a single or very low (<3) number of users. Since the stations feed so few customers, they are often subject to very low flow or no flow conditions. Failure of the upstream regulating station could over pressurize the system and cause significant damage to these end users. Inspections of the spring-operated facilities revealed that these assets were subject to the common failure mode risk. As a result, we implemented a program to remove or upgrade the farm taps within the system. We also implemented a significantly more robust maintenance program to regularly inspect and refurbish these facilities. This maintenance program was a result of the new code section implemented in 2017, §49 CFR 192.740.[55]

[54] GO58 Section 8 prescribes standard gas delivery pressure requirements for Gas Utility companies. A) Each gas utility must establish, adopt and maintain a gas pressure delivery standard; b) Pressure at customer meter shall be between 2 and 12 inches of water column.; c) summaries tariff filing requirements with the Commission; d) Requires Commission approval of proposal pressure delivery standards; e) Gas utilities may meet higher pressure requires for large volume or high pressure customers; f) Sets boundaries for gas pressure fluctuation, e.g. pressure shall not vary +/- 50% above or below standard pressure standard levels. Complete General Order is included as Appendix item 10.11.

[55] § 49 CFR 192.740: Pressure regulating, limiting, and overpressure protection – Individual service lines directly connect to production, gathering, or transmission lines. PHMSA now requires that, “each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and test at least once every 3 calendar years…”

Figure 11. Change in Risk Profile of Pilot-Operated Equipment with the Addition of a Slam Shut Device



Now that the company had settled on the new philosophy, we needed to review the existing station standard design and equipment options that would help implement this newly adopted plan. The Exponent report presented six equipment options to PG&E for consideration for pilot-operated regulation equipment. Each equipment-related option was considered as a possible mitigation to be added to existing distribution and transmission regulator stations to mitigate the risk of large OP events. The equipment options included:

1. Slam shut devices
2. Additional regulation on single run stations
3. Additional working monitor
4. Station relief valves
5. System relief valves
6. SCADA control and visibility

The Exponent report concluded that pilot-operated regulator stations were the most susceptible to OP from the various threats to the system (debris, liquids, etc.). Additionally, it concluded Large Volume Customers (LVC)[56] represented an over pressure risk that should be elevated in priority to mitigate. LVCs are typically supplied by pilot-operated equipment also, and often contain the additional risk of low to no flow.

With the equipment options and station types identified the strategy and solution began to take shape. Pilot-projects were developed for each of the potential equipment solutions. After laboratory testing, equipment was installed at various stations. The performance of each station with pilot equipment was monitored and evaluated. Not only did the stations perform well with the new equipment, but the installations were also simple and cost effective. This combination of benefits made for an ideal strategic solution for minimizing OP risk.

[56] Large volume customers are typically characterized by high volume, intermittent flow, and high-pressure service. Examples include refineries, industrial application, manufacturers, and food processors. LVC's are defined in Utility Procedure TD-4125P-10, Attachment 1 as "gas facilities which have the capability of delivering 40,000 standard cubic feet per hour (scfh) or more."

For the pilot-operated regulator stations, it was determined that the most effective solution to prevent OP events from occurring included the following steps:

- Installation of slam shut devices on the monitoring regulators.
- Installation of filtering equipment on the regulator pilot sensing lines.
- Installation of pressure monitoring and transmitting instruments to provide visibility of theprocess conditions at the Gas Control Center.

Following the 2018 Merrimack event, the PIPES Act of 2020 was signed into law. The PIPES Act requires operators that employ "primary-to-monitor" common failure mode station design to install secondary overpressure protection devices, or alternatively, eliminate common failure modes in station design. Common failure mode refers to the default failure modes of pressure regulating equipment in station design. For example, on distribution regulator stations the design may be such that both the primary regulation device and monitoring regulator device are designed to fail in the 'open' position. The new regulations seek to mitigate the risk of this design through the installation of overpressure devices or revised station design. Slam shut installations essentially modify a station from an 'open-open' failure mode to a 'open-close' failure mode (non-common failure mode).

In the following sections, there are brief descriptions of the various OP protection devices and activities:

4.2.1 Slam Shut Devices

A slam-shut device works by physically closing a regulator valve to prevent any gas from passing through the valve. The device is mechanical and reacts automatically based on pressure set points determined by gas operations. Once the system pressure reaches the set point, the slam shut engages. Slam shut devices address the common failure mode[57] issue by physically closing the valves and preventing gas from flowing. They are reliable, widely used in the industry, and are relatively straight forward to retrofit to existing regulator valves when compared with other options. PG&E has approved the use of slam shut devices on 2″, 3″, and 4″ Mooney regulator valves as of 2022.

4″ Slam Shut Regulator

4.2.2 Filtering Equipment

The addition of sulfur filtering equipment on the pilot sensing lines can help mitigate some of the gas quality issues (debris, liquids, etc.) that cause OP events. Filters installed on the sense lines can remove liquids, sulfur, black powder, and other debris. Clear sense lines will ensure that the pilot-operated regulator valve is receiving the correct pressure from the system and allow the valve to properly regulate gas pressure.

Unfortunately, PG&E has worked with two separate vendors and has encountered manufacturing and operational issues with both types of sulfur filters. The team is engaged with vendors to develop the appropriate filter element configuration that will work as planned in the system. The new filter cartridges are being tested and their efficacy validated by the test lab

[57] Common failure mode typically refers to devices that fail in the same fashion. For example, in regulator station design, a monitor and regular may both fail in the "open" position, allowing gas to continue to flow.

prior to resumption of system wide installation. The installation of sulfur filters is therefore currently on hiatus and the program is not expected to resume prior to 2023 at the earliest.

4.2.3 Pressure Monitoring and Transmitting Devices

Although the company has changed its operating philosophy to allow for a system shut-in, it needs to be stated that this is a highly undesirable event. In order to prevent slam shuts from engaging and communicate with a slam shut does engage, devices that monitor and transmit pressure data to the PG&E control room have been installed. These devices provide early warning of an OP condition by measuring the pressure between the regulator valve and monitor valve. A significant pressure change in the system sends an alarm to the control room. If the slam shut were to engage on one valve of a dual run configuration, Gas Control receives a slam shut engagement signal. Gas would continue to flow through the other run. Multiple alarms will occur prior to shut-in of the station allowing Gas Control to dispatch a technician to troubleshoot the cause of the alarms. Based on this information, it is likely that the control room can dispatch a maintenance crew to investigate and correct the problem before loss of supply to the downstream system. This means for the slam shut to activate, the regulator and monitor both must fail to control pressure.

Example of ERX Pressure Monitor

4.2.4 OPE Program Decision Trees

Part of the strategy for the program was to determine the correct priority for station slam shut and pressure monitoring device installations. Some stations can be shut-in with no impact to customers. Typically, those stations are part of a larger network and other stations in the system will continue providing gas. There are a small number of stations that are too critical to be shut in. These stations either serve a large volume customer like a refinery, hospital, or serve such a large customer population that if gas service were interrupted customers could be without gas service for many days.

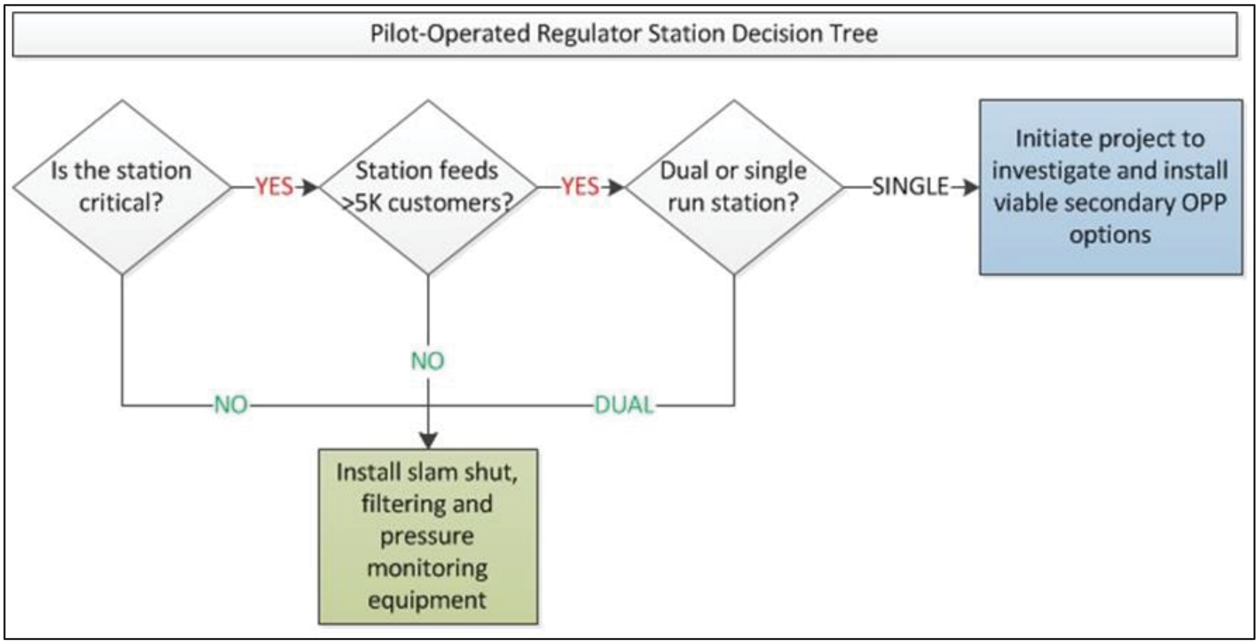
A decision tree was developed to assist with narrowing the population of critical stations and prioritizing non-critical stations. The purpose of the decision tree is to help identify stations where installation of slam shut devices is the appropriate solution while also noting which stations are critical (i.e., always in use) and may require custom OP protection solutions.

In general, a station is marked for further review and investigation if Gas Planning determines that the station is too critical[58] to be shut-in or is a single-run configuration that serves more than 5,000 customers. After further review and investigation, Facility Integrity Management may conclude that a slam shut device is still an appropriate solution. They may also conclude that a different approach is needed because a station shutdown could have an adverse impact. If this is the case, it would trigger a stand-alone project to come up with an appropriate and resilient solution (i.e., redundancy, relief valves, different regulator types, etc.).

The decision tree for distribution pilot-operated regulator stations and large volume customers is shown in Figure 12. A complementary decision tree will be developed for transmission assets.

[58] Critical stations are defined as stations that are needed under all operating conditions or serve high-impact customer types (e.g., refineries).

Figure 12. Critical Station Decision Trees for Pilot-Operated Regulator Stations

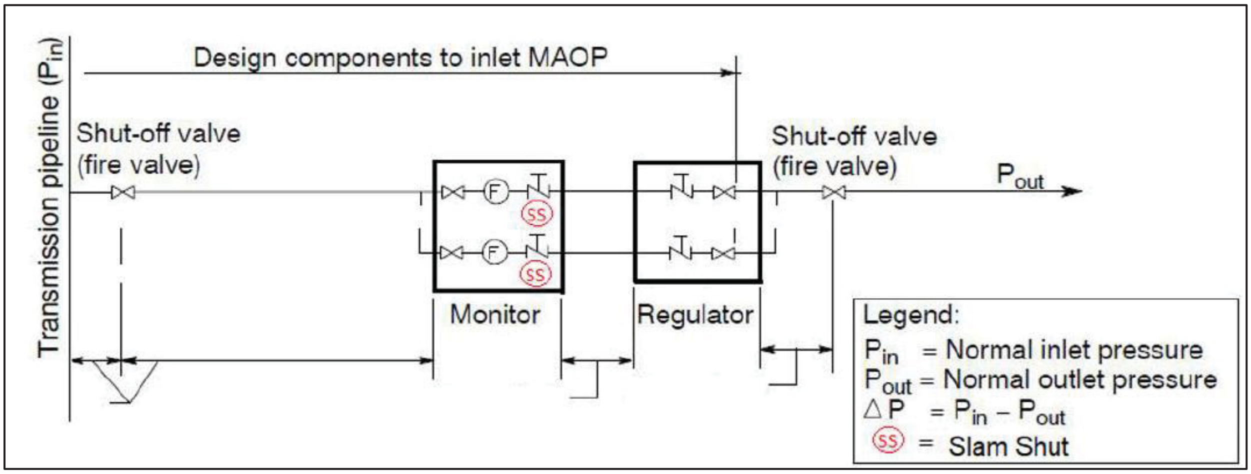


5.0 Pilot-Operated Regulator Station Overview

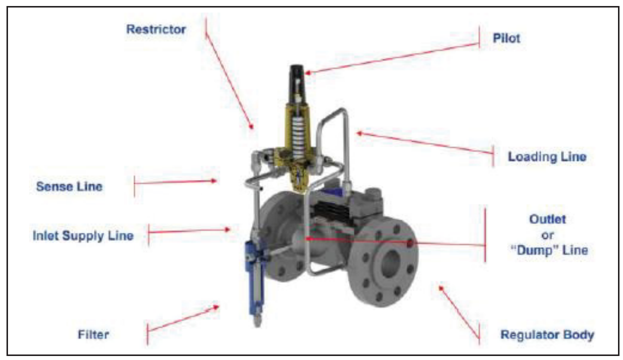
The purpose of this section is to provide additional context and overview of a typical regulator station. The schematic illustrated in Figure 13 is representative of a station prior to the modifications required forthe OPE Program.

The typical design of a pilot-operated regulator station calls for two parallel regulator runs, each with its own filter, pressure monitor, regulator valve and monitor valve. The regulator valve is the primary regulating device at the station. If the regulator fails, the monitor regulator will take over and begin regulating pressure. The regulator and monitor valves control the gas pressure sense lines. These small diameter tubes transfer the pressure of the pipeline to the pilot which loads and unloads pressure onto regulator and monitor valve diaphragms. Depending on the pressure, the diaphragms open or close to control the pressure.

Figure 13. Pilot-operated Regulator Station Exhibit



Regulator stations can malfunction for a variety of reasons, incorrect operation of the station valves, poor condition, equipment failure, or debris in the system. Sense lines can become blocked by debris in the system causing the primary regulator valve and working monitor to fail. Debris can erode the soft components of the regulating valves and prevent them from regulating gas pressure correctly. If the soft goods are worn down enough, this can prevent the valves from fully opening or closing properly and may result in an OP event. Pressure monitoring devices let the operators know where the pressure changes are occurring in the system and help operators recognize a potential problem with a regulator.



Cross-section of regulator valve

Since the pilot operated regulator stations are arranged with two similarly configured regulating valves in series (one to control and one to take over if the control valve fails), both the regulator and monitor valves can fail when subject to poor gas quality conditions. The equipment failures sometimes result in OP events because the pilot-operated regulation equipment normally fails in an "open" mode, allowing gas to freely pass through the valve. With both valves failing open, the risk of an OP event is high because the downstream system is not typically designed to handle the higher pressures.

6.0 Summary of Activities Performed to Date

PG&E has committed significant time and resources to address the risk of OP events and develop successful prevention strategies. 775 small and large OP events were recorded in 2011, and by the end of 2021 the total number of small and large OP events was 34. Only 1 of the 5 large OP events was attributed to equipment failure in 2021. Also, in 2021, we had 16 slam shut activations – that is, the slam shut devices engaged due to high pressure. Had we not implemented such an aggressive program to mitigate common failure mode OP events with the installation of slam shut devices, a portion of the 16 slam shut activations could have caused additional large OP events and risk to the public and our employees.

6.1. Completed Pilot-Operated Regulator Stations (Transmission & Distribution)

- **Pressure Regulation Standard Review & Revision [2019]:**
  The OPE team investigated the best practices for pilot-operated regulator station design to eliminate OP risk. As a result, design standard (H-14) has been updated to incorporate industry best practices (alternate placement of the slam shut) and represents a significant shift in PG&E operating philosophy.

- **Condition Assessment of Existing Transmission Regulator Stations [2012-13]:**
  Conducted a physical review of assets at each station to document current station condition and design configuration. After the physical review was completed, each station's configuration was compared against known best practices. The comparisons were used to help plan station modifications.

- **Slam Shut Device Installation (pilot projects) [2017-18]:**
  19 slam shut devices were installed at various stations throughout the system. The purpose of the pilot project was to validate the reliability of the slam shut devices as well as determine what impact, if any, the devices would have on system hydraulics. The slam shut devices operated as planned, with no discernable impact. The success of the pilot project influenced the overall program direction of installing slam shut devices throughout PG&E's system for pilot operated stations.

- **Test Alternate Equipment / Manufacturers (pilot projects) [2017-18]:**
  Many alternative regulating equipment types exist in the industry. PG&E primarily uses Mooney regulators at their pilot-operated stations. The purpose of this series of pilot projects was to determine if alternative regulator types might be better suited to eliminate OP risk throughout the system. Approval of the use of the Pietro Florentini regulators at higher flow / higher pressure pilot-operated stations is an example of the effective use of this process. This process will continue to be utilized as new equipment comes on the market.

- **Secondary OP Protection Feasibility Study (Transmission & Distribution) [2018]:**
  The OPE team prepared a feasibility study to evaluate secondary OP devices and other approaches to define acceptable methods of mitigating large OP events for hydraulically independent systems served by regulator stations.

- **Pilot-Operated Regulator Station Pilot Program (Distribution & Transmission) [2017-18]:**
  This program included the complete engineering, design, and construction for single feed and dual feed regulator stations. The goal of the program was to evaluate the approach, cost, and schedule of building or modifying stations with new equipment. The results from these pilot installations influenced the program estimates and proposed schedule.

6.2 Completed Large Volume Customer Programs

- **Inventory Existing Transmission Meter Set Assemblies (MSA) [2016]:**
  Conducted a physical review of assets at each station to document current station condition and design configuration. After the physical review was completed, each station configuration was compared against known best practices. The comparisons were used to help plan station modifications.

6.3 Completed Large Volume Customer – Primary Regulator Sets Programs (LVCRs, Transmission)

- **LVCR Pilot Program [2018]:**
  Perform a feasibility study to determine necessary modifications to the primary regulator sets upstream of a large volume customer. Develop a modification plan and execute the pilot project. The purpose of the project is to evaluate the approach and cost of the proposed modifications.

- **LVCR Feasibility Study / Design Standard Development [2018]:**
  The purpose of this study was to leverage known best practices to develop a new LVCR design standard. The new design conforms to PG&E's pilot-operated design standard.

- **Inventory Existing LVCRs [2017]:**
  Conducted a physical review of assets at each station to document current station condition and design configuration. After the physical review was completed, the stations' current configuration was compared against the new design standard. The comparisons were used to help plan station modifications.

- **LVCR Prioritization [2017]:**
  Developed a priority list of LVCR stations.

- **Accelerated "B" Inspections on LVCRs [2017]:**
  PG&E conducts regular inspections of regulator stations on a yearly cycle ("A" inspection) and rebuilds the regulators on an 8-year interval ("B" inspection). The "B" inspections require maintenance to inspect stations, note their current condition, and replace the soft goods.

  Unfortunately, LVCRs were previously classified as Farm Taps and therefore only received 3-year atmospheric corrosion inspections, even though the station contained pilot-operated equipment. Once this became known, PG&E accelerated the timeline for these inspections to better understand current station condition of the LVCRs. All of the accelerated inspections were completed in 2017.

6.4 Completed Control Valve Transmission Regulator Stations Programs

- **Pressure Regulation Standard Review [2016]:**
  The review of this design standard, H-19, has been completed and implemented.

6.5 Completed OPE Management Programs

- **Update Procedure for Post-Hydrotest Line Drying [2021]:**
  Procedure TD-4137P-03 has been updated to require drying after all hydrotests.

- **Benchmarking Studies [2016-17]:**
  PG&E has completed the benchmarking studies to determine where the company ranks in relation to other operators with regard to best overpressure elimination practices. PG&E has continued to participate in AGA surveys and conferences to share knowledge and stay abreast of latest industry trends.

- **Borescope Inspection Procedure [2018]:**
  After a station has been modified, an inspection is required to ensure that the station is clean, and no debris or liquid is left behind after construction activities. The borescope inspection is conducted after construction or modifications have been completed at new, rebuilt, or existing stations that have received major modifications. The procedure (TD-4546P-01) for this type of inspection has been updated and is complete. A process to determine potential debris at legacy stations is currently being reviewed for development.

- **OPE Communication Plan [2018]:**
  The OPE team developed and implemented an organization communication plan. The purpose of the plan was to inform and gather feedback from stakeholders throughout the organization, as well as provide current status of OPE program activities. The original plan was completed in 2018; presentation to various stakeholders now take places on an as-needed or as-requested basis.

- **On-going OP Communications [On-going]:**
  In addition to this long-term planning report, the OP regularly gathers and distributes communications to the various PG&E stakeholders. Information about the program is distributed monthly, accompanied by recent performance metrics. Additional information is available on team SharePoint and Microsoft Teams sites. This on-going communication has assisted with bringing awareness to OP and helped prioritize the effort.

- **In-Line Inspection Operation Debris Mitigation Study [2017]:**
  The goal of this causal evaluation is to evaluate procedural improvements to reduce the risk of debris entering the system subsequent to in-line inspection (pigging) operations. The causal evaluation has been completed and multiple corrective actions are in progress (CAP#: 7041620).

- **Monthly Steering Committee Meetings [2018 – On-going]**
  In 2018 a series of monthly meetings were established between various Gas Operations stakeholders. This is a Director-level meeting to ensure that the goals, priorities, plans, activities, and achievements of the OPE program are communicated and supported throughout the organization. Priorities are reviewed and discussed during each meeting.

- **Creation of an Overpressure Elimination Intranet Page and a MS Teams page [2020-21]**
  The Intranet page was developed to give all PG&E employees access to facts and figures regarding the Overpressure Elimination program. The page can be found here:

Overpressure Elimination Program. The MS Teams page was created to provide Senior Leadership and Directors information regarding the progress of the program.

- **Management of Change Procedure [2021]**
  The management of change procedure is crucial to the effective implementation of any changes to the system. Through the process, operations and maintenance groups are information of any changes planned. This communication allows for the safe operation of the system as conditions may change due to added or removed equipment. Formally notifying the impacted teams ensure the systems changes and implemented and operated safely. The OP team conducted an analysis of the MOC process to determine if any gaps were present. The process was updated and is now complete.

- **Set Point Database Improvements [2021]**
  The intent of this effort was to provide Gas Planning with a comprehensive accounting of all the pressure set points throughout the system. Originally, GPOM was to record set points 'as-found' and 'as-left' during maintenance activities. Those 'as-found' and 'as-left' points would then be added to a database. However, after further consideration, the team determined that the effort would be low value and high cost. As such, this effort was placed on indefinite hold.

- **In-Line Inspection Liquid Cleaning [2021]**
  In-line inspection and liquid cleaning activities have been found to increase OP risk. The liquids used in cleaning operations are not always fully recovered and the movements can move debris within the system. In order to mitigate the risk associated with liquid cleaning, the OP team worked with the ILI team to develop a planning and risk assessment procedure for ILI projects. The ILI team created new planning guidance and procedure documentation as well as new risk analysis tools. Additionally, the team create a post-monitoring process for ILI projects that will provide for added monitoring for six months following the completion of the project. If liquids are observed the plan will continue until no liquid is present. These changes will improve the efficacy of the cleaning projects and reduce the OP risk associated with this maintenance activity.

The following section describes the Program execution strategies.

7.0 Long Term Program Execution Strategy

PG&E has developed several programs to address the risk of large OP events. Each program has a specific objective related to OP elimination, function, and funding source. The initiatives fall broadly into three categories:

1. Human Performance (System Level)
2. Clearance Writing & Execution Improvements
3. Gas Quality (System & Station Level)
4. Overpressure Elimination Program (OPE)

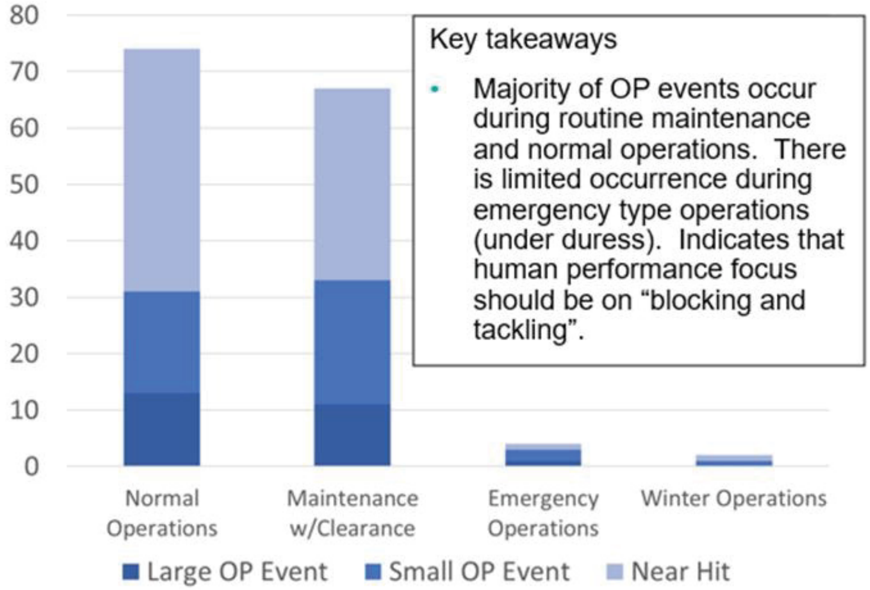
The programs individually address one of the three major sources of large OP events. Together, theprograms represent a comprehensive approach to drive the risk of large OP events to near-zero.

Each year the OP team engages in goal setting and metric tracking activities that help monitor the performance of the program as a whole. In 2021, the team tracked total OP events, large and small OP events, slam shut installations, and LVCR retrofits / rebuilds. These metrics helped to track and forecast progress as well as improved stakeholder engagement. A similar collection of metrics will be tracked in 2022. There are some differences from past years in that the California Public Utilities Commission has requested SOM (Safety and Operational Metric) and SPM (Safety Performance Metric) measures. The purpose of these metrics is to determine whether PG&E is a prudent operator and how we are using the metric data to minimize risk drivers. Our goal is to leverage these and other metrics to influence our future actions and initiatives and drive towards our stated goal of near-zero large OP events.

7.1 Human Performance

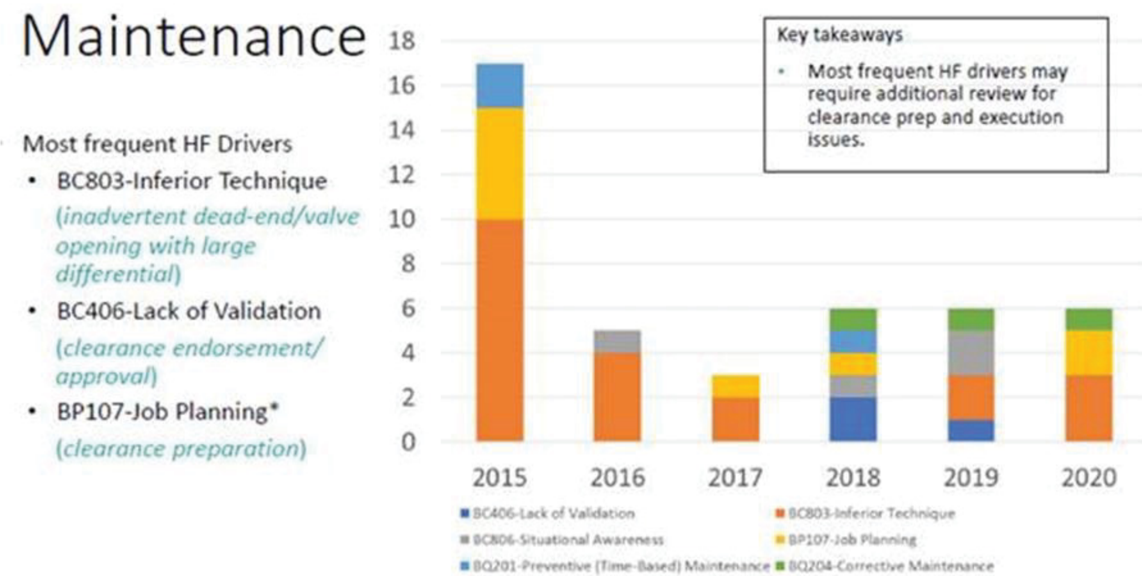
GPOM has continued to implement initiatives and programs to help improve Human Performance and limit OP risk. The team conducted an analysis of overpressure events attributed to Human Performance and found that HP-related events fell into 4 main categories: Normal Operations, Maintenance w/Clearance, Emergency Operations, and Winter Operations. The vast majority of all OP events attributed to human performance occurred within the "Normal Operations" or "Maintenance w/Clearance" categories (see below for additional detail):

Figure 14. Overpressure Events by Maintenance or Operation Type



To better understand Human Performance impacts for overpressure events, GPOM further analyzed OP event causes. GPOM has classified failures due to technical expertise gaps or inexperience as "Inferior Techniques". Examples of inferior technique include opening a value with a large pressure differential too quickly, or not considering time lags when carrying out steps of a clearance. As seen in the chart below, OP events attributed to inferior technique have drop sharply in the past 6 years. Other human performance factors include "lack of validation" and "job planning" errors which have been minimal and are mitigated through on-going training and QC processes.

Figure 15. Underlying Cause of Human Performance-Related OP Events



Human performance initiatives help reduce the risk of large OP events by preventing incorrect operationof station equipment and mitigating the impact of maintenance activities. As of 2021, PG&E has taken the following steps to address human performance risk:

1. Developed education and training programs for the GPOM organization highlighting the common causes of incorrect operation.
2. Updating and enhancing construction, maintenance, and inspection procedures to reduce the likelihood of debris in system.
3. Establish clear lines of communication and accountability within the organization
4. Collaborated with internal groups to understand and develop best practices, perform comparisons, and identify opportunities for improvement.

Dynamic Learning Activity to train field employees on HU Tools

5. Initiated installation of additional engineering controls to prevent incorrect operation. (Ex. Regulator valve installed in bypass position instead of manual valve)
6. Created reporting dashboards to track and analyze maintenance activities to provide greater visibility to measurement and control and GC construction.
7. Established pre-job briefs and checklists to increase situational awareness, validate work scope, review safety procedures, and understand work plan.

8. Implemented additional communication and validation processes to reduce human performance related equipment failures, including: Tailboards, Two-Minute Rules, Self-Checking STAR (Stop, Think, Act, and Review), Stop When Unsure, etc.

Partnering with the Gas Pipeline Operations and Maintenance (GPOM) organization, the OPE Program is collaboratively working together to understand better approaches to incorrect operations and human performance errors. The HU program is developing a parallel HU Road Map which will have additional detail about long term plans and will be referenced in future OP Road Map publications.

7.2 Gas Quality

Gas quality continues to be an area of focus at the system and station level. The plan outlines the specific strategy and equipment deployed by FIMP to help sustain a high level of gas quality for PG&E customers. Below is a table summarizing the various standards and their purpose:

Table 20. Summary of Gas Quality Strategy and Purpose[59]

Standard / Specification:	Purpose:
Hydrogen Sulfide (H_2S)	Specifications that work together to limit the risk of internal corrosion. The moisture specification ensures water will not collect in the pipeline under normal operating conditions. And the other gas specifications limit corrosion effects should waterbe present in the system.
Carbon Dioxide (CO_2)	
Oxygen (O_2)	
Moisture (Water)	
Hydrocarbon Dew Point	Specifications that work in parallel to ensure that hydrocarbonsdo not condense into liquid form and negatively impact the system.
Liquids	
Maximum / Minimum Temperature	Specifications that establish the high and low temperature limits. Preventing high gas temperatures prevents pipe wrapdamage. Preventing low gas temperature prevents Joule Thomson cooling that accompanies rapid pressure reductions.
Merchantability	Prevent debris and other substances from 3rd parties from entering the system.
Bio-methane Requirements	Limits specific bio-methane constituents from entering the system.

To ensure the gas within the system meets the guidelines in the established standards, PG&E relies onvarious types of gas monitoring equipment. The gas monitoring equipment collects and transmits datato Gas Control via SCADA for review. The types of gas monitoring equipment include the following:

- **Conventional Gas Chromatographs** – Measures hydrocarbons (C1 through C6), nitrogen andcarbon dioxide for use in calculating heating value and specific gravity.
- **Sulfur Chromatographs** – Measure several sulfur compounds, including H_2S and the odorant compounds. They are not able to test for elemental sulfur.
- **Moisture Analyzers (on-line)** – Monitor the amount of water vapor present in the natural gas atcritical locations.

[59] "Gas Quality Management Plan", Facility Integrity Management & Technical Services, PG&E, Apr. 9, 2019

- **Hydrocarbon Dew point Analyzer** – Monitors the hydrocarbon dew point of natural gas. Thereis currently only one unit installed; it is located at Sherman Island.

PG&E has developed preventative operational standards to minimize the risks of contaminants in the system. If contaminants are known or detected in the system, there is an established process and procedure to address specific contaminants. More detailed information can be found in the Gas Quality Management Plan; the second iteration of this plan was issued in March 2022. In addition to the above, additional steps are being taken to further improve Gas Quality and limit the risk of large OP events.

At the system level, filter separators are being installed at key locations within the system that are known to collect unacceptable quantities of liquid to improve the quality of gas entering the system. These filter separator installation projects are developed and funded outside of the scope of the OPE program. Addressing gas quality issues at a system level increases the effectiveness of initiatives at the station level. At the station level, the company has implemented a highly focused short-term program to install sulfur filters at all locations and desiccant filters at strategic locations. These are further described below.

7.2.1 Sulfur & Desiccant Filter Installation


Typical above-ground filter installation

Gas quality issues have been identified as one of the common causes of regulator valve failure at both transmission and distribution regulator stations. Sulfur, liquid, or miscellaneous debris in the system increases the risk of a large OP event if they are able to find a way to the regulator valves or the regulator valve pilot tubing. Regulator valve diaphragms can be worn out very quickly when exposed to black powder or other debris and pilot tubing can be clogged by sulfur or moisture in the system. When the pilot tubing becomes clogged by debris or liquids, the control pilot is unable to properly regulate pressure.

When installed, these filters should increase the reliability of a pilot-operated regulator. When combined with slam shut devices and pressure monitoring, the added installation of filtration represents a cost effective, comprehensive approach to increasing reliability and reducing the risk of large OP events. Sulfur and desiccant filters specifically target liquid, sulfur, and black powder elements in the system. Installation of these filter devices has been expedited due to the relative simplicity of their installation as well as their potential to reduce OP risk.

The current company policy is to install sulfur filters in the tubing upstream of the regulator pilot valves for all pilot operated regulator stations in their distribution and transmission systems. We have also created and implemented an alternative policy to install desiccant filters in a similar position at select locations known to have excessive liquid in the system.

As of June 2021, there is currently a stand-down on installing pilot filters as they have been determined to contribute to regulator control issues and overpressure events. In certain locations, the sulfur-gon filters have been less effective than originally planned. The filters appear to become clogged with debris at a faster rate than anticipated. This has created a potential risk vector for OP. As such, the sulfur filter installations continue to be on hold; though, the OP team is working with filter fabricators to test alternate filter internals to resolve the known issues with filter performance. It is anticipated that once an approved vendor(s) is chosen, the resumption of the sulfur filter installation program will commence on a targeted basis.

7.3 Overpressure Elimination Program

The Overpressure Elimination Program is the next phase required to continue reducing and eliminating the risk of large OP events. We are currently pursuing a strategy of installing secondary OP protection, filtration, and increasing system visibility in the control room through the use of pressure monitoring devices for pilot-operated regulating stations and large volume customers[60] (LVC). The company plans to assess and rebuild or modify LVC facilities to meet current design standards which incorporate secondary OP protection.

7.3.1 Pilot-operated Regulator Stations – Distribution & Transmission

Execution Strategy

The current strategy to complete the slam-shut device installations is to prioritize installations at stations that are currently equipped with SCADA equipment. The equipment allows us to monitor, gather, and process real-time system performance data and identify when a system is experiencing an OP event condition before a slam shut device engages. Along with these modifications, we have updated the pilot-operated regulator station design standard to include these design changes. The updated standard requires future rebuilds or new installations conform to the best OP risk reduction practices. We have also established a capital program to install SCADA at a number of stations. The slam shut installations and future SCADA installation work will be bundled to create cost and labor efficiencies. Following the installation at SCADA-equipped stations, the remaining stations will be evaluated, and slam shut device installations will be prioritized. As of 7/1/2022, 754 distribution stations have had slam-shut devices installed.

7.3.2 Large Volume Customers w/Regulator (LVCR) – Transmission

LVCs are classified as either transmission or distribution based on design pressure. LVCs that operate above 60psig are considered transmission assets and have a higher OP risk based on the number of historical OP events. The transmission LVC efforts are funded by the 76G program.

Execution Strategy

Several LVCRs are inconsistent with current design standards or their condition warrant a rebuild. LVCRs that are in good condition and are close to meeting current design standards will be retrofitted with a slam shut and pressure monitoring devices. The difference between an LVCR and an LVC is that the LVCR includes a primary regular set. This regulator set provides an additional pressure cut before the MSA. When this scenario exists, the asset is classified as LVCR. In some cases, stations may require additional modifications or component replacements to conform to standards. To address the rebuild population, our plans to fabricate and install dual run regulator station that meets current design standard for pilot-operated regulation stations. The stations will also be equipped with a slam shut device and gas pressure monitoring devices.

The filter and slam shut device installations for pilot-operated regulator stations and large volume customers will be executed in parallel to increase the pace of overall risk mitigation. The upgrades to pilot-operated equipment are anticipated to be executed over a 10-year period, with

[60] Large volume customers are those customers that use 40,000 scfh of gas or 1,000,000 scfd.

the expectation that 50% of the pilot-operated stations will have secondary OP protection installed by the end of 2022. LVCR rebuilds and retrofits are targeted for completion by the end of 2024.

7.3.3 Large Volume Customer Meter Set Assemblies (LVC MSA) - Transmission

Execution Strategy

Similar to the LVCR population, some LVC MSAs are inconsistent with current design standards, some operating conditions warrant upgrades, and some have lacked proper maintenance in the past. In addition, some LVC MSA equipment cannot handle the dynamic flow of customers based on overpressure event findings from the past 5 years. We have found that in some instances rapid shut-in of gas from the customer side has resulted in overpressure events.

Current strategy includes multiple initiatives to gather data for analysis and mitigation. A condition assessment for transmission LVC MSAs has been completed. The condition assessments include the age, condition, design configuration, and equipment installed at each location. The condition assessment has been completed and 159 sites require the installation of token relief valves. 60 of these sites have been deemed high priority. The team is in the process of performing the token relief valve installations. A long-term process has been created to prioritize the LVC MSA population for upgrades.

The team has also completed an update of the LVC MSA design standard. We have identified LVC MSAs that have setpoints at or near MAOP which need to be addressed for OPE potential. These meter sets were not originally included in the system-wide set point reduction.

7.3.4 Large Volume Customer Meter Set Assemblies (LVC MSA) - Distribution

Execution Strategy

We have requested for the Distribution Integrity Management organization to evaluate maintenance and design of Distribution LVC MSA and implement a plan to improve performance against over-pressurization. At this time, we are not currently addressing this asset population. The majority of distribution large volume customer meter set assemblies (LVC MSAs) have spring-operated regulation equipment and operate at pressures that have minimal overpressure risk.

7.3.5 Low Pressure Systems - Distribution

Execution Strategy

Multiple improvements have been implemented to reduce the risk of an OP on Low Pressure (LP) Systems. Improvements included installation of system reliefs, reduction of LP systems by a third, and installation of slam-shut devices at regulator stations (tertiary layer of over pressure protection). Additionally, system relief valves were installed prior to low pressure slam shut installations. These valves are a fourth level of OP protection and are not required by code. A study was performed that indicated many LP stations are no longer sized to flow a wide-open failure of the regulator and monitor set.

Following the 2018 Merrimack OP event, the OP team immediately re-evaluated Low Pressure Systems. The evaluation concluded that LP assets were susceptible to the same type of failure that resulted in the Merrimack OP event. However, the probability of a low-pressure OP event occurring with high consequences is low. Recognizing the status of the current LP system, the

OP Elimination Program is focused on two key areas: enhancing the existing slam-shut device and analysis of alternative upgrade mitigations.

The OP team has identified the population of at-risk low-pressure systems. To better understand the risks and develop mitigations, two management of change (MOC) sessions were held with key stakeholder to evaluate, discuss, and ultimately select mitigation options.

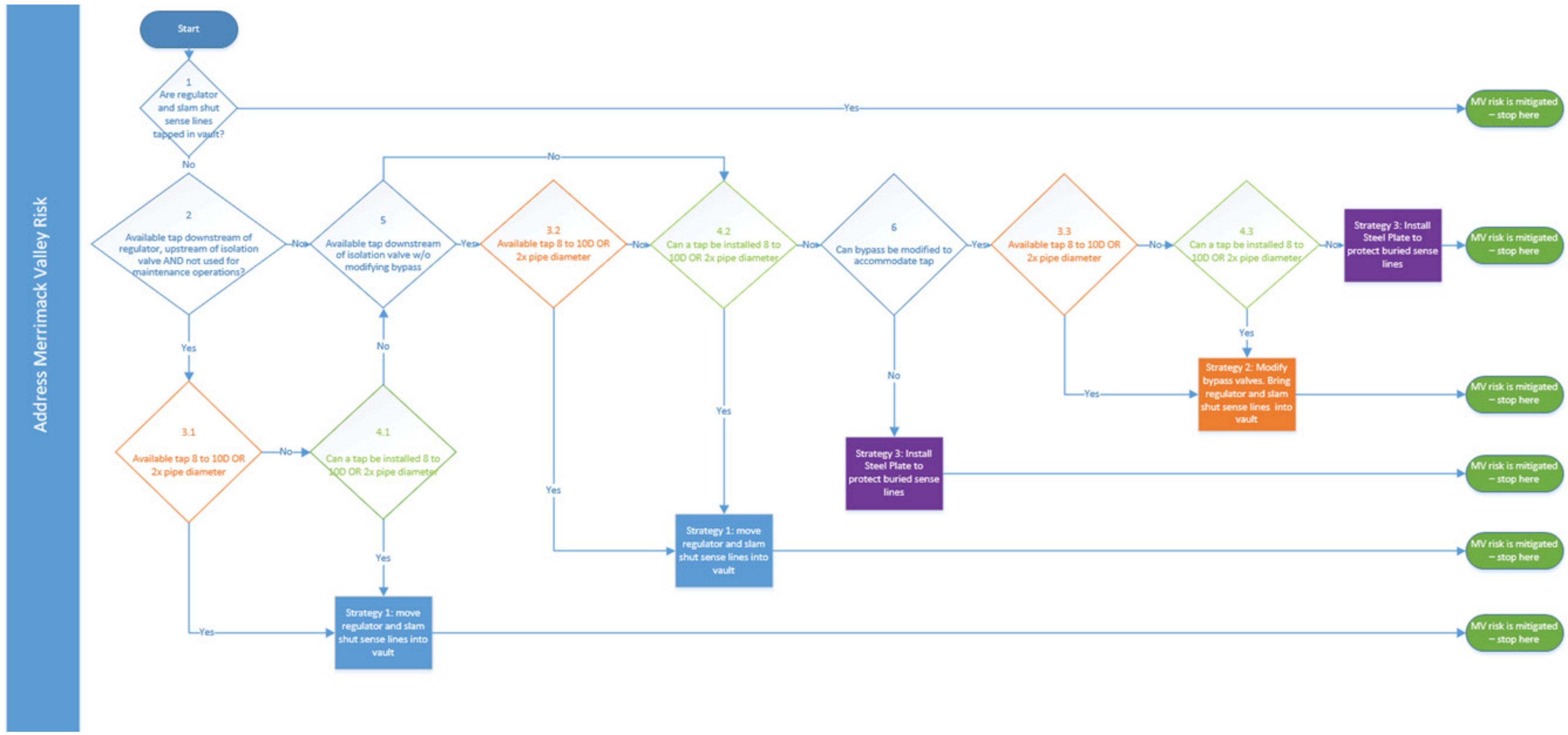
Enhancing the existing slam-shut device will prevent the Merrimack OP event failure from occurring. The team initially executed a two-phase, six-month pilot study to test the effectiveness of reactivating the under pressure shut off (UPSO) on existing slam shuts. Reactivation of the UPSO shut off was determined to be unreliable, so the team shifted focus to other strategies. In total, two core strategies were developed to address the LP risk.

The first mitigation requires that the subject station have an available tap that is not currently being used by maintenance. Also, the tap location must be downstream of the regulator or downstream of the isolation valve without modifying the bypass and is eight to 10 diameters away from the source of turbulence. Installing sense lines at locations that meet these requirements require no civil work or vault mitigation. Should the majority but not all of the requirements be met, a new tap will be installed. Adding a new tap will require civil work and will require a customized design for each instance. The second strategy involves modification of the bypass valve to increase downstream piping before a new tap can be installed. As with the first strategy, should a new tap be required a customized design and civil work is required. And the final strategy calls for the sense lines to be installed outside of the vault and protected in place. This strategy requires significant work scope, as excavation, permitting, civil, and piping work is required.

The team has completed significant scope to develop and plan the scope of this program. Multiple white papers have been developed summarizing the need for modification and to document the decision making process from multiple internal stakeholders. The stakeholders have been involved in molding the strategic direction of the effort and validating the technical requirements. Once the scope was solidified, the team developed a decision tree to categorize the types of mitigations to be deployed. A desktop review was subsequently completed to determine the number of stations that fall into each strategic category. As of June 2022, 67 fall into category 1 and 2; and 5 fall into category 3. Another 55 stations required field verification before they can be categorized.

As of June 2022, the team is in the process of standing up the broader installation program. Pilots are also in development to validate the proposed mitigations for each category. Six HIS stations will be included in the first pilot to determine proper mitigations. The current target is to tackle the stations that fall into category 1 by June of 2023. The remaining stations will be mitigated in 2024 and beyond.

Figure 16. Low Pressure Residential Stations Under-Pressure Mitigation Decision Tree



8.0 The Path Forward

A strategy to drive the risk of large OP events to zero over a ten-year period has been developed; largely based on modifications to pilot-operated equipment. It should be noted, however, that the strategy to reach this objective is continuously reviewed and therefore subject to changes resulting from new lessons learned and the potential use of new technology. Aspects of the OPE program are continuously evolving due to the complexity and criticality of some of the stations, and as additional knowledge is gained. Therefore, it is anticipated that this roadmap will continue to evolve and be updated on at least an annual basis.

Each year the team evaluates the completed, in-progress, and planned overpressure program initiatives. Initiatives are added and tracked on an internal OP priority list. Each priority project or effort is assigned milestones and an owner to ensure that regular progress is made, and any potential roadblocks are appropriately addressed. The development of the OP Priority list is a collaborative effort across multiple stakeholder groups within PG&E. The team held a series of "OP Ideation" meetings with various groups to determine which aspects of their routine work would or could constructively impact OP risk mitigation goals. Meeting attendees were asked to make project or initiative recommendations. The internal LEAN team then gathered, summarized, and categorized each of the more than 80 suggestions and recommendations. The OP Team then asked the impacted Directors to review and agree on OP Priorities that should be targeted for 2022. The 2022 OP priority list can be found in the appendix of this document as item 10.12. The OP Initiatives lists now tracks more than 30 active projects, programs, or data collection efforts in support of the OPE program.

The programs in the future roadmap have been prioritized based on potential consequences and have been identified as either a short-term, medium-term, or long-term mitigation. The timeline for implementation of these programs can vary significantly – some will be able to be completed in a manner of months while some will take years to complete.

For example, the current thinking is that the current complex / control valve stations will have the OP risk essentially mitigated once they comply with the Control Valve Transmission Regulator Station design standard (H-19) and a robust obsolescence management program has been implemented. Complex stations typically have multiple design characteristics (such as bi-directional flow, very high capacities and pressures, and multiple lines entering and exiting the station). As such, the H-19 stations do not have a common failure mode risk by design. Therefore, the plan is to not include any specific mitigations in the OPE but rather utilize existing station rebuild and component replacement programs in order to reduce the OP risk at these stations. The drawback is that the mitigation timeframe is likely to last several decades.

However, an analysis of the magnitude of the pressure cuts across these complex facilities has been completed. The results are shown in Appendix 10.3. The current plan is that the stations with the largest pressure cuts will be prioritized first for rebuilds or retrofits, specifically those in the 4+ range. This includes all of the company's terminals. Appendix 10.4 contains additional information about the program strategy moving forward.

Spring or self-regulating devices (governed by the Spring-Operated Regulator Station [H-10]) are found in the distribution system, typically have proven to be very reliable, and do not have a significant history of failure leading to large OP events. However, the pressure cut across some of these stations can be several hundred psig and, if the European Union standard were to be applied, would require some type of secondary overpressure protection device. No final decision has been made, but if a secondary OP device is installed at some or all of these facilities, it most likely would not occur until all of the pilot-operated station work was complete.

The following is a summary road map of the initiatives and programs that have or will occur to fully execute the OP Elimination program. Each of the initiatives is listed in priority by category type.

8.1 OPE Program Road Map and Summary Status (Pending Scope)

8.1.1 Pilot-Operated Regulator Stations Program (Transmission & Distribution)

- **Mini-AT Measuring Points (MSA):**

  ✓ Identify | ✓ Initiate | ✓ Plan | Do | Check

  2022 Update: 1,113 MiniAT data points continue to be reviewed daily via the Abnormal Pressure Report for potential pressure excursions. The team has proposed pulling MiniAT device data into Gas Control using Telvent so that data can be reviewed, and acted upon if appropriate, on a more frequent basis (we are currently planning to pull data every 10 minutes). 300 sites require MAOP validation prior to the start of a pilot program; the FIMP Risk team is currently using the MOC process to ensure alignment on the methodology that will be used to determine MAOP. Following the completion of the MAOP validation, Gas Operations has taken the lead in developing a pilot program for 400 MiniAT data devices.

  2021 Update: The team has continued to make progress on this program with 1,117 data points currently being reviewed daily. Much of the effort in 2021 was expended validating the mini-AT data, identifying, and resolving gaps. The addition of these data points has provided additional visibility throughout the system. The goal of this program is to have pressure data on assets that have historically been the source of a new of large OP events, and to review that data on a daily basis to identify any potential anomalies with the regulating equipment at these meter set assemblies. GPOM responds to all MAOP of Engineering limit breaches.

  2020 Update: In process of validating data and anticipate completion of this effort by the end of 2020. At the end of 2019, the team successfully set up the process to "flag" pressure data that required additional investigation via the Mini-AT Abnormal Gas Read Report and had successfully validated data at 620 stations. Gas Strategy & Support is currently evaluating existing system to see whether it is feasible to automatically transmit the data into the Gas Control via Telvent.

Mid Term Projects (2-5 Years):

- **System Visibility Upgrades (SCADA / ERX) :**

  ✓ Identify | ✓ Initiate | ✓ Plan | Do | Check

  2022 Update: The number of SCADA visibility points grew from 1,409 to 6,496 in 2021. This enabled greater visibility across the system to recognize both OP events and Abnormal Operating Conditions (AOC). Enhanced visibility allows us to identify more opportunities for improvement. The pressure monitoring devices allow Gas Control to receive early warning precursors to conditions that may lead to an OP event. The early notice of a potential issue allows the maintenance crews more response time to resolve the issue before an OP event occurs.

Figure 17. Total OP Events and SCADA Point Visibility on the System (2012-2021)

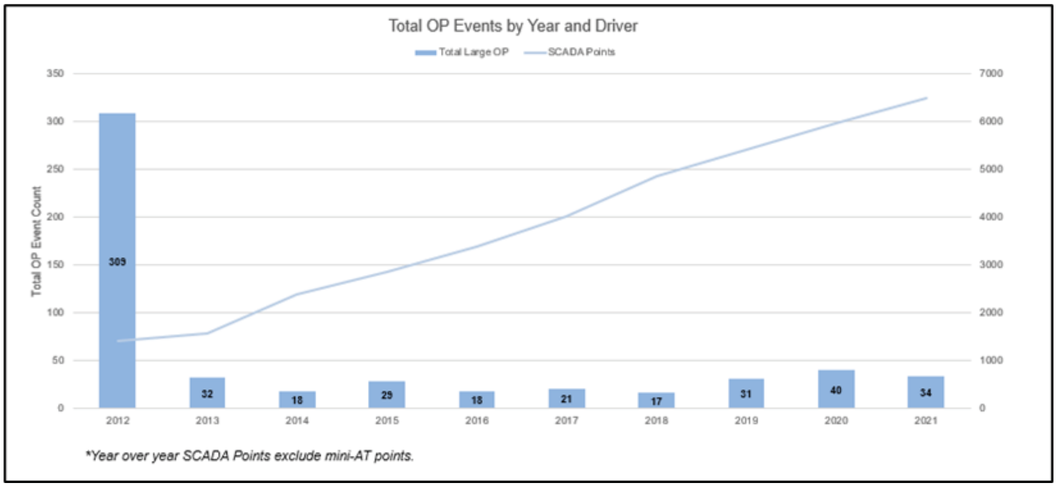
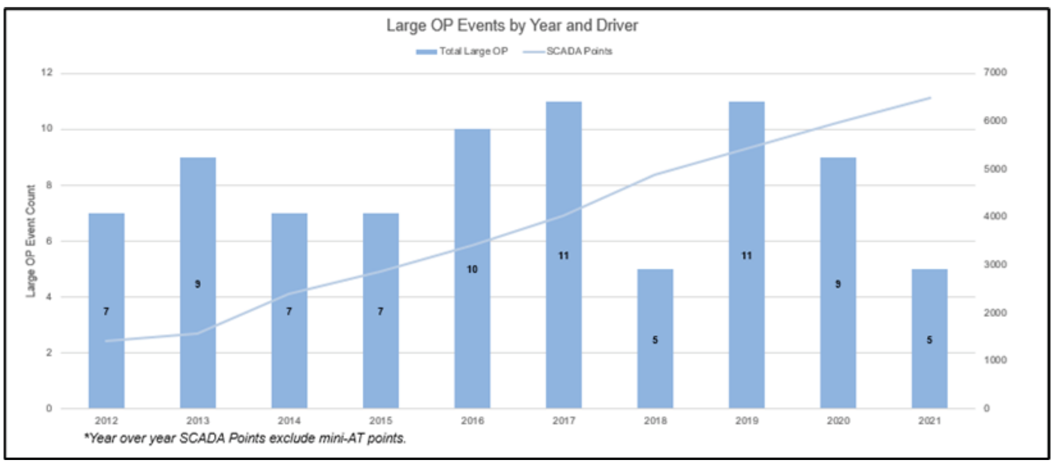


Figure 18. Large OP events and SCADA Point Visibility on the System (2012-2021)



The SCADA visibility team is currently in the process of collecting and cleaning source data in order to facilitate the development of a predictive model. The development of the model is currently on hold due to funding constraints. However, the planned model will leverage past trends and leading indicators to provide early alarm and potentially warn of an eminent OP before it occurs. The Data Management team will be contributing to the base model development with input from the SCADA team. After the model has been completed, it will be tested for efficacy, and if successful will be pushed to production for broader use. A procedure will include a process for reporting, reviewing, and mitigation OP events using leading indicators model. The process will include thresholds for site visits to investigate potential OP alarms.

2021 Update: The SCADA visibility program continues to move forward. The OP team, in collaboration with other stakeholder groups, is developing a process for alarm management data to identify leading indicators to prevent overpressure events. The procedure will include a process for reporting, reviewing, and mitigation OP events using leading indicators. The process will include thresholds for site visits to investigate potential OP alarms.

2020 Update: One of the key lessons learned for this program has been addressing interferences with wireless signal transmission. Crews in the field must observe current or account for future planned conditions and perform installations to avoid conflict. Examples of interferences include trees, walls, etc. As of March 2020, all 135 of the legacy ERX have been transmitted to Gas Control.

2019 Update: The system visibility upgrade program aims to identify critical regulator stations where additional visibility would improve reliability and mitigate OP risk. Stations that are identified will be equipped with SCADA or ERX which will send operational data to Gas Control. **Note: The visibility program is not included in the scope of the OPE program.*

- **Sulfur Filter Installations:**

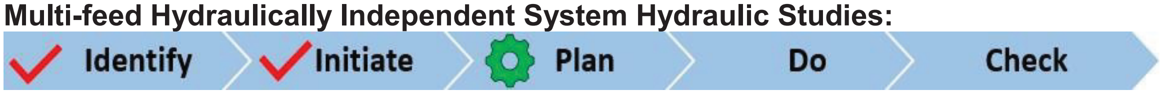
2022 Update: This program continued to be suspended due to resource and technical constraints. However, near the end of 2021 the filter fabricators provided new models that addressed some of the previous technical issues. A pilot has been planned to install the new filters in several locations to test efficacy. If the results are positive, bulk orders will be placed and the sulfur filter installation will be re-initiated. Re-initiating is not anticipated to begin prior to 2023 at the earliest.

2021 Update: The sulfur filter installation program remained suspended throughout 2020. PG&E continues to work with filter fabricators to resolve the technical issues surrounding filter performance. The team is currently evaluating multiple options to improve the filter technology, replace with alternatives, or remove the sulfur filters entirely. It is anticipated that this program will resume in Q3 of 2021.

2020 Update: The sulfur filter installation program is currently suspended. The program is currently 19% (298 stations of 1569 complete) complete with the expectation that the entire program will be completed once the team gains confidence that the technical issues surrounding the sulfur filter performance have been addressed.

2019 Update: Sulfur filters will now be installed during normal maintenance activities. As mentioned previously, the filters increase the reliability of the system by removing potentially harmful liquids and debris. This project is currently in progress and is expected to complete by the end of 2020.

- **Multi-feed Hydraulically Independent System Hydraulic Studies:**



2022 Update: The team continues to work on identifying the Multi-feed HIS system assets in order to develop a mitigation plan by end of 2022.

2021 Update: The team continues to work on identifying the Multi-feed HIS system assets in order to develop a mitigation plan. A preliminary mitigation plan is anticipated to be completedby 2021, with implementation to begin in 2022.

2020 Update: This project is in the early stages of development. To-date, the OPE team has identified the assets that fall into this category. As the program is further defined, the team willdetermine how to properly address secondary OPP for critical stations.

2019 Update: During the course of execution, certain stations may be deemed too critical to be shut in. Such cases require a further review by Gas Planning to determine acceptable secondary OP equipment alternatives. The OPE team has developed a decision tree to help identify this population of stations. This effort will be on-going and be executed in parallel with the slam-shut installation program.

- **Bypass Valve Mitigation Program:**

2022 Update: Administrative controls continue to be the primary mitigation for bypass valve related OP risk. The mitigation plan is currently in develop with a target completion date of 2022. The team will first need to verify the population of large volume customers (LVC) assets that utilize manual bypass valves before a comprehensive mitigation strategy can be deployed. A strategic white paper is currently in development for single and leaking bypass valves for all stations, not just LVC MSAs.

2021 Update: The OP team is planning to develop a decision tree to identify the locations to beupgraded as part of annual maintenance. In the meantime, administrative controls have been developed that now require superintendents to operate any single bypass valves.

2020 Update: Currently, the complete population of manual bypass valves needs to be verified.The team is developing programs to identify the populations and consider appropriate station modifications to eliminate these valves.

2019 Update: Bypass valves that currently exist on low- and high-pressure single run station willneed to be modified. Solutions may include adding regulation, installing blind flanges, or removing valves. This program is currently in the planning stage.

- **Coalescing Filter Installations:**

2022 Update: The coalescing filter installation program effort has been placed on hold. The team focused on re-starting the sulfur filter program. At this time, the team is currently evaluating the new approach and timeline for this effort. No target date has been set.

2021 Update: The coalescing filter installation program completion target date has been revisedto begin the program in 2022. After evaluating the path forward, a completion target date will be set.

2020 Update: The coalescing filter installation program completion target date has been revised. The original plan called for the program to be completed by the end of 2021.

Currently, the plan is to begin this program at a later date (possibly 2021) and set a new target date at that time. This program has been moved from the "near term" category to the "mid-term" category.

2019 Update: Coalescing filters will now be installed during the course of normal maintenance activities. These filters increase system reliability and reduce OP risk by removing liquids from the system. This program is planned to be complete by the end of 2021.

Long Term Projects (5+ Years):

- **Distribution Pilot-Operated Regulation Station OPE Program:**

2022 Update: 281 slam shut devices were installed throughout the system in 2021. The team continues to meet objectives and targets with this program. In 2022, the team planned to install an additional 192 stations with slam shut devices, but even that number is under review as of the publication of this document. The target has decreased from previous years due to the complexity of the remaining stations and impacts from other high priority work. We are currently on track to meet our objective to install secondary overpressure protection on all pilot-operated distribution regulation stations by 2025, which is consistent with our current rate case filings.

2021 Update: 510 stations were equipped with slam shut devices across the system at the end of 2020. The OPE team is targeting 250 stations for slam shut installations in 2021. The target has been increased from previous years based on the decision by senior leadership to prioritize this program.

2020 Update: 347 stations were equipped with slam shut devices across the system at the end of 2019. The SCADA Visibility team has been leading the planning and execution of the slam shut installation with input from Gas Planning. The OPE team is targeting 200 stations per year to have slam shuts installed for 2020, 2021, and 2022.

2019 Update: The scope of this program includes the installation of slam shut devices throughout the gas distribution system. This program will develop project scope, schedule, and budget to engineer, design, and modify each station. Execution of the program plan, engineering, and procurement is included in this program. It is expected that the distribution regulator station modifications will be completed by end of 2028 as part of multiple General Rate Cases going forward.

- **Transmission Pilot-Operated Regulation Station OPE Program:**

2022 Update: Per last year's update, the program is still in the planning phase. The OP Team continues to collaborate with Gas System Planning to develop and clarify scope. The target date for this work remains unchanged and is scheduled to begin between 2023 and 2026. However, due to the outsized customer outage risk associated with many of the transmission regulation stations, it is currently anticipated that slam shuts will be installed on these stations on a limited basis. FIMP is still working with Gas System Planning to determine criteria for slam shut installation for these stations.

2021 Update: The program is currently under review due to concerns by Gas System Planning that the reliability risk is unacceptably high. The OP team is currently working with Gas System Planning to establish a decision tree and work plan for this asset population. Currently, the work is slated to occur between 2023 and 2026.

2020 Update: The program is currently under review due to concerns by Gas System Planning that the reliability risk is unacceptably high.

2019 Update: This program will develop project scope, schedule, and budget to engineer, design, and modify each of the 192 transmission stations. Execution of the program plan, engineering, and procurement is included in this program. It is expected that the transmission regulator station modifications will be completed by end of 2028 as part of multiple Gas Transmission and Storage rate cases going forward.

- **Low Pressure System Slam Shut Modification:**

2022 Update: A two-phase six-month pilot was conducted to determine if reactivation of the under pressure shut off (UPSO) would mitigate under pressure risk. The UPSO was reactivated at eight stations through the fall and winter. The team discovered that the UPSO was not reliable and thus not an adequate solution for under pressurization. The team has developed 4 strategies to install sense lines inside or outside the vault depending on existing conditions. It is expected that these installations will begin in the third quarter of 2022 and complete by 2024.

2021 Update: The team continues to work with internal stakeholders and external partners to evaluate potential failure modes. Two MOC sessions have been held to discuss and evaluate OP mitigation options. Seven options were considered, with the team settling on two preferred options. For dual vault stations, the under-pressure sense line is to be reactivated. Single vault stations will have an additional sense line added for under pressure. If either option is not feasible due to inside the vault constraints, external sense lines will be installed and protected in place. An implementation plan, estimate, and schedule are currently in development. It is anticipated that a pilot program to test the effectiveness of these options will begin in 2021.

2020-04 Update: Low pressure systems were previously modified with secondary OP protection equipment (slam shut devices) and system relief valves, in the early 2000s. As a result of the Merrimack Valley OP Event, PG&E has re-evaluated their low-pressure systems to ensure all failure modes have been mitigated. PG&E is working on multiple solutions to mitigation under- pressurization on low pressure.

8.1.2 Large Volume Customer Program

Near Term Projects (0-2 Years):

- **LVCR MSA Assessment for Short-term Upgrades:**

Identify | Initiate | Plan | Do | Check

1 Thermal Relief Typical Installation

2022 Update: In 2021, the complete population of Transmission LVCs that required token / thermal relief valve installations was identified and prioritized. The population was separated by division and engineering reviewed each station to evaluate the existing configuration of each station. A few of the stations did not have the required line taps and thus will be address separately from the immediate thermal relief valve installation effort. A bill of materials was created for each station which includes an appropriately sized thermal relief valve. The program will begin once material is received. It should be noted that this program has been impacted by the on-going global supply chain issues which have prevented timely delivery of materials. However, the program remains on track to complete the installations by end of 2023 and will take approximately 1 year to complete, once started.

2021 Update: The LVCR MSA assessment will be conducted to identifythe population of LVC MSAs lacking thermal reliefs. Currently, 54 locations have been identified as potential candidates for thermal relief valve installation. The team plans to review the sites and determine the proper secondary overpressure protection for each location, either slam shut or thermal relief valve. After the reviews have been completed, an execution plan will be developed, and the installations will begin in 2021. Also, a criterion will be developed to determine the appropriate thermal relief set points to ensure alignment with the Set Point Standard and equipment required. The MSAs will be prioritized and mitigated in phases; the initial 54 were chosen because thosecustomers have not been using gas over 50% of the time.

2020 Update: The LVCR MSA assessment will be conducted to identify the population of LVC MSAs lacking thermal reliefs. A criterion will be developed to determine the appropriate thermalrelief set points to ensure alignment with the Set Point Standard and equipment required. The MSAs will be prioritized and mitigated in phases.

Long Term Project (5+ Years):

- **LVCR MSA Process for Long-term Upgrades:**

Identify | Initiate | Plan | Do | Check

2022 Update: The evaluation of long-term upgrade options is currently in progress and will continue throughout 2022. The team has identified broad categories for long term upgrades including component replacement, testing, and added visibility via SCADA. There will is also potential for a subset of MSAs to be deactivated as part of the IIP projects. A deep dive analysis is planned for next year with the ultimate goal of executing 40 projects in 2023. The majority of transmission capital OPE dollars identified in the 2023 General Rate Case (GRC) will be allocated to upgrade these assets.

2021 Update: The team continues to identify the LVCR MSA population requiring upgrades. Once determine, the selected LVCRs will be prioritized according to yet to be determined riskcriteria.

2020 Update: The long-term upgrade program will focus on developing a process to identify required data points and evaluate historical issues that should be included into a risk criterion.The LVCR MSA population requiring upgrades will be prioritized according to yet to be determined risk criteria.

8.1.3 Large Volume Customer – Primary Regulator Sets Program (LVCRs, Transmission)

Long Term Projects (5+ Years):

- **LVCR Regulator Station Upgrade Program:**

Identify | Initiate | Plan | Do | Check

2022 Update: A total of 46 LVCR rebuilds have been completed as of December 2021. 16 LVCR rebuilds were completed in 2021. The OP team plans to complete 17 LVCR rebuilds in 2022. Below is a summary of complete and planned activities:

LVCR Program	2018	2019	2020	2021	2022 (Forecast)	Total (inc. forecast)
Rebuilds	4	13	10	2	6	35
Retrofits / Component			3	11	10	24
Retirements / Downrates				3	1	4
Totals:	4	13	13	16	17	63

2021 Update: A total of 27 LVCR rebuilds have been completed as of December 2020. 10 LVCRrebuilds were completed in 2020. The OP team plans to complete 6 LVCR rebuilds in 2021.

Below is a summary of complete and planned activities:

LVCR Program:	2018	2019	2020	2021 (Forecast)	2022 (Forecast)	Total (inc. Forecast)
Rebuilds:	4	13	10	6	7	**40**
Retrofits / Component			3	15	17	**35**
Retirements / Downrates				4	3	**7**
Totals:	4	13	13	25	27	82

2020 Update: The LVCR rebuild program continues to progress as planned. In 2018, 4 rebuildswere completed and in 2019, 14 rebuilds were completed. In 2020 the tentative goal is 13 additional rebuilds.

2019 Update: This program will develop project scope, schedule, and budget to engineer, design, and modify LVCRs. Execution of the program plan, engineering, and procurement is included in this program. This program is currently in progress and is expected to be completedby end of 2023.

8.1.4 Spring-Operated Regulator Stations (Farm Taps, High Pressure Regulators)

Long Term Projects (5+ Years):

- **Pressure Regulation Standard Review (Farm Taps, High Pressure Regulators)**:

  Identify | Initiate | Plan | Do | Check

  2022 Update: The team has reviewed the overpressure event data over the past ten years and has determined that there is not a significant overpressure risk with this class of equipment. Therefore, there is currently no plan in development to add secondary overpressure protection equipment.

  2019 Update: The team has not yet determined if the Spring-Operated Regulator Station designstandard will need to be altered to include secondary overpressure protection. The current planis to install SCADA visibility at those stations that serve more than 50 customers.

- **Spring-Operating Regulator Station Upgrade Program:**

  Identify | Initiate | Plan | Do | Check

  2022 Update: The team has reviewed the overpressure event data over the past ten years and has determined that there is not a significant overpressure risk with this class of equipment. Therefore, there is currently no plan in development to add secondary overpressure protection equipment.

  2021 Update: This program is currently in the planning phase. To date, we have not experiencedthe common failure mode OPs for this class of assets. The program remaining in the planning and evaluation phase.

  2019 Update: This program is currently in the planning phase. PG&E will need to determine ifthe design standard for this asset type will need to be modified before planning can be completed. The target completion for this program is 10+ years.

8.1.5 Control Valve Transmission Regulator Stations

Long Term Projects (5+ Years):

- **Transmission Regulation Station Upgrade Program:**

  Identify | Initiate | Plan | Do | Check

  2022 Update: The team continues to upgrade control valve transmission regulator station according to the normal lifecycle. The team has completed 8 upgrades, with a 9th scheduled for completion by the end of the year.

  2021 Update: Stations upgrades have been executed according to the normal lifecycle for this asset type. To-date, 7 stations have been rebuilt. The goal is to have 9 stations rebuilt by 2022.

  2019 Update: The proposed plan includes component replacement when necessary and ultimately a complete rebuild of the station once it has reached the end of its typical life cycle(60 years). To-date, 5 stations have been modified to the new standard.

8.1.6 OPE Management & Emerging Work

Near Term Projects (0-2 Years):

- **Re-verification of Customer Load:**

2022 Update: The re-verification of customer load initiative is currently on hold. The plan is to re-engage and kick of the process of setting up a plan and procedure for execution and organizing resources to conduct the analysis once more resources become available. The regulation engineering team has, however, shifted their focus to stations that serve low customer counts and are developing a strategy for those stations. This change is strategy was a direct result of the large OP events experienced in early 2022.

2021 Update: The re-verification of customer load initiative is slated to kick off in the fourth quarter of 2021. The team is in the process of setting up a plan and procedure for execution andorganizing resources to conduct the analysis.

2020 Update: The Gas Planning group is responsible for this program. As such, the OPE team willcontinue to collaborate and track progress to determine impacts to OPE targets.

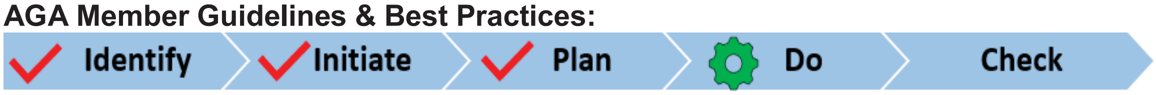
2019 Update: PG&E is developing a plan to review and verify existing client service needs. In cases where the service load has significantly changed, PG&E is planning to review each stationto insure it is properly sized for the required service.

- **Expand Casual Evaluations:**

2022 Update: The team has completed a trending an analysis of the past five years of casual analyses. The results of these analyses confirmed the findings from earlier studies, that the source of OP risk was generally related to incorrect operation and equipment failure due to debris and/or liquid obstruction. In 2022 the team will conduct an analysis of the past 10 years of casual analyses to determine if any new trends are present.

2021 Update: PG&E conducts a casual analysis to determine the root cause of a given OP event.The reports detail the circumstances surrounding the event and included detailed pressure metrics. Each report contains a corrective action that generally falls in line with established OP initiatives. As a management effort, the team is seeking peer review and management feedbackon the causal evaluations to expand scope to include small and large OP events.

- **AGA Member Guidelines & Best Practices:**



2022 Update: In 2021 the OP team leveraged the AGA SOS Survey process to gather information related to MAOP set points. The goal of the survey was to collect information from other operators and learn about their approach to set points relative to MAOP. This survey was requested in support of our set point reduction initiative. The results indicated that 14 of the 15 respondents have MAOP set points above MAOP. And the majority of operators use seasonal set points. As the set point reduction initiative continues to move forward, we will continue to collaborate with AGA and other operators to determine best practices and best fit for our system.

2021 Update: The OP team continues to engage with AGA and its industry partners to develop best practices and share knowledge. In December of 2020 we participated in an informal survey regarding the use of secondary overpressure protection devices. While the specific installation counts were not available, 22 of the 31 respondents currently use slam shut or relief valve devices to reduce OP risk. The common strategy amongst these companies indicates widespread acceptance of slam shuts and relief valves as OP risk mitigating equipment.

The OP team has reviewed and begun incorporating the new regulations set forth in the PIPES Act of 2020. The new regulations impact PG&E in the following areas:

- Distribution Integrity Management Plans
- Emergency Response Planning
- Operations & Maintenance Planning
- Pipeline Safety Management
- Pipeline Safety Practices (Records)
- District Regulatory Station Upgrades

AGA has provided a summary of the PIPES Act, the summary document is available as Appendix 10.10.

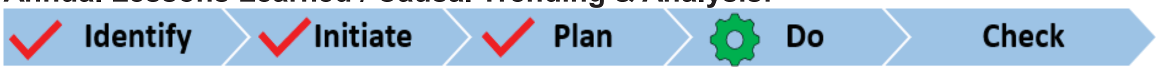
2020 Update: In November of 2018, the American Gas Association (AGA) published a white paper titled "Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event". Through its research and in collaboration with natural gas utilities the AGA including a list of recommended best practices to mitigate over-pressurization event risks. In all, the AGA provided design best practices and maintenance procedures for consideration, the details can be found in Appendix item 10.7. The AGA best practices have been incorporated into our standard procedures. A table of the procedures that align with the AGA best practices can be found in Appendix item 10.8.

- **Regulator Station Right-sizing Review:**

2022 Update: The scope of the Regulator Right-Sizing effort has been modified; the team plans to focus on evaluating regulator stations that serve hydraulically independent systems with low customer counts. The evaluation will determine equipment that better suites the operational scenario of those stations or any other mitigations required for this asset population. Following the completion of the evaluation the team will prepare a whitepaper to socialize the finding (influence the path forward), develop the list of stations with defined activities, and add them to the program schedule. The goal for 2022 is to complete the evaluation, develop a whitepaper with a summary of recommendations, and to socialize the efforts to the engineering and execution teams.

2021 Update: PG&E is in the process of defining and plan and process to conduct a system review of both transmission and distribution regulator stations. Our goal for 2021 is to engagerelevant stakeholders to develop a plan and process to review right-sizing. This program will take clearer shape in 2022.

- **Annual Lessons Learned / Causal Trending & Analysis:**



2022 Update: As part of the effort to address the sense line issues on low pressure systems, the team conducted a pilot to determine the efficacy and reliability of the under pressure shut off. The team learned through the pilot that the UPSO was not reliable and thus not a proper mitigation for the scenario. As a result, the team developed three additional strategies to install and protect sense lines to mitigate under pressure risk. OP Causal Evaluations continue to be performed for large and small OP events. A causal evaluation occurs at the request of the sponsor and requires a deep dive into the root causes of a given OP event.

2021 Update: OP Causal Evaluations have been on-going for both small and large overpressure events. The evaluations include background information, an event description, an event analysis, causes (direct, apparent, and contributing), and corrective actions. The corrective actions represent the lessons learned from the specific event but in many cases result in processand procedure improvements. Within the context of OP, lessons learned are continually appliedand refined as new information becomes available.

2019 Update: The OPE team is committed to reviewing the lessons learned on completed and in-progress initiatives in order to continually improve the program. The reviews will be conducted on an annual basis and included as an appendix item to this report. 2019 will be thefirst year the lessons learned are documented.

- **Integrated Investment Planning Review**:

2022 Update: The IIP team continues to assess the gas system to anticipate future demand, risks, and compliance changes. In 2021 the team reviewed 1,219 transmission assets with identified TIMP threats. 135 distribution assets were retired, which will have a positive impact on maintenance costs and resource utilization. The team downrated 60 miles of pipe and retired an additional 19 miles of pipe. Recommendations and reviews are occurring on a regular basis to find additional opportunities to improve the safety, operability, and efficiency of the system. The team plans to continue reviewing existing assets as well as planned future capital projects to determine if additional benefits or efficiencies can be found.

2021 Update: As part of an effort to “right-size” the gas system in anticipation of future demand, the team is currently performing reviews low pressure hydraulically independent systems when driven by TIMP compliance. As part of this review, recommendations are made regarding reconfiguration or elimination of existing stations. Although this analysis in not being funded by the OPE Program, this effort supports the OPE effort by ensuring that the stations arecorrectly sized or even eliminated, both of which will result in fewer large OP events in the future.

- **LVC Outreach Program:**

2022 Update: One of the risk categories identified early on in the program was related to impacts from large volume customer operations. The team found that OP risk increased with LVCs abruptly stopped using gas. The OP team stood up and is in the process of rolling out an LVC Outreach program to inform PG&E's customer service representatives and large volume customers about the OP risk associated with these asset types. We developed training materials and have held meetings with selected LVCs to inform and act as a resource for any questions or concerns. Our hope is that the LVCs take the presented information into consideration for their own operations and act as partners to help reduce OP risk for themselves and PG&E.

Long Term Projects (5+ Years):

- **Tap Monitoring Program:**

2022 Update: Tap monitoring will occur for a minimum of six months post In-line inspection or strength test. This effort has been implemented and is now complete.

2021 Update: The Tap Monitoring Program continues to move forward with the identification oftap and boot locations throughout the system. The team is currently evaluating which taps and boots have potential downstream impacts and are being evaluated for removal from service. In 2021, the team will be identifying locations that require moisture analyzers to be installed and developing criteria for tap and boot removal (if necessary).

2019 Update: The system includes taps or "boots" that act as collection points for liquids in the system. The boots capture liquid which is then drained during the course of normal maintenance. The company is in the process of identifying the tap and boot locations to monitortheir impact to downstream pressure regulator stations. Depending on the impact, some of the taps or boots may need to be removed.

- **MAOP Separation Valves:**

Identify | Initiate | Plan | Do | Check

2022 Update: The effort to identify the transmission MAOP separation valves and develop mitigation plan has been completed. The work will be completed as part of the 2023 General Rate Case. For the purposes of the OP program, this will be marked complete and moved to the completed activities section in the next update.

2021 Update: TIMP has completed nearly all of the reviews to identify transmission-to-transmission separation valves. The TIMP team has incorporated the planned mitigations intothe 2023 General Rate Case. All known distribution-to-distribution and transmission-to- distribution separation valves have been mitigated by DIMP.

2020 Update: The population of MAOP Separation Valves was identified in 2018. PG&E has multiple programs to address MAOP separation valves across the Transmission and Distributionsystem.

- **Gas Quality Management Plan Mitigations:**

Identify | Initiate | Plan | Do | Check

2022 Update: Please refer to the updated Gas Quality Management Plan (Appendix 10.5).

2021 Update: Please refer to the updated Gas Quality Management Plan (Appendix 10.5).

2019 Update: PG&Es recently published a Gas Quality Management Plan (Appendix 10.5) thatidentifies and provides recommendations for mitigations to reduce the impact of gas quality issues.

- **Low Pressure System Upgrades Development:**

Identify | Initiate | Plan | Do | Check

2022 Update: In 2021 the team made significant progress with this program. A white paper was developed to outline the goal, strategies, scope, milestones, and budget of the program. Various preparation work was completed to enable the success of the pilot study: set point stability tests, job aid development, onsite training, pilot station selection and approval, project management order creation, clearance documentations, material order, coordination among execution teams, etc. A two-phase, six-month pilot study was completed at eight LP stations from August 2021 to January 2022 to test the strategy of reactivating Under Pressure Shut Off (UPSO) in slam shut. The pilot result helped to identify the unreliability of UPSO in winter season and shift team's focus to the next strategies in line. Team also evaluated the options of detecting the slam shut activation and got leadership's approval for a path forward. Currently team is working on the decision tree and the desk top review to determine the strategy for each LP station and evaluating the inclusion of a Pietro Florentini stack device that will bring sense lines into the LP stations.

2021 Update: The OP team is in the process of addressing the risks associated with this asset population. In general, the current strategy is to install under-pressure sensing lines to detect under-pressurization. Options have been selected for both the single and dual vault low pressure regulator stations. For dual vaults, the plan is to reactive the under-pressure sense lines. Single vaults will likely require a new sense line to be installed. A plan is in development toselect the appropriate solution for each asset.

2020 Update: As a result of the Merrimack Valley OP event, there is a renewed emphasis of addressing OP risk of low-pressure stations. PG&E has reprioritized and will evaluate the entirelow-pressure systems to understand system risk. Evaluation of the system will include understanding demand and providing recommendations for station modifications to best suit the system.

2019 Update: PG&E has made a commitment to the California Public Utilities Commission's Safety Enforcement Division (SED) to develop an action plan for low pressure systems. The planis due to the CPUC SED by January 2020. The plan will review each of the 205 low pressure stations and provide recommendations for retrofits to ensure safety and reliability. Some itemsin consideration include fire fuses, system relief valves, and fusible links, among others.

9.0 Document Change Log

REVISION	REVISION DATE	DESCRIPTION OF CHANGES
1	July 2020	1. Additional overpressure and failure events were added to provide historical context that has influenced the development and necessity of the OPE program. 2. Charts and figures have been updated to reflect 2019 actuals. 3. Sulfur-gon status has been updated to report on the stand downs, revised timelines, and current plan forward. 4. The Coalescing Filter installation program has been delayed until 2021. 5. Updates have been made for programs and projects for the 2020 year, including known status and goals. 6. Although not reflected on the document, progress on programs will be affected by the 2020 Covid-19 pandemic.
2	July 2021	1. Updates to program progress and execution strategies 2. Charts and figures have been updated to reflect 2020 actuals. 3. Covid-19 pandemic continues; PG&E continues to experience impacts.
3	July 2022	1. Updates to program progress and execution strategies; added new OP initiatives 2. Completed updates to charts and figures to reflect 2021 actuals. 3. Covid-19 pandemic continues; PG&E continues to experience impacts. 4. The Coalescing Filter installation program continue to be on hold. 5. Currently piloting new sulfur filter material. Expect approval by end of 2022; roll-out of new program in 2023.

10.0 Appendices

Contact FIMP&TS for Appendices.

10.1 Project Ranking by Program

10.2 OPE Road Map Schedule (Exhibit)

10.3 Category A Station Overpressure Review

10.4 Additional Discussion Related to Control Valve Stations

10.5 Gas Quality Management Plan

10.6 OP Master List

10.7 AGA Leading Practices to Reduce the Possibility of a Natural Gas Over- Pressurization Event

10.8 PG&E AGA Best Practices Summary

10.9 Definition of Large OP Event and Other Associated Terms

10.10 AGA Summary of 2020 Pipes Act

10.11 General Order 58A – Standards for Gas Services in the State of California

10.12 2022 OP Priorities

10.13 OP Ideation List

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT L

PG&E'S RESPONSE TO JOINT-EI_003-Q001

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire and Gas Safety Costs
Application 23-06-008
Data Response

PG&E Data Request No.:	Joint-EI_003-Q001		
PG&E File Name:	WildfireandGasSafetyCosts_DR_Joint-EI_003-Q001		
Request Date:	August 8, 2024	Requester DR No.:	003
Date Sent:	August 22, 2024	Requesting Party:	Energy Producers and Users Coalition/ Indicated Shippers
PG&E Witness:	Karli Maeda	Requester:	Samir Hafez

QUESTION 001

Please reference Wildfire and Gas Safety Costs Exhibit PGE-2, Gas Safety and Electric Modernization Costs Prepared Testimony, page 2-AtchE-7, where PG&E states:

> "PG&E forecast a programmatic level of anticipated spend of approximately $6.1 million per year in the 2019 GT&S Rate Case for adding secondary OP protection at GT station facilities."

a. Please confirm the number of LVCR and LVCM facilities PG&E forecast it would rebuild or retrofit annually corresponding to the $6.1 million per year estimated cost.

ANSWER 001

The 2019 Gas Transmission and Storage rate case presented a forecast of approximately $6.1 million per year (2019-2022) for MAT 76G, Station Overpressure Protection Enhancements Capital. The workpaper is shown below.

Table 7-39
Pacific Gas and Electric Company
2019 Gas Transmission and Storage Rate Case
Workpapers Supporting Chapter 7, Asset Family - Facilities
Station Over Pressure Protection Enhancements Capital

Program: Station Over Pressure Protection Enhancements Capital, MAT 76G

Program Description

PG&E tracks overpressure events as a measure of pipeline safety, and is proposing the addition of additional equipment, including filtration, relief valves and other overpressure protection (OPP) devices, which will enhance pipeline safety. The capital projects in this program include the following activities:
• Installation of filters and separators at strategic locations within the system to reduce the likelihood of debris and liquids from entering the system and impacting pilot-operated regulators and monitors.
• Installation of secondary OPP devices at stations with pilot-operated regulators and monitors. These additional devices may include slam shuts valves, adding monitor valves, relief valves or alternate technologies to prevent overpressure events from occurring.

WP 7-71

	Table 1 : Station OPP Capital	2019	2020	2021	
1	Total Cost unescalated	$6,000,000	$6,000,000	$6,000,000	Table 3 Line 13
2	Escalation	1.028	1.031	1.029	
3	Subtotal	$6,165,600	$6,188,400	$6,176,400	Line 1 * Line 3
4	StanPac Allocated	$186,460	$187,149	$186,786	Note #1
5	1/7th of StanPac	-$26,637	-$26,736	-$26,684	(-1/7) * Line 4
6	Total Capital	$6,138,963	$6,161,664	$6,149,716	Line 3 + Line 5

	Table 2: Program Scope	GT Simple Stations	GT Complex Stations	LVCs	Total
7	# of Stations (Pilot Operated)	192	128	100	420

	Table 3: Estimate [2]	2019	2020	2021
8	Installation of new Technologies from Pilot Studies [2]	$300,000	$300,000	$300,000
9	Installation of Slam Shut devices [2]	$700,000	$700,000	$700,000
10	Installation of additional Regulator or Monitor [2]	$1,500,000	$1,500,000	$1,500,000
11	Installation of Relief valves [2]	$1,500,000	$1,500,000	$1,500,000
12	Modification of Control Valves to existing H19 Stations [2]	$2,000,000	$2,000,000	$2,000,000
13	Total Station OPP Capital (Unescalated)	$6,000,000	$6,000,000	$6,000,000

Notes
#1 StanPac costs allocated based on number of M&C stations along StanPac pipeline. 1/7ths of the costs allocated to StanPac removed from GT&S forecast.
#2 Based on the estimates developed by internal and external subject matter experts.

As noted in footnote #2 in the workpaper above, those forecasts were “based on estimates developed by internal and external subject matter experts”. Those high-level estimates did not include the number of facilities that the program would address in the rate case period.

In its Final Decision (D.19-09-025), the Commission recognized that managing OP incidents on PG&E’s GT system is a priority, but noted that the program appeared to be in flux[1]. It required PG&E “to track capital expenditures for this program in a memorandum account”.[2]

The workpaper above shows:

- Table 1: the total capital forecast escalated.
- Table 2: the count of GT simple stations, GT complex stations and LVCs in the total population of the PG&E system. In 2019, those LVCs included only LVCRs, and no LVCMs. Not all those facilities would necessitate OPP enhancements. At the time of building the forecast, only the total population was known, not the actual count of facilities that would need field work.
- Table 3: the various activities forecasted for the 2019 GT&S period. At the time, only retrofits activities were forecasted, and only at GT simple and complex transmission stations.

1 D.19-09-025, p. 111.
2 D.19-09-025, p. 111.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ELECTRIC DISTRIBUTION

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

CALCULATION OF REVENUE REQUIREMENT

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENT OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KARLI MAEDA

Q 1 Please state your name and business address.

A 1 My name is Karli Maeda, and my business address is Pacific Gas and Electric Company (PG&E), 6121 Bollinger Canyon Road, San Ramon, California.

Q 2 Briefly describe your responsibilities at PG&E.

A 2 I am the Senior Manager of Gas Regulation Services. I am also the Asset Family Owner for Measurement and Control assets where the focus is on the safety and reliability of gas transmission and distribution station facilities. I oversee the related risk and asset management activities.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from University of California, Los Angeles, in 2000. I am a California-Registered Professional Engineer in Mechanical Engineering and have 23 years of experience in gas engineering and operations. I am also a member of the American Gas Association and serve on the Gas Transmission Measurement Committee. Since joining PG&E's Gas Department in 2011, I have held a wide range of responsibilities for PG&E's Gas Operations Department related to: gas quality, PG&E's underground storage facilities, compressor stations, pipeline terminals, pressure regulation stations, and other facilities.

Q 4 What is the purpose of your testimony?

A 4 I am assuming the following testimony and workpapers in PG&E's Wildfire and Gas Safety Costs Application:

- Exhibit (PG&E-2), "Gas Safety and Electric Modernization Costs Prepared Testimony":
  - Chapter 2, "Gas Operations";
  - Chapter 2, Attachment C, "Recovery of Gas Statutes, Regulations, and Rules Memorandum Account (GSRRMA) Costs":
    - Section B.2;

- Chapter 2, Attachment E, “Recovery of Measurement and Control (M&C) Station Overpressure Protection Memorandum Account (MCOPPMA) Costs”;
- Chapter 2, Attachment F, “Recovery of Critical Documents Program Memorandum Account (CDPMA) Costs”; and

- Exhibit (PG&E-4), “Gas Safety and Electric Modernization Costs Workpapers”:
  - Workpapers supporting the Opening Testimony above.

I am also sponsoring the following rebuttal testimony in PG&E’s Track 2 Wildfire and Gas Safety Costs proceeding:

- Chapter 2 “Gas Operations”:
  - Section D.3;
  - Chapter 2, Attachment J, “PG&E’s Response to CalAdvocates_008-Q005”;
  - Chapter 2, Attachment K, “Overpressure Elimination Program Summary of Program Development and Long-Term Execution Plan”; and
  - Chapter 2, Attachment L, “PG&E’s Response to Joint-EI_003-Q001.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.