Originally submitted March 15, 2024
Amended April 4, 2024

2024 SB 1371 COMPLIANCE PLAN

SoCalGas

Summary of Amendments to SoCalGas's 2024 Natural Gas Leak Abatement Compliance Plan (April 2024)

The table below summarizes the changes made in SoCalGas's 2024 Leak Abatement Amended Compliance Plan, submitted in April 2024:

Chapter	Page Number	Change Made
Intro	3	Added new table to include estimated reduction based on current approved baseline, and updated cost effectiveness factor and calculations
1	22	Updated cost effectiveness factor and calculations
2	28	Updated cost effectiveness factor and calculations
3	33	Updated cost effectiveness factor and calculations
14	75	Updated cost effectiveness factor and calculations
21	97	Updated cost effectiveness factor and calculations
24	105	Updated cost effectiveness factor and calculations

Introduction

SoCalGas submits this Biennial Compliance Plan on March 15, 2024 (Compliance Plan) as part of the Natural Gas Leak Abatement Program (NGLAP or Program). Implementation of the activities for each measure will begin after Compliance Plan and associated forecasts for cost recovery as presented in Advice Letter (AL) 6277 are approved, with expected implementation in years 2025 and 2026 (2024 Compliance Period).

Forecasts presented for cost recovery associated with the measures proposed in this Compliance Plan are for activities that are incremental to safety and specific to the emission reduction goals of Decision (D.) 19-08-020. SoCalGas currently has policies and procedures in place to meet environmental and safety regulations implemented by various state and federal agencies, including, but not limited to, the federal Environmental Protection Agency (EPA) and Pipeline and Hazardous Materials Safety Administration (PHMSA), California's Department of Conservation's Geological Energy Management Division (CalGEM), Occupational Safety and Health Administration (OSHA), and Air Resources Board (CARB), and local air pollution control districts. Some of these policies overlap with Senate Bill (SB) 1371 requirements, which is addressed in the relevant chapters herein.

Due to the ongoing collaboration between SoCalGas and the relevant agencies to adjust/correct the 2015 baseline, SoCalGas is providing two scenarios to demonstrate the potential emission reductions of this Compliance Plan. Once a decision is reached, expected by the end of April 2024, SoCalGas will be able to recalculate the emission estimations utilizing the values of the agreed-upon 2015 baseline.

Emission Reductions from Official 2015 Baseline

The current approved 2015 emissions inventory baseline for SoCalGas's system is 1,592,024 MCF. This value does not include the adjustments that were proposed for Appendix 6 Identified MSA Leak emissions on February 21, 2024. Annual estimated emission reductions resulting from activities proposed in this Compliance Plan from 2025 – 2030 are currently estimated at 818,795 MCF. Therefore, the overall emissions in 2030 are estimated to be 773,229 MCF, a 51% reduction from the current approved baseline. This estimate was completed using the emission volumes from Table 1A below. Notably, the 2024 Compliance Plan is being submitted while SoCalGas and the relevant regulatory agencies are still collaborating to adjust the 2015 baseline. As such, the estimated percentage reduction and emission levels presented in this Compliance Plan may differ from the results observed after the baseline is finalized.

Table 1A: Major Efforts to Reduce Emissions (2015 Current Approved Baseline) – SoCalGas

Chapter	2025 Emission Reduction, MCF	2030 Emission Reduction, MCF	Standard Cost Effectiveness ($/MCF), (2025-2030)	Net Cost Effectiveness** ($/MCF), (2025-2030)	Net Cost Effectiveness ** with Safety Cost Benefits ($/MCF), (2025-2030)
Chapter 1 - Leak Inventory Reduction	257,399	266,921	190	163	162
Chapter 4 - Large Leak Prioritization*			NA	NA	NA
Chapter 2 - Leak Survey	149,460	149,460	71	44	44
Chapter 3 - Blowdown Reduction Activities	187,581	187,581	22	-4	-4
Chapter 14 - Aerial Monitoring (System Only)	206,596	206,596	61	35	35
Chapter 21 – Transmission Leaks and Vented Emissions	4,901	6,821	35	8	8
Chapter 24 – Storage Aboveground Leak Survey	1,416	1,416	921	894	894
Program Totals	**807,353**	**818,795**	**97**	**70**	**69**
Percentage Reduction Relative to 2015 Baseline	**51%**	**51%**			

**Emission reductions and the cost effectiveness values for Chapter 1 - Leak Inventory Reduction include the emissions from Large Leak Prioritization due to the shared expenditure and overlapping activities (See Chapter 4 for details)*
*** Net Cost Effectiveness reflects the Standard Cost Effectiveness with Avoided Cap & Trade and Social Cost of Methane Cost Benefits*

Emission Reduction Estimation Assumptions

- SoCalGas is only using baseline values that were finalized and formally approved
- SoCalGas is using leaker-based emission factors to estimate 2025 and 2030 Distribution Main and Service Pipeline Leak emissions. SoCalGas is utilizing the same emission factors that were submitted in the 2023 Annual Emissions Report to estimate emissions for Chapters 1, 2, and 4. SoCalGas is using the emission factors that were submitted in the "SoCalGas and SDG&E 2022 Aerial Methane Mapping Research & Cost-Effectiveness Summary Report" from February 2023 to estimate emissions for Chapter 14.
- Per the guidance provided during the 2024 Winter Workshop, SoCalGas is including leaks with emissions <10,000 ppm in the emission forecasting calculations for Chapter 24.
- The 2030 emissions reflect forecasted emission reductions as proposed in this Compliance Plan. The forecasted emission reductions are subtracted from the current approved 2015 baseline to estimate reductions relative to baseline.

Emission models used to forecast reductions will have some degree of variation and the final observed reduction may be higher or lower. Based on information and technologies currently available, SoCalGas is proposing to implement measures that maximize cost-effective emission reductions as reasonably as possible and then maintain the reduced emission levels through 2030 and beyond. As proposed research projects and pilots are completed, more accurate modeling may become available. In addition, as pilots are concluded, new technologies may become commercially available to further reduce emissions beyond what is currently forecasted.

In addition to the emissions forecasted to be reduced from SoCalGas's system, SoCalGas is proposing to use emerging technologies and data analytics to reduce post-meter (customer) emissions, further discussed in Chapter 14 (Aerial Monitoring). Although these reductions are not currently reflected in SoCalGas's Annual Emissions Report, these activities support the state's climate goals and the spirit of Senate Bill 1371.

Emission Reductions from Proposed 2015 Baseline

The current proposed 2015 emissions inventory baseline for SoCalGas's system is 1,902,814 MCF. This value includes proposed adjustments that were submitted on February 21, 2024. Annual estimated emission reductions resulting from activities proposed in this Compliance Plan from 2025 – 2030 are currently estimated at 818,795 MCF. Therefore, the overall emissions in 2030 are estimated to be 1,084,019 MCF, a 43% reduction from the proposed baseline. This estimate was completed using the emission volumes from Table 1B below. Notably, the 2024 Compliance Plan is being submitted while SoCalGas and the relevant regulatory agencies are still collaborating to adjust the 2015 baseline. As such, the estimated percentage reduction and emission levels presented in this Compliance Plan may differ from the results observed after the baseline is finalized.

Table 1B below, Major Efforts to Reduce Emissions, summarizes SoCalGas's proposed major activities and estimated emission reductions proposed in the 2024 Compliance Plan based on the 2015 proposed baseline.

Table 1B: Major Efforts to Reduce Emissions (2015 Proposed Baseline) – SoCalGas

Chapter	2025 Emission Reduction, MCF	2030 Emission Reduction, MCF	Standard Cost Effectiveness ($/MCF), (2025-2030)	Net Cost Effectiveness** ($/MCF), (2025-2030)	Net Cost Effectiveness ** with Safety Cost Benefits ($/MCF), (2025-2030)
Chapter 1 - Leak Inventory Reduction	257,399	266,921	190	163	162
Chapter 4 - Large Leak Prioritization*			NA	NA	NA
Chapter 2 - Leak Survey	149,460	149,460	71	44	44
Chapter 3 - Blowdown Reduction Activities	187,581	187,581	22	-4	-4
Chapter 14 - Aerial Monitoring (System Only)	206,596	206,596	61	35	35
Chapter 21 – Transmission Leaks and Vented Emissions	4,901	6,821	35	8	8
Chapter 24 – Storage Aboveground Leak Survey	1,416	1,416	921	894	894
Program Totals	**807,353**	**818,795**	**97**	**70**	**69**
Percentage Reduction Relative to 2015 Baseline	**42%**	**43%**			

**Emission reductions and the cost effectiveness values for Chapter 1 - Leak Inventory Reduction include the emissions from Large Leak Prioritization due to the shared expenditure and overlapping activities (See Chapter 4 for details)*

*** Net Cost Effectiveness reflects the Standard Cost Effectiveness with Avoided Cap & Trade and Social Cost of Methane Cost Benefits*

Emission Reduction Estimation Assumptions

- With the exception of the Appendix 6 Identified MSA Leak category, SoCalGas is only using baseline values that were finalized and formally approved. For the Appendix 6 Identified MSA Leak category, SoCalGas is using the proposed baseline value submitted on February 21, 2024.
- SoCalGas is using leaker-based emission factors to estimate 2025 and 2030 Distribution Main and Service Pipeline Leak emissions. SoCalGas is utilizing the same emission factors that were submitted in the 2023 Annual Emissions Report to estimate emissions for Chapters 1, 2, and 4. SoCalGas is using the emission factors that were submitted in the "SoCalGas and SDG&E 2022 Aerial Methane Mapping Research & Cost-Effectiveness Summary Report" from February 2023 to estimate emissions for Chapter 14.
- Per the guidance provided during the 2024 Winter Workshop, SoCalGas is including leaks with emissions <10,000 ppm in the emission forecasting calculations for Chapter 24.
- The 2030 emissions reflect forecasted emission reductions as proposed in this Compliance Plan. The forecasted emission reductions are subtracted from the proposed 2015 baseline to estimate reductions relative to baseline.

Emission models used to forecast reductions will have some degree of variation and the final observed reduction may be higher or lower. Based on information and technologies currently available, SoCalGas is proposing to implement measures that maximize cost-effective emission reductions as reasonably as possible and then maintain the reduced emission levels through 2030 and beyond. As proposed research projects and pilots are completed, more accurate modeling may become available. In addition, as pilots are concluded, new technologies may become commercially available to further reduce emissions beyond what is currently forecasted.

In addition to the emissions forecasted to be reduced from SoCalGas's system, SoCalGas is proposing to use emerging technologies and data analytics to reduce post-meter (customer) emissions, further discussed in Chapter 14 (Aerial Monitoring). Although these reductions are not currently reflected in SoCalGas's Annual Emissions Report, these activities support the state's climate goals and the spirit of Senate Bill 1371.

Calculating Cost Effectiveness

SoCalGas implemented most cost-effective measures early on in the Emissions Strategy Program's (ESP) implementation to achieve the maximum emission reductions in the shortest period of time. Future initiatives may be less cost effective and hence demonstrate lower emissions reductions.

Historical Standard Cost Effectiveness:

$$\frac{(RRR - Cost\ Benefits)_{2018\text{-}2022}}{Emissions\ Reductions_{2018\text{-}2022}}$$

Pursuant to D.19-08-020, SoCalGas also calculates cost effectiveness with avoided Cap & Trade costs, and social cost of methane as follows:

Historical Cost Effectiveness with avoided Cap & Trade Costs:

$$\frac{(RRR - Cost\ Benefits - Avoided\ Cap\ \&\ Trade\ Costs)_{2018\text{-}2022}}{Emissions\ Reductions_{2018\text{-}2022}}$$

Historical Cost Effectiveness with avoided Social Cost of Methane and Cap & Trade Costs:

$$\frac{(RRR - Cost\ Benefits - Avoided\ Cap\ \&\ Trade\ Costs - Social\ Cost\ of\ Methane)_{2018\text{-}2022}}{Emissions\ Reductions_{2018\text{-}2022}}$$

Historical Cost Effectiveness with avoided Social Cost of Methane, Cap & Trade Costs, and Safety Benefit:

$$\frac{(RRR - Cost\ Benefits - Avoided\ Cap\ \&\ Trade\ Costs - Social\ Cost\ of\ Methane - Safety\ Benefit)_{2018\text{-}2022}}{Emissions\ Reductions_{2018\text{-}2022}}$$

Future Standard Cost Effectiveness:

$$\frac{(AARR - Cost\ Benefits)_{2025\text{-}2030}}{Emissions\ Reductions_{2025\text{-}2030}}$$

Pursuant to D.19-08-020, SoCalGas also calculates cost effectiveness with avoided Cap & Trade costs, and social cost of methane as follows:

Future Cost Effectiveness with avoided Cap & Trade Costs:

$$\frac{(AARR - Cost\ Benefits - Avoided\ Cap\ \&\ Trade\ Costs)_{2025\text{-}2030}}{Emissions\ Reductions_{2025\text{-}2030}}$$

Future Cost Effectiveness with avoided Social Cost of Methane and Cap & Trade Costs:

$$\frac{(AARR - Cost\ Benefits - Avoided\ Cap\ \&\ Trade\ Costs - Social\ Cost\ of\ Methane)_{2025\text{-}2030}}{Emissions\ Reductions_{2025\text{-}2030}}$$

Future Cost Effectiveness with avoided Social Cost of Methane, Cap & Trade Costs, and Safety Benefit:

$$\frac{(AARR - Cost\ Benefits - Avoided\ Cap\ \&\ Trade\ Costs - Social\ Cost\ of\ Methane - Safety\ Benefit)_{2025\text{-}2030}}{Emissions\ Reductions_{2025\text{-}2030}}$$

Common Assumptions for Cost Estimates

Below are the common assumptions SoCalGas made when building cost estimates for the measures described in this Compliance Plan:

1. AARR = Average annual revenue requirement, calculated by dividing the cumulative revenue requirement for each measure by the useful life of the measure or asset
2. RRR = Realized revenue requirement. It should be noted that AARR and RRR will not match up by definition. Using an "average" does not account for the "realized" due to actual timing of when costs hit and the magnitude and mix of O&M and capital spending. As such, the corresponding AARR and RRR will result in variances
3. Full-Time Equivalents (FTEs) are internal company employees whose costs are known as "Labor." The salary of these FTEs is assumed to be $100,000 in direct annual costs, unless noted otherwise. Contractors are included in "Non-Labor" costs
4. Vehicle costs for employees are included in the loaders for employees and, therefore, are not shown as a specific line item, unless noted otherwise
5. Cost estimates were created in December 2021 dollars and loaded with December 2021 loading factors. Actual loaders vary month to month and may generate a variability in actual spending
6. When measures benefit both SoCalGas and SDG&E, unless otherwise noted, the costs are split 91% SoCalGas and 9% SDG&E. This percentage split is based on the ratio of emissions reported by each utility, as reported in the 2016 Emissions Inventory (reported in 2017)
7. The cost benefit values utilized in the 2024 Compliance Plan are as follows:
    a. The social cost of methane is $24.42/MCF. Per written guidance from the CPUC Safety Policy Division on November 11, 2023, the calendar year 2020 social cost of methane from the 2022 Compliance Plan was adjusted for inflation using the California Consumer Price Index to arrive at the updated value.
    b. The cost benefit of the reduced cost of gas was evaluated at the forecasted average annual Weighted Average Cost of Gas (WACOG) published in the 2018 California Gas Report, converted to cost per MCF using a BTU conversion factor of 1.0343 MCF/MMBtu, resulting in a cost benefit of $2.42/MCF. This value was not updated from the 2022 Compliance Plan due to insufficient public data.
    c. Cap & Trade costs are $45.12/MTCO2e, assuming December 2025 vintage prices, based on a 5-day average of trading days January 2 – 8, 2024. This futures data was acquired from the International Exchange. Converting from MTCO2e to MCF using the methods of D.15-10-032 results in a cost benefit of $2.46/MCF
    d. Safety benefits were calculated using the following methods:

$$Benefits\ 1 = Hazardous\ Leaks\ Prevented\ or\ Repaired * P(SI|HL) * VSL$$

$$Benefits\ 2 = Non\ Haz\ Leaks\ Prevented\ or\ Repaired * P(Non\ Haz\ becomes\ Haz) * P(SI|HL) * VSL$$

        i. P(SI|HL) represents the probability that a hazardous leak results in a serious incident
        ii. P(Non Haz becomes Haz) represents the probability that a non-hazardous leak becomes a hazardous leak

iii. The probability that a hazardous leak results in a serious incident was estimated using publicly available data from PHMSA
iv. The probability that a non hazardous leak becomes hazardous was estimated using internal SoCalGas Company data
v. The number of hazardous and non-hazardous leaks prevented or repaired by each emission reduction program were estimated using historical data and future projections
vi. VSL's were calculated using the valuation of statistical life information from page 60 of the Risk-Based Decision-Making Framework (D.22.12.027) and publicly available incident data from PHMSA. The valuations from D.22.12.027 and the PHMSA incident data were used to calculate an average valuation per incident

8. Loaded chapter costs include a 10% contingency, as noted in the SoCalGas Advice Letter and each chapter cost summary section

SoCalGas Table of Concordance

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SoCalGas Attachment Library

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SoCalGas Acronym Library

Acronym	Definition
49 CFR 192	PHMSA Regulation - Transportation Of Natural And Other Gas By Pipeline: Minimum Federal Safety Standards
811	National call-before-you-dig phone number
AARR	Average annual revenue requirement
ACOR	Atmospheric Corrosion
AG	Above Ground
AL	Advice Letter
AMD	Advanced Meter Detection
AMI	Advanced Meter Initiative
AMM	Aerial Methane Mapping/ Aerial Monitoring
AOC	Abnormal Operating Conditions
API	American Petroleum Institute
BP	Best Practice
BTU	British thermal unit
CalGEM	California Geological Energy Management Division
CARB	California Air Resources Board
CCSLB	California Contractor State License Board
CF	Cubic feet
CFH	Cubic feet per hour
CIS	Customer Information System
CPDR	Company Property Damage Report
CPUC	California Public Utilities Commission
CT	Construction Technician
DIMP	Distribution Integrity Management Program
DM&S	Distribution Main and Services
DP	Differential Pressure
DPIR	Detecto Pak-Infrared
EDAPO	Engineering Data Analytics and Performance Optimization
EF	Emission Factor
EPA	Environmental Protection Agency
FTE	Full Time Equivalent; Employee
G.O. 112F	State General Order Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems
GIS	Geographic Information System

Acronym	Definition
GML	Gas Mapping LiDAR™
GRC	General Rate Case
GS	Gas Standard
HB	High Bleed
HESD	Historizing Emission Sensor Data
LDAR	Leak Detection and Repair
LiDAR	Light Detection and Ranging
LNG	Liquified Natural Gas
M&I	Maintenance and Inspection
M&R	Measurement and Regulation
MCF	Thousand cubic feet
MDMS	Meter Data Management system
MMBtu	Million British thermal units
MSCF/MCF	Thousand standard cubic feet
MSP	Material Specification Properties
MTCO2e	Metric tons of Carbon Dioxide equivalent
MTU	Meter transmission unit
N/A	Not Applicable
NGLAP	Natural Gas Leak Abatement Program
NSOTA	Non-State-of-the-Art
O&M	Operations & Maintenance
PAPA	Pipeline Associations for Public Awareness
PHMSA	Pipeline and Hazardous Materials Safety Administration
PMC	Planned Meter Change
psig	Pounds per square inch
QA	Quality assurance
QC	Quality Control
R/V	Read/Verify
RD&D	Research, Development, & Demonstration
RMLD	Remote Methane Leak Detector
RRR	Realized Revenue Requirement
SAP	System Analysis Program
SCF	Standard cubic feet
SED	Safety and Enforcement Division
SIMP	Storage Integrity Management Program

Acronym	Definition
SOTA	State-of-the-Art
WACOG	Weighted Average Cost of Gas
ZEVAC	Zero Emission Vacuum and Compressor

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 15: Distribution Leak Surveys
Utilities should conduct leak surveys of the gas distribution system every three (3) years, not to exceed 39 months, in areas where General Order (G.O.) 112-F, or its successors, requires surveying every five (5) years. In lieu of a system-wide three-year leak survey cycle, utilities may propose and justify in their Compliance Plan filings, subject to Commission approval, a risk-assessment based, more cost-effective methodology for conducting gas distribution pipeline leak surveys at a less frequent interval. However, utilities shall always meet the minimum requirements of G.O. 112-F, and its successors.
Best Practice 16: Special Leak Surveys
Utilities shall conduct special leak surveys, possibly at a more frequent interval than required by G.O. 112-F (or its successors) or BP 15, for specific areas of their transmission and distribution pipeline systems with known risks for natural gas leakage. Special leak surveys may focus on specific pipeline materials known to be susceptible to leaks or other known pipeline integrity risks, such as geological conditions. Special leak surveys shall be coordinated with transmission and distribution integrity management programs (TIMP/DIMP) and other utility safety programs. Utilities shall file in their Compliance Plan proposed special leak surveys for known risks and proposed methodologies for identifying additional special leak surveys based on risk assessments (including predictive and/or historical trends analysis). As surveys are conducted over time, utilities shall report as part of their Compliance Plans, details about leakage trends. Predictive analysis may be defined differently for differing companies based on company size and trends.
Best Practice 20a: Quantification
Utilities shall develop methodologies for improved quantification, geographic evaluation, and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together, with CPUC and ARB staff, to come to an agreement on a similar methodology to improve emissions quantification of leaks to assist the demonstration of actual emission reductions.
Best Practice 21: Find It, Fix It
Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event, more than three (3) years after discovery. Utilities may make reasonable exceptions for leaks that are costly to repair relative to the estimated size of the leak.

Historic Project Achievements:

Over the years, SoCalGas accumulated an inventory of non-hazardous leaks. Prior to the SB 1371 Natural Gas Leakage Abatement Rulemaking (R.)15-01-008, SoCalGas made efforts to reduce its inventory. In 2017, SoCalGas created a project team that focused on leak inventory reduction efforts and hired leakage-focused crews to gain efficiency through leak repair repetition. The project team tracked the costs of leak repairs, field crew productivity, and communicated the leak inventory efforts to municipalities for awareness. The reduction effort was further carried out by prioritizing and performing replacements on main and service segments identified to have both historical leakage and multiple leaks repaired. Additionally, this effort focused on repairing leaks based on detection year and targeted the oldest leaks first. This program has repaired leaks in advance of required timeframes to meet safety standards prescribed in 49 CFR Part 192.

In 2020, SoCalGas reduced its inventory to a milestone of 32 months and focused on a new goal of reducing its inventory for Code 3 steel leaks to 24 months by December 31, 2021. These efforts involved 88 dedicated employees working extensively to obtain permits, conduct planning, and determine schedules. In 2022, SoCalGas continued its effort to reduce methane emissions by eliminating non-hazardous leaks older than 13 months.

At the time of preparing this Compliance Plan, SoCalGas is repairing non-hazardous leaks within the year detected with an average repair time of eight (8) months for 2023. The method to keep track of average repair time is in line with the Annual Emissions Report submittal to the Commission. Previously, the average time to repair a leak in 2020, 2021, and 2022 was 21, 13, and 11 months, respectively.

There are some situations where non-hazardous leaks are exceptionally costly or complex to repair due to permitting, size, scope of main alterations/replacements for certain leaks, right-of-way issues, and/or city street moratoriums. Pursuant to Decision (D.) 17-06-015 and Best Practice (BP) 21, SoCalGas makes reasonable exceptions for these certain repairs that might not meet the reduction goal due to the circumstances described in this paragraph.

Emission Reductions Achieved:

The estimated annual emissions were calculated using the emission factors from Appendix 4 of the 2023 Annual Emissions Report. Emission reductions were calculated by subtracting the estimated annual Distribution Main and Service Line leak emissions from the approved 2015 baseline of 576,261 MCF.

Historical Emission Reductions (MCF)

2018	2019	2020	2021	2022
N/A	N/A	7,208	70,022	156,406

Cost Effectiveness Evaluation on Historic Work:

The 2018 – 2020 cost effectiveness was higher than forecasted in the 2020 Compliance Plan due to: one (1) upfront cost for this program, and two (2) a longer project ramp up period. The costs for leak inventory repair were front loaded, such as vehicles for the crews, new tools, hiring costs, and training of the new field personnel. In early 2021, Distribution Operations focused on repairing leaks to reduce its methane emissions compared to the initial two (2) years of the 2018 Compliance Plan, which focused more on implementation. Moving forward, leak mitigation will focus on all Code 2 and 3 leaks. The cost effectiveness for this effort has decreased and will continue to do so over time. The initial investment is spread out over multiple years and the forecasted emission reductions are expected to increase from 2021 – 2030. Additionally, the total emissions reductions achieved from leak inventory reduction efforts are larger than the figure used in the below cost effectiveness calculation due to separate leak inventory reduction efforts from programs such as Distribution Integrity Management Program (DIMP).

Historical Standard Cost Effectiveness ($/MCF)

Projected in 2022 Compliance Plan	Actual Cost Effectiveness (2018-2022)
$74	$394

Part 2. Proposed New or Continuing Measure

SoCalGas will continue to accelerate leak repair for its Code 2 and 3 leaks. If all non-hazardous leaks are repaired within the year detected with an average eight (8)-month repair time frame in 2024, SoCalGas will seek to repair all non-hazardous leaks within seven (7) months of detection in 2025 and six (6) months of detection by the end of 2026.

In addition to the leak inventory reduction, SoCalGas proposes to continue funding leak repairs on all leaks detected due to increased leak survey and Aerial Methane Mapping (AMM), as discussed in the AMM and Increased Leak Survey chapters. The cost for this work can be found in those chapters.

SoCalGas anticipates upward pressures in cost due to the Department of Transportation's (DOT) Pipeline Hazardous Materials Safety Administration (PHMSA) proposed legislation to further reduce emissions by mandating leak repairs on an accelerated schedule. SoCalGas will be required to complete more leak repairs and more paving each year. Despite these upward pressures, SoCalGas will continue to achieve emission reduction goals by utilizing its existing workforce. SoCalGas will also continue to implement best management practices to ensure leak repairs are conducted safely, and costs are minimized wherever possible. Finally, in 2022, SoCalGas created the City Notification Department (CND) which has successfully obtained blanket leak repair permits from 157 of the 238 cities SoCalGas serves (66%), exceeding the goal of 25%. These permits significantly streamline leak repair timeframes. Due to its success SoCalGas will continue the CND program and pursue permits from the remaining cities.

<u>Project Milestones:</u>

- Updated Gas Standard with 24-month repair timeframe requirement (Q1 of 2022).
- Achieved 13-month age of leak inventory (Q4 of 2022).
- Achieved 12-month age of leak inventory (Q4 of 2023).
- Repair leaks within year detected with an average repair time of eight (8) months (estimated by Q4 of 2024).
- Repair leaks within eight (8) months of detection with an average repair time of six (6) months (estimated by Q4 of 2025).
- Repair leaks within six (6) months of detection (estimated by Q4 of 2026).

Part 3. Abatement Estimates

SoCalGas estimates that the total emission reductions achieved by repairing leaks within seven (7) months of detection in 2025 and six (6) months in 2026 will be 524,320 MCF relative to the 2015 baseline. The incremental reductions forecasted during the 2024 Compliance Plan period by reducing the non-hazardous leaks within seven (7) months of detection are estimated at 257,399 MCF and from seven (7) months to six (6) months are estimated at 266,921 MCF. In addition, the Large Leak Prioritization (LLP) process can be attributed to 13% of the accelerated leak repair, resulting from the Decision Tree method as described in Chapter 4. The emission reductions from LLP are included in each column of the table below. These emission reductions will be demonstrated in the Distribution Mains & Services System Category in Appendix 4 of the Annual Emissions Report.

The emission reductions estimates were forecasted by applying shorter leak repair timeframes to the Appendix 4 Distribution Main and Service Line leak data from the 2023 Annual Emissions Report.

Forecast of Emission Reductions from Baseline (MCF)

2025	2026	2027	2028	2029	2030
257,399	266,921	266,921	266,921	266,921	266,921

Part 4. Cost Estimates

O&M Cost Estimates			
Activity	2025	2026	2025-2026
	Direct	Direct	Total Loaded O&M with Contingency
Leak Repair	$25,700,000	$25,700,000	$88,330,000
Program Management Office	$500,000	$500,000	$2,200,000
Field Inspector	$200,000	$500,000	$880,000
Work Oder Control	$500,000	$400,000	$2,200,000
Administrative Resource Scheduling Operations	$400,000	$400,000	$1,760,000
Paving Department	$500,000	$500,000	$2,200,000
Permit Team (CND)	$681,818	$681,818	$3,000,000
Total	**$26,631,818**	**$26,631,818**	**$100,570,000**

Capital Cost Estimates			
Activity	2025	2026	2025-2026
	Direct	Direct	Total Loaded Capital with Contingency
Leak Service Replacements	$9,650,000	$9,650,000	$30,580,000
Leak Main Replacements	$8,500,000	$8,500,000	$24,530,000
Total	**$17,500,000**	**$17,500,000**	**$55,110,000**

Total Revenue Requirement over Expected Life of Investment
$190.5 million
Average Annual Revenue Requirement
$52.3 million

Cost Assumptions:

- Assuming 8,500-9000 leaks repaired per year.
- Average O&M leak repair cost is $6,600 per leak.
- Average service replacement cost is $10,000.
- Average main replacement cost is $90,000.
- 83% of leaks can be repaired via leak repair methods.
- 16% of leaks will require a service replacement.
- 1% of leaks will require a main replacement.
- Estimated costs for leak repairs are inclusive of incremental Code 1, 2, 3, and above ground leaks detected due to incremental survey as discussed in Chapter 14.
- Estimated cost for leak repairs is inclusive of incremental large Code 1 and 2 leaks identified through LLP as discussed in Chapter 4.

Part 5. Cost Effectiveness/Benefits

The historical achieved cost effectiveness below is higher than forecasted for numerous reasons, as discussed in Part 1.

Historical Achieved Cost Effectiveness Calculations (2018-2022) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits	With Cap and Trade, Social Cost of Methane, and Safety Cost Benefits
$394	$392	$367	$367

Forecast of Cost Effectiveness Calculations (2025-2030) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits	With Cap and Trade, Social Cost of Methane, and Safety Cost Benefits
$190	$187	$163	162

Part 6. Supplemental Information/Documentation

Attachment 1A: Historical Project Schedule for Leak Inventory Reduction

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 15: Gas Distribution Leak Surveys
Utilities should conduct leak surveys of the gas distribution system every 3 years, not to exceed 39 months, in areas where General Order (G.O.) 112-F, or its successors, requires surveying every 5 years. In lieu of a system-wide three-year leak survey cycle, utilities may propose and justify in their Compliance Plan filings, subject to Commission approval, a risk-assessment based, more cost-effective methodology for conducting gas distribution pipeline leak surveys at a less frequent interval. However, utilities shall always meet the minimum requirements of G.O. 112-F, and its successors.
Best Practice 16: Special Leak Surveys
Utilities shall conduct special leak surveys, possibly at a more frequent interval than required by G.O. 112-F (or its successors) or BP 15, for specific areas of their transmission and distribution pipeline systems with known risks for natural gas leakage. Special leak surveys may focus on specific pipeline materials known to be susceptible to leaks or other known pipeline integrity risks, such as geological conditions. Special leak surveys shall be coordinated with transmission and distribution integrity management programs (TIMP/DIMP) and other utility safety programs. Utilities shall file in their Compliance Plan proposed special leak surveys for known risks and proposed methodologies for identifying additional special leak surveys based on risk assessments (including predictive and/or historical trends analysis). As surveys are conducted over time, utilities shall report as part of their Compliance Plans, details about leakage trends. Predictive analysis may be defined differently for differing companies based on company size and trends.

Historic Project Achievements:

Leak surveys on distribution lines have historically been performed for safety reasons according to the requirements under 49 CFR § 192.723. SoCalGas pipelines are typically leak surveyed at intervals of one (1), three (3), or five (5) years. The frequency of this survey is determined by the pipe material involved, i.e., plastic or steel, the operating pressure, whether the pipe is under cathodic protection, and the proximity of the pipe to various population densities. In 2018, SoCalGas increased the survey frequency for all Non-State-of-the-Art (NSOTA) pipe from 5-year to annual. This activity was funded by the DIMP. In 2020, SoCalGas' Gas Standard 223.0100, *Leakage Surveys* was updated to reflect the annual survey cycles for unprotected steel and NSOTA pipe.

Increasing leak survey for unprotected steel and NSOTA pipe resulted in fluctuations in monthly leak survey footage. To correct this issue, SoCalGas created a plan in 2019 to survey additional lines to reset the survey anniversary date and levelize the footage of survey performed each month to maintain a level workforce throughout the year. The effort to levelize the survey maps was completed in Q1 of 2021 for all unprotected steel, and the effort to levelize NSOTA pipe will continue through 2025.

SoCalGas continues to maintain the accelerated leak survey efforts for unprotected steel pipe. Since the accelerated survey's inception in 2020, the number of leaks detected has decreased. The work is being completed with the existing personnel, tools, and equipment purchased in the 2018 Compliance period.

Emission Reductions Achieved:

Historical Emission Reductions (MCF)

2018	2019	2020	2021	2022
45,985	67,399	150,578	149,460	149,460

The portion of emissions associated with NSOTA pipe in the 2015 baseline for Distribution Main and Services was 111,540 MCF. Emission reductions achieved in 2018 after one (1) year of annual survey performed on NSOTA pipe was 45,985 MCF. The emission reductions for NSOTA pipe in 2019 was 67,399 MCF. The total emission reductions for NSOTA pipe and unprotected steel for 2020 was 150,578 MCF.

Cost Effectiveness Evaluation on Historic Work:

Historical Standard Cost Effectiveness ($/MCF)

Projected in 2022 Compliance Plan	Actual Cost Effectiveness (2018-2022)
$28	$21

Regarding the annual survey of NSOTA pipe, no costs were recorded to this program because this effort was funded through DIMP.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to continue performing annual leak survey on unprotected steel and NSOTA pipe in a continued effort to reduce methane emissions. For this Compliance Plan, SoCalGas is not reducing its leak survey beyond the 1- and 5-year current cycles. An analysis was done in the 2020 Compliance Period on switching from a 5-year to a 3-year cycle. The results showed that the cost and the emission reductions were not beneficial to have the survey cycles adjusted. Due to the shift of accelerated survey on unprotected steel, a subset of leaks is being repaired through this chapter. The dollars for those leaks are being requested in the cost summary table below.

The activities proposed in this measure have been achieved with the existing project management team, leak surveyors, field supervisors, leakage clerks, and planning associates that were hired to meet the requirements of the 2018 Compliance Plan. No additional personnel will be required for the continued efforts of increased leak survey and leak levelization.

Per the Reporting Year 2023 Annual Emissions Report, MSA (Meter Set Assembly) emissions make up approximately 33% of emission sources when compared to other emission source categories. SoCalGas proposes to expand its original 2022 Compliance Plan pilot study to examine MSA leaker-based emissions. The expanded pilot will be implemented during MSA surveys using portable infrared gas leak detectors to survey customer meters as part of corrosion surveys. Currently, MSAs are surveyed during pipeline surveys every one (1) and five (5) years using a DPIR. The proposed pilot will utilize the customer service field Energy Technicians Residential (ETRs) to randomly survey MSAs annually during surveys of other equipment. The data will be used to quantify potential emission reductions associated with detecting MSA leaks during this incremental survey practice.

SoCalGas will continue the ongoing efforts to execute the Field Data Quality Improvement (FDQI) project. No incremental dollars will be requested because the program will continue through this Compliance period.

Project Milestones:

- Shifting unprotected steel from 3-year to 1-year: By Q4 of 2020.
- Levelized unprotected steel: By Q1 of 2021.
- Implementation of Company-Specific Emission Factors testing: By Q4 of 2024.
- Levelized NSOTA pipe: By Q4 of 2025.
- FDQI Project: By Q4 of 2026.
- MSA Pilot Program: By Q4 of 2026.

Part 3. Abatement Estimates

SoCalGas estimates that the emission reductions achieved by continuing annual leak survey cycles on unprotected steel and NSOTA pipe and using Detecto Pak-Infrared (DPIRs) to survey MSAs will result in a total emission reduction of 230,230 MCF annually. These emissions will be reduced from the Pipeline Leaks Emission Source Category within the Distribution Mains and Services System Category and the Meter Leaks Emission Source Category within the Customer Meters Category. Because unprotected steel and NSOTA pipe have been shifted to annual leak survey cycles, the number of unknown leaks from these material types has been reduced to zero. All known leaks are subject to leak inventory reduction policies.

Emission reduction estimates were completed using leak data from the Pipeline Leaks Emission Source Category within the Distribution Mains and Services System Category of the Emission Year 2015 and 2022 Annual Emissions Reports. The emission factor of 0.1154 MCF/day from the Emission Year 2022 report was applied to the 2015 data to provide an apples-to-apples comparison. The volume of emissions from unknown leaks on Vintage Plastic and Unprotected Steel during the baseline year was subtracted from the volume emitted from unknown leaks on these material types during 2022. This difference represents the reduction in emissions that was caused by increasing survey cycles on Vintage Plastic and Unprotected Steel. Because there are currently no plans to further modify main and service survey cycles, it is assumed that the reductions observed during 2022 will be maintained in subsequent years. The emissions reductions in the table below represent the savings achieved by accelerating NSOTA and unprotected steel survey cycles to 1-year.

Forecast of Emission Reductions from Baseline (MCF)

2025	2026	2027	2028	2029	2030
149,460	149,460	149,460	149,460	149,460	149,460

***Note: Forecasted reductions do not include reductions from the MSA Pilot study**

Calculation Methodology:

The calculations used to estimate the emission reductions were completed by applying the following methodology used to estimate emissions from the distribution system in the Annual Emissions Report:

- Derive the annual emission volumes from unknown leaks for Emission Year 2015 and 2022.
- Calculate the difference in emissions from unknown leaks on NSOTA and unprotected steel during Emission Year 2015 relative to 2022.

This methodology is based on the following assumptions:

- The number of unknown leaks is assumed to be zero after leak survey cycles are accelerated to 1-year timeframes because there are no un-surveyed areas during a given year.
- The current survey cycles are held constant from Emission Year 2022 through 2030.
- Estimated emission reductions associated with MSA leaks are calculated by increasing the frequency of survey to 3-year (ACOR survey cycle) and adjusting for the estimated number of new leaks detected. This process would increase the number of leaks detected annually but reduce the number of unknown leaks and non-detected leaks, resulting in a net reduction in system emissions.

Part 4. Cost Estimates

Cost estimates below include only costs associated with annual survey cycles on un-protected steel.

O&M Cost Estimates			
Activity	**2025**	**2026**	**2025-2026**
	Direct	**Direct**	**Total Loaded O&M Cost with Contingency**
Leak Survey Field Employees	$1,186,000	$1,186,000	$5,186,720
Leak Survey Supervisors	$204,800	$204,800	$896,368
QA Employees	$223,600	-	$976,712
Map Levelization Effort	$343,600	-	$736,120
Increased Leak Survey Incremental Repair	$1,100,000	$1,100,000	$4,048,000
FDQI Program	$1,479,091	$1,828,182	$7,332,183
MSA Survey Pilot Study/Training	$500,000	$600,000	$2,439,360
Total	**$5,037,091**	**$4,918,982**	**$21,615,463**

Capital Cost Estimates			
Activity	**2025**	**2026**	**2025-2026**
	Direct	**Direct**	**Total Loaded Capital Cost with Contingency**
10 Portable Infrared Gas Detectors (Pilot Program)	$ 100,000	-	$ 220,000
Total	**$ 100,000**	**-**	**$ 220,000**

Total Revenue Requirement over Expected Life of Investment
$22.3 million
Average Annual Revenue Requirement
$11.0 million

Cost Assumptions:

- 6,114 feet surveyed per day per full-time equivalent (FTE).
- Represented Employee Hourly Rate: $42.00.
- 13 Leak Survey Field FTEs.
- Three (3) Survey Supervisors.
- Two (2) Quality Assurance FTEs.
- 15 ETDs (FDQI Project).
- Two (2) Project Managers (FDQI Project).
- Three (3) Tech Advisors (FDQI Project).
- One (1) PPA (FDQI Project).
- One (1) Lead Planner (FDQI Project).
- One (1) GIS Specialist (FDQI Project).
- $100K annual salary for Supervisors and QA employees.
- 10% contingency is included in the total loaded costs.

Part 5. Cost Effectiveness/Benefits

Historical Achieved Cost Effectiveness Calculations (2018-2022) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits	With Cap and Trade, Social Cost of Methane, and Safety Cost Benefits
$21	$18	-$6	-$6

Forecast of Cost Effectiveness Calculations (2025-2030) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits	With Cap and Trade, Social Cost of Methane, and Safety Cost Benefits
$71	$68	$44	$44

Part 6. Supplemental Information/Documentation

Attachment 2A: Historical Project Schedule for Increased Leak Survey

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 23: Minimize Emissions from Operations, Maintenance and Other Activities
Utilities shall minimize emissions from operations, maintenance, and other activities, such as new construction or replacement, in the gas distribution, transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e. no-bleed) or vents significantly less natural gas (i.e. low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.
Best Practice 3: Pressure Reduction Policy
Written company policy stating that pressure reduction to the lowest operationally feasible level in order to minimize methane emissions is required before non-emergency venting of high-pressure distribution (above 60 psig), transmission, underground storage infrastructure consistent with safe operations and considering alternative potential sources of supply to reliably serve customers.
Best Practice 4: Project Scheduling Policy
Written company policy stating that any high-pressure distribution (above 60 psig), transmission or underground storage infrastructure project that requires evacuating methane will build time into the project schedule to minimize methane emissions to the atmosphere consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Projected schedules of high-pressure distribution (above 60 psig), transmission or underground storage infrastructure work, requiring methane evacuation, shall also be submitted to facilitate audits, with line venting schedule updates TBD.
Best Practice 5: Methane Evacuation Procedures
Written company procedures implementing the BPs approved for use to evacuate methane for non-emergency venting of high-pressure distribution (above 60 psig), transmission or underground storage infrastructure, how to use them consistent with safe operations and considering alternative potential sources of supply to reliably serve customers.
Best Practice 6: Methane Evacuation Work Orders Policy
Written company policy that requires that for any high-pressure distribution (above 60 psig), transmission or underground storage infrastructure projects requiring evacuating methane, Work Planners shall clearly delineate, in procedural documents, such as work orders used in the field, the steps required to safely and efficiently reduce the pressure in the lines, prior to lines being vented, considering alternative potential sources of supply to reliably serve customers.
Best Practice 7: Bundling Work Policy
Written company policy requiring bundling of work, whenever practicable, to prevent multiple venting of the same piping consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Company policy shall define situations where work bundling is not practicable.

Historic Project Achievements:

SoCalGas has documented use of cost-effective methods to reduce vented emissions during high-pressure construction projects, including performing pressure reduction using mobile compressors, transferring gas to lower pressure systems, and isolating smaller sections of pipe using stopples.

Operators of natural gas pipeline systems routinely reduce line pressure and discharge gas from pipeline sections to provide safe working conditions during maintenance and repair activities. In the 2022 Compliance Plan, SoCalGas was approved to continue blowdown reduction efforts and to increase the resources to support blowdown gas capture activities. This included purchasing compressors and cross-compression equipment to reduce blowdown emissions, increasing field operations staff to support the incremental time required to reduce blowdown, creating a record keeping and compliance process to document that the requirements of the Best Practices are being met. Seventeen incremental full-time equivalents (FTEs) were required at SoCalGas for this implementation.

In addition to staffing efforts, in October 2021 SoCalGas published a Gas Standard 223.0155, *Planning Pipeline Blowdowns and Reporting* to outline the methods of blowdown reduction and provide resources to Planners and Project Managers when planning pipeline blowdowns and the associated blowdown reductions.

Emission Reductions Achieved:

The 2015 baseline for blowdown emissions reported for Blowdowns in Transmission Pipelines, Transmission Measurement and Regulation (M&R) Stations, Distribution Mains & Service Pipelines, Distribution Measurement and Regulation (M&R) Stations totaled 204,987 MCF. Emissions from these categories in the calendar years 2018, 2019, 2020, 2021, and 2022 totaled 167,212 MCF, 134,793 MCF, 76,352 MCF, 13,335 MCF, and 21,478 MCF respectively. This equates to an estimated reduction of 37,775 MCF for 2018, 70,194 MCF for 2019, 128,635 MCF for 2020, 191,652 MCF for 2021, and 183,509 MCF for 2022.

Historical Emission Reductions (MCF)

2018	2019	2020	2021	2022
37,775	70,194	128,635	191,652	183,509

Emission reductions have increased each year; however, they decreased from 2021 to 2022. This is due to stronger emission reductions criteria for each blowdown activity project which minimizes gas being blown down to atmosphere, although there was an increase in blowdown projects. The emission reductions achieved in 2023 are expected to be in line with, or greater than, the 2022 emissions but cannot be evaluated and are pending submittal of the 2023 Annual Emissions Report. Similarly, SoCalGas anticipates achieving greater reductions in 2024.

Cost Effectiveness Evaluation on Historic Work:

Historical Standard Cost Effectiveness ($/MCF)

Projected in 2022 Compliance Plan	Actual Cost Effectiveness (2018-2022)
$41	$33

Pipeline Blowdown Reduction Activities have proven to be more cost-effective than originally anticipated. This can be attributed to updated standards and practices in the company, faster than anticipated adoption of blowdown reduction activities across the company, and the effectiveness of the centralized department specializing in blowdown reduction execution.

Part 2. Proposed New or Continuing Measure

SoCalGas will continue high-pressure pipeline blowdown reduction efforts. SoCalGas will continue to bundle work on high-pressure lines when and where it is practical to do so. SoCalGas proposes to install a new drawdown infrastructure at an operating facility. Drawdown is a process to reduce pipeline pressure without utilizing gas capture or cross compression equipment. This new infrastructure will allow SoCalGas to drawdown multiple high-pressure pipelines to lower pressures when and where it is practical to do so. The new infrastructure will improve the facility's operations, decrease the need to utilize high powered cross compression equipment, and reduce the volume of emissions released to the atmosphere.

Continuing work includes maintaining the blowdown reduction program to include gas capture on more projects, the use of cross compression, and installing fittings on valves to expand cross compression capabilities.

Part 3. Abatement Estimates

SoCalGas estimates that the emission reductions achieved by increasing blowdown reduction activities will result in a total emission reduction of 191,775 MCF from the 2015 baseline of 204,987 MCF. These emissions will be reduced from the Blowdown Emission Source Category within the Transmission Pipeline, Transmission M&R Stations, Distribution Mains & Services, and Distribution M&R Station Categories.

Forecast of Emission Reductions from Baseline (MCF)

2025	2026	2027	2028	2029	2030
187,581	187,581	187,581	187,581	187,581	187,581

Blowdown emissions are a function of activity level. This is assuming the activity level remains constant and there are no unforeseen emergency blowdowns. From 2025 to 2030, the forecasted emission was derived from the average historical emission reductions from the 2021 and 2022. SoCalGas will continue evaluating opportunities to expand on blowdown reduction capabilities, and emerging technologies may allow for further reductions in future Compliance periods that cannot be forecasted.

Part 4. Cost Estimates

O&M Cost Estimates			
Activity	**2025**	**2026**	**2025 – 2026**
	Direct	**Direct**	**Total Loaded O&M Cost with Contingency**
Blowdown Reduction Central Organization	$1,092,250	$1,092,250	$3,998,060
Transmission Operations Staff	$589,515	$589,515	$2,451,307
Blowdown Reduction Projects	$931,888	$943,537	$2,742,081
Total	**$2,613,653**	**$2,625,302**	**$9,191,448**

Capital Cost Estimates			
Activity	**2025**	**2026**	**2025 - 2026**
	Direct	**Direct**	**Total Loaded Capital Cost with Contingency**
Blowdown Reduction Projects	$8,334,900	$8,751,645	$24,903,639
Drawdown Infrastructure Project	$1,365,387	$5,705,819	$9,082,934
Total	**$9,700,287**	**$14,457,464**	**$33,986,573**

Total Revenue Requirement over Expected Life of Investment
$110.8 million
Average Annual Revenue Requirement
$6.2 million

Cost Assumptions:

- Annual cost of $115,000 per management FTE.
- Average rate of $41.47 per field FTE.
- Centralized organization (all management employees).
    - 17 FTEs for 2025 and 2026.
- Transmission Operations.
    - Two (2) Supervisors (Management).
    - Three (3) Field Employees.

Part 5. Cost Effectiveness/Benefits

Historical Achieved Cost Effectiveness Calculations (2018-2022) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits
$33	$30	$6

Forecast of Cost Effectiveness Calculations (2025-2030) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits
$22	$20	-$4

Part 6. Supplemental Information/Documentation

Attachment 3A: Historical Project Schedule Blowdown Reduction Activities

Attachment 3B: Historical Project Schedule Blowdown Reduction Planning tool

2024 SB 1371 Compliance Plan
Chapter 4: Large Leak Prioritization

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 15: Gas Distribution Leak Surveys
Utilities should conduct leak surveys of the gas distribution system every 3 years, not to exceed 39 months, in areas where General Order (G.O.) 112-F, or its successors, requires surveying every 5 years. In lieu of a system-wide three-year leak survey cycle, utilities may propose and justify in their Compliance Plan filings, subject to Commission approval, a risk-assessment based, more cost-effective methodology for conducting gas distribution pipeline leak surveys at a less frequent interval. However, utilities shall always meet the minimum requirements of G.O. 112-F, and its successors.
Best Practice 16: Special Leak Surveys
Utilities shall conduct special leak surveys, possibly at a more frequent interval than required by G.O. 112-F (or its successors) or BP 15, for specific areas of their transmission and distribution pipeline systems with known risks for natural gas leakage. Special leak surveys may focus on specific pipeline materials known to be susceptible to leaks or other known pipeline integrity risks, such as geological conditions. Special leak surveys shall be coordinated with transmission and distribution integrity management programs (TIMP/DIMP) and other utility safety programs. Utilities shall file in their Compliance Plan proposed special leak surveys for known risks and proposed methodologies for identifying additional special leak surveys based on risk assessments (including predictive and/or historical trends analysis). As surveys are conducted over time, utilities shall report as part of their Compliance Plans, details about leakage trends. Predictive analysis may be defined differently for differing companies based on company size and trends.
Best Practice 20a: Quantification
Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together with CPUC and ARB staff to come to an agreement on a similar methodology to improve emissions quantification of leaks to assist the demonstration of actual emission reductions.
Best Practice 21: Find It, Fix It
Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event, more than 3 years after discovery. Utilities may make reasonable exceptions for leaks that are costly to repair relative to the estimated size of the leak.

Historic Project Achievements:

SoCalGas has historically repaired leaks based on safety risk and has coded leaks as grades 1, 2, or 3 based on proximity to buildings, population density, and concentration of the leak. In the past, leak repair prioritization was solely based on safety and there was no correlation with emission volumes.

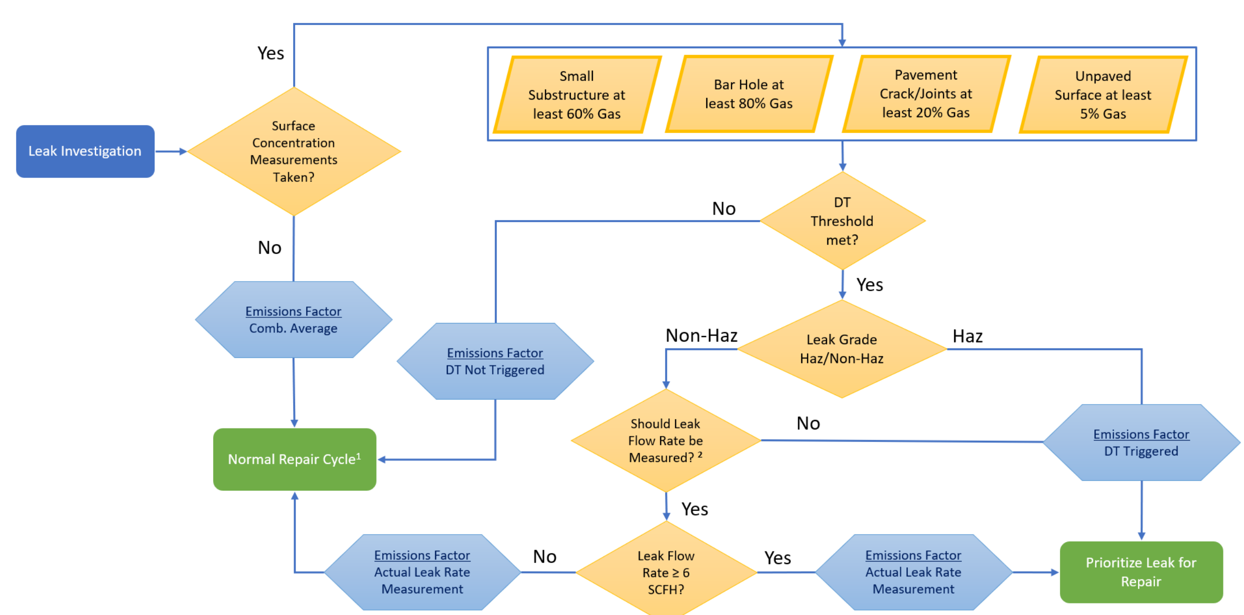
In the 2018 Compliance Plan, SoCalGas was approved to develop a method to differentiate leak locations with potentially larger leak rates and to conduct leak quantification resulting in repairs prioritized by leak rate.

In 2019, SoCalGas developed a decision tree methodology to identify and prioritize Code 2 and Code 3 leaks using surface expression measurements and implemented this program in three (3) Gas Distribution Service Districts using surface expression measurements to prioritize potentially large leaks for accelerated repair. Expedited leak repair was performed by the leakage personnel hired to support incremental leak repair for emission reduction, as outlined in Chapter 1.

During the Decision Tree Pilot Study, data showed that approximately 15% of leaks that met the Decision Tree threshold required measurement. Of the leaks that required measurement, approximately 13% were identified as "large leaks," or roughly 2% of all detected leaks. At the time of the pilot study, the threshold for a leak to be considered large is a flux rate greater than or equal to 10 CFH.

Based on the results of the 2021 Emission Factor Pilot Study Report, where emission flux rates were measured on 195 leaks, the average emission rate for large leaks is estimated at 8.29 CFH. Leaks that did not meet the decision tree threshold have an estimated emission rate of 2.10 CFH, and leaks where the decision tree process cannot be applied have an estimated emission rate of 4.52 CFH. SoCalGas will consider large leak cutoff points of 10 SCFH for all leaks that meet the decision tree and 6 CFH for all quantified leaks. All large leaks are prioritized for repair as soon as logistically possible within three (3) months of detection. The updated decision tree is shown below:

Figure 1. The Leak Investigation Decision Tree



[1]The normal repair cycle is based on leak grade (e.g., Haz leaks are repaired immediately, Non-Haz leaks are currently repaired within three years)

[2]The need for flow rate data is dependent on local operations' ability to accelerate the leak repair without a flow rate measurement. Measurement of leak flow rate is also dependent on operational issues; such as outskirt areas not resourced to perform leak flow rate measurements; Insufficient time prior to repair; and accessibility issues.

Emission Reductions Achieved:

Historical Emission Reductions (MCF)

2018	2019	2020	2021	2022
NA	NA	NA	24,353	59,021

Emission reductions achieved in 2021 by implementing this activity in the Gas Distribution Service Districts were 24,353 MCF. Due to the 2020 Compliance Plan being approved in late 2020 and the COVID-19 pandemic, the implementation of the Large Leak Prioritization (LLP) program was implemented late in 2021, resulting in emission reductions lower than the estimated 54,646 MCF in the 2020 Compliance Plan. In 2022, the emission reductions achieved by implementing the LLP program were 59,021 MCF. The program was fully implemented in 2022 because the obstacles referenced above delayed progress in the previous year. Emission reductions achieved are displayed in the table above.

Cost Effectiveness Evaluation on Historic Work:

Historical cost effectiveness was not evaluated for the 2020 Compliance Period because SoCalGas did not request any additional funding for this program.

Part 2. Proposed New or Continuing Measure

SoCalGas will not request additional staff for the 2024 Compliance Plan because LLP has been adopted into the leak survey process and leak detection training. LLP will continue to be part of normal base business when detecting and measuring leaks. SoCalGas anticipates using LLP as a way to help determine emissions factors using the data collected for emissions reporting. As SoCalGas looks to reduce its leak inventory for Code 2 steel and Code 2 and 3 plastic leaks to six (6) months, all non-hazardous below ground leaks will eventually be prioritized for repair. The LLP program is now part of base business leak survey activities and will not be requesting funding moving forward in future Compliance Plans.

Part 3. Abatement Estimates

In the 2020 Compliance Plan, SoCalGas estimated a total emission reduction of 54,646 MCF for the systemwide implementation of LLP to be achieved per year over the next three (3) years. Estimated emission reductions are included in the Chapter 1 cost effectiveness calculations of this Compliance Plan since accelerated leak repairs are part of the total leak inventory. No costs are associated with this chapter.

As stated in previous Compliance Plans, SoCalGas anticipates emission reductions achieved by this activity to decline as leak repair time decreases for the overall leak inventory. Accelerated leak repair, increased leak survey, and aerial monitoring, as described in Chapters 1, 2, and 14, will reduce the opportunity for further emission reductions from accelerated leak repair.

Forecast of Emission Reductions from Baseline (MCF)*

2025	2026	2027	2028	2029	2030
44,879	33,659	33,659	33,659	33,659	33,659

*Emission reductions forecast are included in Chapter 1 leak repair cost effectiveness calculations

Part 4. Cost Estimates

SoCalGas will not request funds for this initiative in this Compliance Period.

Part 5. Cost Effectiveness/Benefits

Cost effectiveness cannot be calculated because SoCalGas will not request funding for this measure during this Compliance Period.

Part 6. Supplemental Information/Documentation

Attachment 4A: Historical Project Schedule for Large Leak Prioritization

Chapter 5: Damage Prevention Algorithm and Proactive Intervention

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 24: Dig-Ins and Public Education Program
Expand existing public education program to alert the public and third-party excavation contractors to the Call Before You Dig – 811 program. In addition, utilities must provide procedures for excavation contractors to follow when excavating to prevent damaging or rupturing a gas line.
Best Practice 25: Dig-Ins and Company Standby Monitors
Utilities must provide company monitors to witness all excavations near gas transmission lines to ensure that contractors are following utility procedures to properly excavate and backfill around transmission lines.
Best Practice 26: Dig-Ins and Repeat Offenders
Utilities shall document procedures to address Repeat Offenders such as providing post-damage-safe excavation training and on-site spot visits. Utilities shall keep track and report multiple incidents, within a 5-year period, of dig-ins from the same party in their Annual Emissions Inventory Reports. These incidents and leaks shall be recorded as required in the recordkeeping best practice. In addition, the utility should report egregious offenders to appropriate enforcement agencies including the California Contractor's State License Board. The Board has the authority to investigate and punish dishonest or negligent contractors. Punishment can include suspension of their contractor's license.

Historic Project Achievements:

In 2019, SoCalGas completed a pilot using four (4) Damage Prevention Analysts (DPA) to engage, educate, and enforce the use of Dig Alert, which involves calling 811 prior to excavation. These communications were triggered by a risk analysis algorithm that flags excavations that may be at a higher risk for resulting in pipeline damages. The pilot resulted in over 2,100 field contacts with excavators, over 200 educational safe excavation training sessions, and 300 damage investigations, thus promoting improved excavation safety. In 2021, SoCalGas continued to develop the damage prevention risk analysis algorithm to utilize the information that would be used to trigger a proactive intervention. Proactive interventions included activities that SoCalGas performed to address potential excavation sites that pose a high risk of damage, resulting in methane emissions. Furthermore, SoCalGas expanded the resources necessary to accommodate implementing the risk analysis algorithm process by hiring an additional six (6) DPAs.

Using the prioritized results from the risk analysis algorithm, SoCalGas personnel communicated with excavators to discuss the project and the importance of locating and protecting natural gas pipes within the project's delineated area. The method of communication included phone calls, text messages, emails, or job site visits prior to the date of excavation. This proactive excavation intervention enabled SoCalGas to minimize methane emissions from preventable damages.

In 2023, the Damage Prevention Algorithm & Proactive Intervention project for the 2022 Compliance Plan period was not approved because of its high standard cost effectiveness and the relatively small forecasted methane emission reductions directly attributable to the practices.

Emission Reductions Achieved:

No updates in emission reductions achieved were made for this Compliance Period.

Cost Effectiveness Evaluation on Historic Work:

No updates in cost effectiveness evaluation on historic work were made for this Compliance Period.

Part 2. Proposed New or Continuing Measure

SoCalGas will not propose new or continuing measures.

Part 3. Abatement Estimates

There are no abatement estimates because SoCalGas will not pursue measures in this Chapter in this Compliance Period.

Part 4. Cost Estimates

SoCalGas will not request funds for this initiative in this Compliance Period.

Part 5. Cost Effectiveness/Benefits

Cost effectiveness cannot be calculated because SoCalGas will not request funding for this Chapter during this Compliance Period.

Part 6. Supplemental Information/Documentation

Attachment 5A: Historic Project Schedule for Damage Prevention Activities

Chapter 6: Advanced Meter Analytics Algorithm

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 17: Enhanced Methane Detection
Utilities shall utilize enhanced methane detection practices (e.g. mobile methane detection and/or aerial leak detection) including gas speciation technologies.

Historic Project Achievements:

Before Advanced Meter technology, SoCalGas detected high gas usage with monthly readings, leading to potential investigation delays of up to 45 days. Since May 2016, with Advanced Meter technology, SoCalGas now uses hourly data to quickly identify and address unusual consumption patterns, reducing investigation times from up to 45 days to within 48 hours. This has enhanced safety and reduced methane emissions by enabling faster response to leaks and excessive consumption.

The Consumption Analytics Team's efforts have led to significant improvements, including the development of algorithms to detect gas consumption anomalies and evaluate millions of data points daily. Achievements by 2020 include over 3,652 safety investigations at customer facilities and communication with 11,251 customers about potential appliance issues.

As part of the 2020 compliance plan, SoCalGas initiated development of a new enhanced algorithm that could assist the existing algorithm used by the Consumption Analytics Team. The objective of the enhancement was to continue find additional non-system leaks to mitigate. However, due to the challenges of the COVID pandemic, the desired work was not completed, and the project was not given approval in the 2022 compliance plan. As such, work was paused in early part of 2023.

The Consumption Analytics Team's existing algorithm continues to operate.

Emission Reductions Achieved:

No updates in emission reductions achieved were made for this Compliance Period.

Cost Effectiveness Evaluation on Historic Work:

No updates in cost effectiveness evaluation on historic work were made for this Compliance Period.

Part 2. New or Continuing Measure

SoCalGas will evaluate under RD&D new algorithms that can be implemented. If the results are encouraging, SoCalGas may propose this chapter again in the future.

Part 3. Abatement Estimates

There are no abatement estimates because SoCalGas will not pursue measures in this Chapter in this Compliance Period.

Part 4. Cost Estimates

SoCalGas will not request funds for this initiative in this Compliance Period.

Part 5. Cost Effectiveness/Benefits

Cost effectiveness cannot be calculated because SoCalGas will not request funding for this Chapter during this Compliance Period.

Part 6. Supplemental Information/Documentation

Attachment 6A: Historical Project Schedule for Advanced Meter Analytics

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 9: Recordkeeping
Written Company Policy directing the gas business unit to maintain records of all SB 1371 Annual Emissions Inventory Report methane emissions and leaks, including the calculations, data and assumptions used to derive the volume of methane released. Records are to be maintained in accordance with G.O. 112-F, succeeding revisions, and 49 CFR 192. Currently, the record retention time in G.O. 112-F is at least 75 years for the transmission system. 49 CFR 192.1011 requires a record retention time of at least 10 years for the distribution system.

Historic Project Achievements:

Measure 1: Data Lake

In the past, developing the Annual Emissions Report required by the NGLAP involved querying various records, which were stored in varying formats, locations, databases, and with various record owners. This made report generation a time-consuming manual process. Additional challenges arose because the electronic systems were not designed for generating reports for emissions, but rather for billing, maintenance, or operational recordkeeping. As a result, the records included varying types of nomenclature relevant to specific departments. To help improve efficiency, SoCalGas developed a Data Lake with automated interfaces from various source systems to help capture data elements required for emissions reporting. In addition, the Data Lake is designed to enable seamless modification of the emissions reporting templates as they evolve annually. The scope of the Data Lake expanded to capture the dynamic improvement of the Company's technical system upgrades and incorporate new emissions estimation methodologies and reporting requirements. Given the granularity of the emissions reports, it was challenging to automate the data collection and processing that was previously performed manually by subject matter experts. However, the automated capture of source system data has reduced the effort needed by the critical experienced staff and made the data capture and reporting process more accurate and reliable.

Milestones Completed:

- Developed the Data Lake with automated interfaces from source systems to support the capture of data elements required for emissions reporting.
- Modified the automated interfaces when source system technical upgrades occurred.
- Enhanced the automated interfaces when new data elements became available.
- Modified and enhanced the automated reports to account for changes to emissions estimation methodologies and reporting requirements.

Milestones Proposed:

- Emissions dashboard expected to be completed by Q4 of 2024.
- Complete automation based on current (i.e., 2023 Reporting Year) reporting requirements for all in-scope reporting categories by Q4 of 2024.

Measure 2: Engineering Data Analytics and Performance Optimization (EDAPO)

SoCalGas developed an initial phase of the Engineering Data Analytics and Performance Optimization (EDAPO) system to provide capabilities to support advanced analytics for Gas Operations, System Integrity, Distribution, Transmission, and Storage. The initial phase completed a proof-of-concept to forecast distribution system pressure excursions using data from 20 electronic pressure monitors. However, the EDAPO system is capable of capturing hourly pressure data for the entire distribution system, and the project also implemented a pilot phase to capture hourly pressure data from 2,000 electronic pressure monitors representing the entire distribution system. The pilot phase used machine learning to forecast 44% of the 25 distribution system pressure excursions that occurred over a four-year period. Although determining the balance between false positives and missed positives was challenging, each avoided pressure excursion reduced the risk of emissions and substantial leak repair costs.

Milestones Completed:

- Completed a proof-of-concept to forecast distribution system pressure excursions using data from 20 electronic pressure monitors.
- Completed a pilot phase using machine learning to forecast distribution system pressure excursions using hourly pressure data from 2,000 electronic pressure monitors.

Measure 3: Asset Field Verification

Prior to the 2018 Compliance Plan, SoCalGas maintenance and inspection work management systems were designed for billing, maintenance, or operational record-keeping purposes only. Moreover, because consistent naming conventions were not in place, records used varying types of nomenclature relevant to specific departments. Querying records from numerous departments in the Company and combining them to generate a single report was challenging and not readily available.

To improve asset data in the Company's source systems, SoCalGas performed Asset Verification projects at its transmission and storage facilities. The Asset Verification projects enhanced existing systems to include additional data elements required for the methane emissions calculations, which enabled field personnel to record required information into systems that were previously incapable of recording certain component data (e.g., manufacturer, date of installation, and photos). Having such data readily available enhanced the emissions estimations for the mandated Annual Emissions

Report associated with these assets, and it has also allowed departments to refer to assets by unified naming methods and improve data governance.

Milestones Completed:

- Field verification of transmission assets completed Q2 of 2023.
- Field verification of storage assets completed Q4 of 2022.

Measure 4: Real-time Data Management for Methane Abatement/Monitoring Support for Other Gas Operational Units

Real-time data management and monitoring is an essential tool to analyze methane emissions and implement efforts to reduce methane emissions effectively across all operational areas. SoCalGas purchased a software license to modernize real-time data management and help improve existing and new methane emissions reduction projects. This tool's operational and maintenance cost will be distributed to the end of 2025 to comply with regulatory accounting requirements. The tool enabled SoCalGas to improve maintenance/performance practices for its assets in transmission, distribution, and storage facilities. Moreover, the collected data is used to develop analytical capabilities to provide the ability to integrate with enterprise initiatives across the Company.

Milestones Completed:

- Obtained Enterprise license.
- Enabled additional analytics capabilities and gained the ability to integrate with other enterprise initiatives.
- Integrated existing infrastructure into the NGLAP solutions to enhance the Company's compliance with methane emissions requirements.

Measure 5: Develop Mobile Field Forms

Prior to the 2022 Compliance Plan, the work management system used by Transmission did not include digitized forms or mobile capabilities. Enhancement efforts to address these deficiencies commenced in 2021 with software module updates to the work management system. The second part of the enhancement was to digitize forms and add mobile and spatial capabilities. Such improvements facilitated data recovery for maintaining assets, improved safety, and eliminated inconsistencies that the paper form may have caused. The digitized forms will also be used for reporting purposes, e.g., SB 1371. The project is anticipated to be completed in Q4 of 2024.

Milestones Completed:

- Modernized and enhanced mobile solutions to have offline capabilities by Q2 of 2022.
- Enabled spatial capabilities to the mobile solution by Q2 of 2022.
- Digitized paper forms and processes are anticipated to be completed by Q4 of 2024.

Measure 6: Historizing Emission Sensor Data (HESD)

The RD&D Pilot – Evaluation of Stationary Methane Detectors – did not identify current monitors that could be deployed to cost-effectively scan for emissions. Therefore, the sensor data intended to be historized by the HESD project does not exist at this time. However, the Emission Reductions Analytical Tools (ERAT) project has shown promise for identifying new areas to target for emissions reductions. As such, the HESD funding was reallocated to ERAT initiatives.

Measure 7: Emission Reduction Analytical Tools (ERAT)

During 2023, a tool for forecasting annual emissions from Distribution Mains and Service leaks was completed within the ERAT portfolio. The tool allows the user to forecast emissions based on targeted repair durations and projected leak counts. The forecasts are instrumental for NGLAP planning and Compliance Plan development, as they are used to strategically select repair durations that will maximize emission reductions in the most cost-effective manner.

Additional tools in the ERAT portfolio are currently under development. Future enhancements are discussed in Part 2 of this chapter.

Milestones Completed:

- Developed requirements.
- Produced a tool for forecasting emissions from Distribution Mains and Service line leaks.
- Initiated development of several tools for identifying areas to focus emission reductions efforts.

Milestones Proposed:

- Implement ERAT tools (Pilot Phase) expected by Q3 of 2024.

Measure 8: Program Process Improvement

The NGLAP focused on the technology, data, and best practices that guide SoCalGas in reducing emissions. The NGLAP is structured to support the elements of developing and submitting regulatory requirements, tracking financials and compliance requirements, guiding consistent messaging, responding to data requests, establishing dashboard(s) with metrics/project controls, and implementing the projects as outlined in the SB 1371 Compliance Plan for emission reductions.

The NGLAP developed and integrated tools to support these efforts that help enhance consistency and accuracy across the program. This allowed for improved tracking of key performance indicators and decision-making. This process improvement utilized tools and methodologies to effectively manage the Program's workflow, including the below workstreams:

- Finance & Regulatory.
- Project Execution.
- Research & Development.
- Policy & Communication.

Project Milestones:

- Created metrics dashboard in support of analytics for decision making and resource planning by Q1 of 2023.
- Digitized paper forms and processes by Q2 of 2024.
- Data storage and report creation by Q4 of 2024.

Emission Reductions Achieved:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific recordkeeping enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits through the execution of Best Practice 9.

Cost Effectiveness Evaluation on Historic Work:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific recordkeeping enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits through the execution of Best Practice 9.

Part 2. Proposed New or Continuing Measures

Measure 1: Data Lake

The measure's objective is to maintain the existing Data Lake while also integrating asset data and capturing updates to reporting requirements, such as template changes and enhancements to emissions estimation methodologies. The Data Lake will continue to implement additional automated integration from new operational systems and updates to existing operational systems. The measure will support maintenance of the internal emissions dashboard mentioned in Part 1 of this chapter.

Project Milestones:

- Integrate asset data.
- Capture changes and updates to regulatory reporting requirements.
- Complete updates and integrations as source systems are updated or modified.

Measure 2: Emission Reduction Analytical Tools, i.e., ERAT

ERAT applies major data analytics to emissions and other utility data (e.g., operational and maintenance data) to analyze, understand trends and convert the emissions data to emission reductions best practices. ERAT helps identify efforts with the best cost-emission reduction ratios based on actual emissions, asset data, and maintenance data. ERAT will be developed to identify emissions sources, associated assets, maintenance processes, and process frequencies. Industry benchmark data and statistical techniques can be employed to determine the emission reductions that can be achieved by modifying maintenance and operational practices. Other initiatives may also be identified and developed by recognizing emission reductions opportunities when replacing equipment at end of life.

Project Milestones:

- Identify the ERAT tools that are most effective during pilot phases in 2024.
- Implement the most effective tools in the NGLAP during 2025.
- Analyze and select additional analytical tools during 2025.
- Initiate pilot phases of additional analytical tools during 2026.

Measure 3: Emissions Data Validation and Governance

The NGLAP gathers and utilizes the best available data for emissions reporting, emissions forecasting, and project development. Millions of relevant data are input into several source systems by multiple departments each year. Although numerous quality control steps are already in place, there is a need for additional validation and governance because these data are critical to the Program.

The Emissions Data Validation and Governance project will assess the Company's relevant data sets and streams, identify areas for improvement, and implement solutions to enhance data quality. This project will assess data that are directly used for emissions reporting and are ingested by data analytics tools. As such, the results of the Emissions Data Validation and Governance project will directly impact the results of the Data Lake and ERAT projects by bolstering the accuracy and reliability of data inputs.

Project Milestones:

- Assess NGLAP data streams and identify specific areas for improvement by Q4 of 2025.
- Implement validation procedures by Q4 of 2026.

Measure 4: Program Process Improvement

This measure will support maintenance of the developed tools as outlined in Part 1 Measure 8 of this chapter, which establish consistency and accuracy across the program and allow for better tracking of key performance indicators and decision making.

Part 3. Abatement Estimates

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific recordkeeping enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits through the execution of Best Practice 9.

Part 4. Cost Estimates

O&M Cost Estimates			
Activity	**2025**	**2026**	**2025 – 2026**
	Direct	**Direct**	**Total Loaded O&M Cost with Contingency**
Data Lake	$418,400	$418,400	$1,131,328
ERAT	$592,840	$432,560	$1,571,790
Validation and Governance	$424,000	$244,000	$1,006,280
Program Process Improvement	$58,100	$58,100	$140,602
Total	$1,493,340	$1,153,060	$3,850,000

Total Revenue Requirement over Expected Life of Investment
$3.9 million
Average Annual Revenue Requirement
$2.0 million

Part 5. Cost Effectiveness/Benefits

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific recordkeeping enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits through the execution of Best Practice 9.

Part 6. Supplemental Information/Documentation

Attachment 7A: Historical Project Schedule for Recordkeeping IT Project-Transmission Facilities

Attachment 7B: Historical Project Schedule for Recordkeeping IT Project-Storage Wellhead Valves

Attachment 7C: Historical Project Schedule for Recordkeeping IT Project-Storage Plant Valves

Attachment 7D: Historical Project Schedule for Recordkeeping IT Project-ERA Tool (Machine Learning)

Attachment 7E: Historical Project Schedule for Recordkeeping IT Project- ERA Tool (Emissions Forecasting)

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 9: Recordkeeping
Written Company Policy directing the gas business unit to maintain records of all SB 1371 Annual Emissions Inventory Report methane emissions and leaks, including the calculations data and assumptions used to derive the volume of methane released. Records are to be maintained in accordance with G.O. 112 F and succeeding revisions, and 49 CFR 192. Currently, the record retention time in G.O. 112 F is at least 75 years for the transmission system. 49 CFR 192.1011 requires a record retention time of at least 10 years for the distribution system. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.
Best Practice 20b: Geographic Tracking
Utilities shall develop methodologies for improved geographic tracking and evaluation of leaks from the gas systems. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve geographic evaluation and tracking of leaks to assist demonstrations of actual emissions reductions. Leak detection technology should be capable of transferring leak data to a central database to be able to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

Historic Project Achievements:

To improve capabilities of leak surveys performed at high pressure facilities, SoCalGas requested in the previous Compliance Plans to back model high pressure facilities in AVEVA and enable scanning technology at facilities with storage and compressor components; AVEVA is a system that enables engineering to create data centric 3D models of facilities. Having these 3D models will make it easier to estimate emission volumes, tie leaks with the company's supply management programs to order replacement parts when needed, identify lead times for replacement, and identify if leaks are on critical systems, which will influence plans for repair.

Since the Program's inception, SoCalGas will have completed the digitizing of approximately 2,300 Piping & Instrumentation Diagrams (P&IDs) for SoCalGas high pressure facilities. These intelligent P&IDs allow the SoCalGas engineering department to locate tags for equipment or instrumentation that is currently found in these facilities. Additionally, several facilities have generated 3D models. To support this ongoing effort SoCalGas will continue to maintain the labor support and resources necessary to maintain the drawings and modeling.

SoCalGas's rights-of-way are posted to GIS by the company's internal employees as part of the land acquisition process. However, historic land agreements are not geospatially depicted in the GIS system. For these historic land agreements, SoCalGas's Land Team conducts site specific rights-of-way research by reviewing strip maps and leak survey maps (company maps) to identify the right-of-way number. Subsequently, the land agreement is reviewed to determine if the land agreement correlates to the specific location. To be able to prioritize the right-of-way location information to be more readily available for leak survey, repair and replacement projects, the historic land agreements will be digitized and mapped to GIS system. The Easement Digitization project has reduced research time by having the accurate right-of-way location mapped to our GIS system because it:

- Saved time and money by identifying the accurate right-of-way locations in GIS and Portal in response to leak survey and repair work within private property.
- Increased productivity and decreased response time to gas operations groups (i.e., Construction Planning, Pipeline Integrity etc.) to reduce emissions and increase safety.
- Efficiently tracked agreements in Portal system with aspatial depiction.
- Digitized a total of approximately 2,800 miles of pipeline easements in approximately 4800 separate rights-of-way.

Emission Reductions Achieved:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, these specific technology enhancements were designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practices 9 and 20b.

Cost Effectiveness Evaluation on Historic Work:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, these specific technology enhancements were designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practices 9 and 20b. This project supports emission reductions by improving the overall response time of operating groups in planning and executing leak survey, as well as repair and replacement projects, by providing the team with accurate and digitally available location information of private right-of-way.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to finalize the QA/QC of complex high-pressure facilities back modeling by Q2 of 2025. The goal of this project is to create a digital model for the existing facilities to enable a quick query of its facilities. The intelligence found in the 3D model and the P&IDs will enable the SoCalGas engineering department and operations to identify, track, and keep proper documentation of the digital asset records. It will enable future reporting from these databases that can include mileage of pipeline, the type of equipment and location, and the capability to connect the 3D model database systems to other SoCalGas database systems. This will enable an increased ability to calculate emission reductions for blowdown and bundled projects, repair leaks quicker, and identify materials with repeated leaks, indicating requirements for replacement.

Complete digitization for an additional 200 miles of pipeline easements, (~1,000 ROW's). Following completion of digital mapping of the historic land agreements in the GIS system, data cleaning will need to be performed on these agreements already stored in SoCalGas' electronic document management system. Currently SoCalGas uploads its pipeline right-of-way agreements to the document management system by scanning and indexing each related agreement, as well as associated data attributes, with specific right-of-way numbers. Users can search for right-of-way agreements based on the specific right-of-way number or the associated data attributes such as grantor, document type, pipeline number and recording information, etc. To further enhance overall response time to the operating groups, incomplete, inaccurate or duplicative data attributes of the historic land agreements will be identified and scrubbed so the data can be modified, corrected or removed, eliminating common data errors that drive up research time. The data cleaning will enable more effective support to the leak survey, repair, and replacement projects with more efficient response time while supporting future to hyperlink the agreements to the digitally mapped rights-of-way in the GIS system.

Part 3. Abatement Estimates

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, these specific technology enhancements were designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practices 9 and 20b.

Part 4. Cost Estimates

O&M			
Activity	**2025**	**2026**	**2025 - 2026**
	Direct	**Direct**	**Total Loaded O&M Cost with Contingency**
Labor	$26,500	$26,500	$116,600
Non-Labor Consultant Support	$367,286	$367,286	$888,832
Mapping Support	$90,000	$90,000	$217,800
Title Services	$20,000	$20,000	$48,400
Back Modeling and QA/QC for Five (5) Compressor Stations & One (1) Storage Facility (AVEVA)	$300,000	-	$412,500
Total	**$803,786**	**$503,786**	**$1,684,132**

Total Revenue Requirement over Expected Life of Investment
$1.7 million
Average Annual Revenue Requirement
$0.9 million

Cost Assumptions:

- Labor: 0.5 FTE.
- Non-labor: 1.5 FTE Consultant support.
- AVEVA QA/QC is estimating three (3) months of work to close project in 2025.

Part 5. Cost Effectiveness/Benefits

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, these specific technology enhancements were designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practices 9 and 20b.

Part 6. Supplemental Information/Documentation

Attachment 8A: Historical Project Schedule for Geographic Tracking

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 13: Performance Focused Training Program
Create and implement training programs to instruct workers, including contractors, on how to perform the BPs chosen, efficiently and safely. Training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or CBC processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.

Historic Project Achievements:

Gas Operations Training has been driven by a strong emphasis on PHMSA's safety regulations. The NGLAP required an additional emphasis on the control of emissions. As changes in processes, procedures, equipment, and technology emerge due to implementation of Best Practices, existing training needed to be modified and new training modules developed. This training supports the new process, policies and trains new employees with an increased focus on the environmental impact of methane emissions on the atmosphere.

SoCalGas continued to implement its competency-based training program which encompassed training designed for all new methane mitigation policy and procedural changes. SoCalGas has continued to transition away from a traditional classroom training approach towards a competency-based web-based video training module system which has enhanced the ability to incorporate new policies and increase learning at a faster pace.

Currently, SoCalGas is changing from scheduled classes that start and end on specific dates, to an on-demand training paradigm. The individualized instruction environment allows students to begin training anytime for specific courses, and those courses conclude when the student has demonstrated competence. The instructor's role is changing from the primary dispenser of instructional content to a facilitator of learning by coaching, mentoring, and observing hands-on activities performed by students. This new training format is increasing the speed of competency development for the previously implemented courses.

These training modules helped implement new policies/procedures, quickly fill vacancies for technicians / fill gaps in existing technicians' education, decreased the number of errors in the field, and increased safety. All of these factors contributed to SoCalGas's methane emission reductions.

Emission Reductions Achieved:

Because this measure is a technology enhancement and/or process improvement(s) that supports the overall Program, emission reductions and cost effectiveness benefits directly attributed to its implementation cannot be fully calculated. However, due to shifting courses online, we have been able to calculate the following which only accounts for travel saved during the training itself.

2020		2021	
Emissions Saved (MCF)	**Total Miles Saved**	**Emissions Saved (MCF)**	**Total Miles Saved**
2.38	2,676	16.08	17,880
2022		**2023**	
Emissions Saved (MCF)	**Total Miles Saved**	**Emissions Saved (MCF)**	**Total Miles Saved**
17.03	18,921	14.88	16,533

Part 2. Proposed New or Continuing Measure

Historically, Gas Operations Training has been driven by a strong emphasis on PHMSA's safety regulations. The NGLAP requires an additional emphasis on the control of emissions. As changes in processes, procedures, equipment, and technology emerge due to implementation of Best Practices, existing training needs to be modified and new training modules developed. This training will support the new process, policies and train new employees with an increased focus on the environmental impact of methane emissions on the atmosphere.

SoCalGas proposes continuing to create and implement a competency-based training program specifically for the Lead Planning Associate (LPA) and Field Planning Associate (FPA) positions, and a dashboard which will help curate, monitor, update, and amend existing/future courses and modules. This will allow SoCalGas to continue transitioning from a traditional classroom training approach to a competency-based web-based video training module system to enhance the ability to incorporate new policies and increase learning at a faster pace.

Changes to the Gas Operations Training department operations will be ongoing as additional courses and modules are created and implemented. This is intended to facilitate transitioning from a classroom style learning environment to one that is more individualized.

Creating these additional training modules will assist in implementing new policies/procedures, fill gaps in employee competency, increase in-field accuracy, and reduce hazards. These efforts will better enable SoCalGas to reduce methane emissions in other areas as well as further reduce direct emissions due to travel.

Project Milestones:

- Establish scope of work for training modifications: Q1 of 2025 – Estimated 3 months.
- Develop instructional Design: Q2 of 2025 -Estimated 9 months.
- Develop training materials: Q2 of 2025 - Estimated 9 months.
- Evaluate training materials and train-the-trainer: Q1 of 2026 Estimated 6-12 months.
- Implement Training: Q1 of 2026 - Estimated 6-12 months.

Part 3. Abatement Estimates

Because this measure is a technology enhancement and/or process improvement(s) that supports the overall Program, emission reductions and cost effectiveness benefits directly attributed to its implementation cannot be calculated.

Part 4. Cost Estimates

O&M Cost Estimates			
Activity	**2025**	**2026**	**2025 - 2026**
	Direct	**Direct**	**Total Loaded O&M Cost with Contingency**
Curriculum Design (LPA)	$400,000	$350,000	$907,500
Curriculum Design (FPA)	$325,000	$225,000	$665,500
Dashboard	$88,000	-	$106,480
Total	**$813,000**	**$575,000**	**$1,679,480**

Total Revenue Requirement over Expected Life of Investment
$1.7 million
Average Annual Revenue Requirement
$0.9 million

Cost Assumptions:

- One (1) FTE at $120,000 to support managing the project and coordinate with consultant to design curriculum.

Part 5. Cost Effectiveness/Benefits

Because this measure is a technology enhancement and/or process improvement(s) that supports the overall Program, emission reductions and cost effectiveness benefits directly attributed to its implementation cannot be calculated.

Part 6. Supplemental Information/Documentation

Attachment 9A: Historical Project Schedule for Competency Based Training Development

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 13: Performance Focused Training Program
Create and implement training programs to instruct workers, including contractors, on how to perform the BP's chosen, efficiently, and safely. Training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or CBC process, then the Company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.

Historical Project Achievements:

SoCalGas has a robust classroom training program provided at a centralized training facility in Pico Rivera. The training facility is equipped with an area known as Situation City, where trainees can experience hands-on real-world scenarios, such as blowing high-pressure lines with an ignition source, while in a controlled and safe environment. Training programs are focused primarily on PHMSA's safety regulations. Per SoCalGas's SMS, "competence, awareness, and training" are one (1) of the Company's seven (7) core Safety Values. All current training programs are focused around incorporating safety in all procedures as a primary goal. As part of its formal training program and Operator Qualification requirements, SoCalGas incorporates hands-on elements at Situation City.

Situation City consists of 22 "homes" set up on residential streets with gas meters, gas mains, and services in the streets. In addition to a certified training area for Cathodic Protection training, meter read training, and firefighter training, this facility can train students using a real, working gas distribution system in a safe, controlled environment. After Completion of the previous Situation City improvements to the leak detection course we can now simulate gas leaks at approximately 1 CFH for training purposes. These new simulations allow for training to detect much smaller leaks in an effort to further reduce emissions and increase safety.

Part 2. Proposed New or Continuing Measures

SoCalGas proposes to continue improving its training facility with a simulated transmission station, plug valve maintenance and repair props, locate and mark field, and pressure control props. With the addition of these props, training assemblies & training course, trainees would be better enabled to gain knowledge, skills, & experience in a safe, controlled environment, with an improved understanding of the necessary maintenance and repair operations.

Training assemblies for Transmission Control Stations, Plug Valves, and Pressure Control Assemblies will be fully functional and composed of up-to-date equipment, which matches those in the field. These assemblies would be installed at "Situation City" to further expand its educational capacity.

Installing a new training course would allow for faster and more accurate gas line location and marking. This could decrease completion times for those activities, and the occurrences of line striking. The course would be laid out inside "Situation City" and add another layer of realism to the training environment. The course would include a variable controller to allow teachers to change the course to best suit the needs of the student's experience level.

These additional training props and course will result in less errors in-field, increase safety, & reduce time to repair/maintain lines & equipment. These activities are performed across many different departments, and all indirectly result in methane emission reduction.

Milestones Proposed:

(For both Training Assemblies & Training Course)

- Establish Scopes of Work: Q1 of 2025 – Estimated four (4) months.
- Procure Design Documents: Q2 of 2025 – Estimated four (4) months.
- Obtain Materials: Q3 of 2025 – Estimated three (3)-six (6) months.
- Construction: Q4 of 2025 – Estimated six (6)-nine (9) months.

Part 3. Abatement Estimates

Because this measure is a technology enhancement and/or process improvement(s) that supports the overall Program, emission reductions, and cost effectiveness benefits directly attributed to its implementation cannot be calculated.

Part 4. Cost Estimates

Capital Cost Estimates			
Activity	**2025**	**2026**	**2025 - 2026**
	Direct	**Direct**	**Total Loaded Capital Cost with Contingency**
Project Manager	$120,000	-	$264,000
Equipment Enhancements	$761,250	$253,750	$1,228,150
Training Assemblies	$176,250	$58,750	$284,350
Total	$1,057,500	$312,500	$1,776,500

Total Revenue Requirement over Expected Life of Investment
$2.8 million
Average Annual Revenue Requirement
$0.04 million

Cost Assumptions:

- Project Manager to manage scope of project with annual salary of $120K.
- Construction to complete work at approximately $750K. The estimate is based on Contractor's proposal using time and material.

Part 5. Cost Effectiveness/Benefits

Because this measure is a technology enhancement and/or process improvement(s) that supports the overall Program, emission reductions, and cost effectiveness benefits directly attributed to its implementation cannot be calculated.

Part 6. Supplemental Information/Documentation

Attachment 10A: Historical Project Schedule for Training Facility Enhancement

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 23: Minimize Emissions from Operations, Maintenance and Other Activities
Utilities shall minimize emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e. no-bleed) or vents significantly less natural gas (i.e. low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

Historic Project Achievements:

In the 2022 Compliance Plan, SoCalGas was not approved to implement emission reductions efforts at Storage Facilities. From 2018 to 2021, SoCalGas implemented over 17 projects that reduced emissions from storage facilities. These projects included the modification/removal of orifice meters, replacement of chemical injection pumps with ventless types, reduction of wellhead venting, gas blowdown studies, and the replacement of gas-powered actuation with compressed air.

To support these efforts, SoCalGas staffed a Project Manager to support emission reductions projects in storage operations.

In addition to staffing efforts, SoCalGas published Gas Standard GS 223.0155, *Planning Pipeline Blowdowns and Reporting,* to outline the methods of blowdown reduction and provide resources to Planners and Project Managers when planning pipeline blowdowns and the associated blowdown reductions.

Emission Reductions Achieved:

The Underground Storage Emissions reported as the baseline in 2015 were 112,076 MCF. Underground Storage Emissions reported in the calendar year 2018 were 43,481 MCF, with an estimated reduction of 68,595 MCF. Underground Storage Emissions reported in the calendar year 2019 were 23,750 MCF, with an estimated reduction of 88,326 MCF. Underground Storage Emissions reported in the calendar year 2020 were 10,178 MCF, with an estimated reduction of 101,898 MCF. Underground Storage Emissions reported in the calendar year 2021 were 14,134 MCF, with an estimated reduction of 97,942 MCF. Underground Storage Emissions reported in the calendar year 2022 were 10,351 MCF, with an estimated reduction of 101,725 MCF. The following table summarizes these reductions.

Historical Emission Reductions (MCF)

2018	2019	2020	2021	2022
6,879	7,115	9,029	8,658	8,865

Cost Effectiveness Evaluation on Historic Work:

Historical Standard Cost Effectiveness ($/MCF)

Projected in 2022 Compliance Plan	Actual Cost Effectiveness (2018-2022)
N/A	$39

Part 2. Proposed New or Continuing Measure

Although SoCalGas was not approved for cost recovery for additional work proposed in this chapter in the 2022 Compliance Plan, SoCalGas has been directed to study a cost-effective way to track blowdown emissions at Storage Fields. SoCalGas plans to utilize the R&D team to study how Compressor Vented Emissions can be better tracked for blowdown occurrences at Storage Fields. By exploring a cost-effective opportunity to reduce emissions, SoCalGas can then implement this new measure in Storage Operations. The funding for this study is being requested as part of R&D Summary #23.

No additional incremental staffing is forecasted to support this measure during this Compliance period.

Part 3. Abatement Estimates

There are no abatement estimates because SoCalGas will not pursue measures in this Chapter in this Compliance Period.

Part 4. Cost Estimates

SoCalGas will not request funds for this initiative in this Compliance Period.

Part 5. Cost Effectiveness/Benefits

Cost effectiveness cannot be calculated because SoCalGas will not request funding for this measure during this Compliance Period.

Part 6. Supplemental Information/Documentation

Attachment 11A: Historical Project Schedule for Blowdown Reduction Projects at Storage

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 18: Stationary Methane Detectors
Utilities shall utilize Stationary Methane Detectors for early detection of leaks. Locations include: Compressor Stations, Terminals, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R above ground and pressures above 300 psig only). Methane detector technology should be capable of transferring leak data to a central database, if appropriate for location.

Historical Project Achievements:

SoCalGas conducted a phased study of stationary methane detection technologies at company facilities from 2018-2022. This activity explored a range of alternative monitoring technologies to assess their accuracy, propensity to generate false alarms, and ongoing Meter and Regulating (M&R) stations. The sites were operating stations so the data gathered would be representative of real-world conditions. SoCalGas included sensors from multiple tunable diode vendors in the evaluation to assess their relative performance in comparison to each other and to the results of on-site leak surveys. The results of the evaluation determined that implementation of stationary methane detector technology at above ground Distribution M&R regulator stations was not cost-effective for early leak detection compared to performing additional leak surveys.

Emission Reductions Achieved:

Historical Emission Reductions (MCF)

2018	2019	2020	2021	2022
279	279	279	-	-

Cost Effectiveness Evaluation on Historic Work:

The results of the evaluation determined that implementation of stationary methane detector technology at above ground Distribution M&R regulator stations was not cost-effective for early leak detection compared to performing additional leak surveys, as discussed in the 2021 CPUC Winter Workshop.

In 2021, SoCalGas moved the focus of the evaluation of methane sensor feasibility and cost effectiveness to Transmission facilities. This effort will focus on the potential for sensor installations at Transmission M&R and compressor stations. Additionally, this measure will include controlled laboratory evaluations of alternative stationary methane detectors.

Part 2. Proposed New or Continuing Measure

SoCalGas performed a research study on Stationary Methane Detectors intending to install methane sensors for early leak detection at 50 Transmission facilities. However, the research study has shown that the sensors are not cost effective. SoCalGas will not continue this measure moving forward.

Part 3. Abatement Estimates

There are no abatement estimates because SoCalGas will not pursue measures in this Chapter in this Compliance Period.

Part 4. Cost Estimates

SoCalGas will not request funds for this initiative in this Compliance Period.

Part 5. Cost Effectiveness/Benefits

Cost effectiveness cannot be calculated because SoCalGas will not request funding for this Chapter during this Compliance Period.

Part 6. Supplemental Information/Documentation

Attachment 12A: Historical Project Schedule for Stationary Methane Detectors

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 20b: Geographic Tracking
Utilities shall develop methodologies for improved geographic tracking and evaluation of leaks from the gas systems. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve geographic evaluation and tracking of leaks to assist demonstrations of actual emission reductions. Leak detection technology should be capable of transferring leak data to a central database in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

Historical Project Achievements:

Using digital and mobile technology, SoCalGas automated the leak survey process, with the goals of reducing costs, increasing processing efficiency and visibility of this critical safety activity. Leak survey instrumentation was used to track leaks and generate data, which was then electronically uploaded into GIS. Breadcrumb (GIS Location) data was collected for developing the Electronic Leak Survey (ELS) mobile application. The ELS project replaced the existing distribution routine leak survey process involving paper maps with:

- GIS web-based portal application that was used to electronically prepare, review, audit, and store leak survey map completions.
- Mobile application on an iPad device that was used by operator qualified technicians to report leak survey completions and to document conditions found that require follow-up, such as leaks.
- Highly integrated solution with GIS, SAP, and CLICK that leverages SoCalGas's existing enterprise systems and business workflows to auto-create and generate follow-up work orders.
- Dashboard for managing near real-time work order status and completion.

The ELS project tested the release of the mobile application resulting in its training and deployment. As implementation continued, the gas system benefitted from improved geographic evaluation and tracking of leaks, Atmospheric Corrosion (ACOR), and other Abnormal Operating Conditions (AOC) locational data using smart forms. Furthermore, point and CLICK technology using GIS coordinates allowed information, such as addresses, to be auto populated. The project schedule for the 2022 Compliance period was extended due to unexpected and complex technical issues discovered in 2021, resulting in phasing the rollout schedule. Once the scopes outlined in the 2022 Compliance Plan including AOC and Pipeline Patrol are completed, it will become the prerequisite for the future scope Advanced Analytics as discussed in Part 2 of this chapter.

Emission Reductions Achieved:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific technology enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 20b. Once fully deployed, the project will improve geographic tracking and evaluation of gas system leaks. We will showcase these benefits with specific metrics in future Compliance Plans.

Cost Effectiveness Evaluation on Historic Work:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific technology enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 20b through the following metrics:

- 187 million feet of pipeline surveyed.
- Over 32,000 work orders completed.
- 20,880 new leaks recorded.
- 3,519 hours in leak response time saved.

Part 2. Proposed New or Continuing Measure

As the initial distribution routine survey implementation for ELS continues, there is an expectation that new enhancement requests will become apparent as the digitization of paper maps is deployed and employees utilize it in the field. Software packages will go through upgrade cycles and the underlying product will continue to be upgraded by vendor to provide additional functionality and stability. After deployment is complete, SoCalGas will maintain distribution routine leak survey implementation as well as Pipeline Patrol and AOC implementation.

At the time of this submittal, the following scopes are anticipated to be completed by the end of the 2022 Compliance Period.

Electronic Leak Survey: Abnormal Operating Conditions (AOC)
Scope:
This project includes build/configuration, test, and deploy of Special leak survey functionality including:

- Leverage existing ELS mobile application deployed on mobile devices and Breadcrumb Tracking.
- Capture and record conditions found during special leak survey that require follow-up such as leak indications or other AOCs.
- SAP Work Order (SAP WO) generation and enhanced integrations, transferring captured AOC data to SAP.
- Capability to create special leak surveys on demand and confirm all identified pipelines are leak surveyed / patrolled before completion.

- Leverage GIS capacity to quickly identify locations requiring special leak survey and generate leak survey work orders.

Electronic Leak Survey: Pipeline Patrol
Scope:
- Mobile application and Pipeline Patrol maps on mobile devices and capture Breadcrumb data.
- Capturing conditions that require follow-up such as missing markers, class location changes, encroachments, etc.
- SAP WO order generation and enhanced integrations.
- Confirm all required high-pressure pipelines have been patrolled as required.

The following scope is anticipated to be completed by the end of the 2024 Compliance Period.

Electronic Leak Survey: Advanced Analytics
Scope:
- Through the implementation of ELS, SoCalGas will collect quality data on pipeline assets, gas leaks, and other AOCs. Leveraging ELS data to conduct advanced analytics can provide opportunities to understand and proactively address gas leaks. These analytics include:
  - Predicting and preventing failing assets through machine learning algorithms.
  - Optimizing maintenance schedules and work assignments [i.e., Can't Get In's (CGIs)] by correlating geo-spatial information of follow-up orders with customer data (advanced meter).
  - Producing plume maps to visualize areas with increased methane concentration; expanding visibility of surveys with interpolation to identify potential gas leaks.
- By analyzing data from ELS, patterns and trends in gas leaks and conditions that require follow-up can be identified, allowing for more targeted corrective measures.

Benefits:
- Creates cost savings associated with plotting, printing, reviews, and mailing of paper-based leak survey maps. Eliminates preparing, printing, review, monitoring, re-work, associated with paper maps that are lost and result in re-work.
- Reduces risk and wait times for leak survey maps during significant events such as system overpressure, earth movement, fires, floods, etc. which improves productivity, increases safety, and enables field personnel to respond more quickly.
- Automates the leak survey process in Distribution creating efficiency, flexibility in cross district assignment and routing, and improves utilization of workforce since there is no longer dependency on paper maps.
- Integrates with SAP and improves geographic location data, tracking of leaks, and other AOCs that require follow-up. GIS coordinates will be auto-populated minimizing room for user error.
- Improves efficiency by eliminating manual processes and allows the ability to track pipelines that are surveyed or patrolled.

- Results from advanced analytics can lead to benefits such as reduced costs, improved safety, and increased operational efficiency.
- Patrollers can receive near real-time status updates of activities via the app which was previously not accessible on-the-go.

Project Milestones:

- ELS – Advanced Analytics: Q4 of 2026.

Part 3. Abatement Estimates

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific technology enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 20b. Once fully deployed, the project will improve geographic tracking and evaluation of gas system leaks. We will showcase these benefits with specific metrics in future Compliance Plans.

Part 4. Cost Estimates

O&M Cost Estimates			
Activity	2025	2026	2025 – 2026
	Direct	Direct	Total Loaded O&M Cost with Contingency
Contractors	$633,000	$316,000	$2,087,800
Internal Labor	$333,000	$166,000	$1,097,800
Total	**$966,000**	**$482,000**	**$3,185,600**

Capital Cost Estimates			
Activity	2025	2026	2025 - 2026
	Direct	Direct	Total Loaded Capital Cost with Contingency
Software	$464,000	$229,000	$838,530
Hardware	$100,000	-	$121,000
Contractors	$770,000	$380,000	$2,323,200
Internal Labor	$405,000	$200,000	$2,219,800
Vendor Services	$281,000	$138,000	$847,000
Total	**$2,020,000**	**$947,000**	**$4,189,020**

Total Revenue Requirement over Expected Life of Investment
$8.7 million
Average Annual Revenue Requirement
$0.1 million

Cost Assumptions:

- Contractor Support and Vendor Services line items include cost estimates from multiple vendors based on total project scope performing services for system maintenance, design, development, testing, training, and deployment.
- Software purchase includes vendor license and software upgrades for enterprise license.
- Hardware purchase includes server cabinets, devices, and accessories.
- Internal labor will cover multiple FTEs conducting various tasks, such as system maintenance, project management, coordination with contractors, and internal departments and QA/QC.

Part 5. Cost Effectiveness/Benefits

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific technology enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 20b. Once fully deployed, the project will improve geographic tracking and evaluation of gas system leaks. We will showcase these benefits with specific metrics in future Compliance Plans.

Part 6. Supplemental Information/Documentation

Attachment 13A: Historical Project Schedule for Electronic Leak Survey

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 16: Special Leak Surveys
Utilities shall conduct special leak surveys, possibly at a more frequent interval than required by G.O. 112-F (or its successors) or BP 15, for specific areas of their transmission and distribution pipeline systems with known risks for natural gas leakage. Special leak surveys may focus on specific pipeline materials known to be susceptible to leaks or other known pipeline integrity risks, such as geological conditions. Special leak surveys shall be coordinated with transmission and distribution integrity management programs (TIMP/DIMP) and other utility safety programs. Utilities shall file in their Compliance Plan proposed special leak surveys for known risks and proposed methodologies for identifying additional special leak surveys based on risk assessments (including predictive and/or historical trends analysis). As surveys are conducted over time, utilities shall report as part of their Compliance Plans, details about leakage trends. Predictive analysis may be defined differently for differing companies based on company size and trends.
Best Practice 17: Enhanced Methane Detection
Utilities shall utilize enhanced methane detection practices (e.g. mobile methane detection and/or aerial leak detection) including gas speciation technologies.
Best Practice 20a: Quantification
Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks to assist in the demonstration of actual emissions reductions.

Historic Project Achievement:

Between 2019 and 2020, SoCalGas evaluated aerial Light Detecting and Ranging (LIDAR) technologies for detecting and quantifying methane emissions, covering 154 square miles and inspecting extensive pipeline networks in diverse terrains. This technology proved effective in mapping and estimating methane emissions. The pilot also developed data processing methods and strategies for emission reduction and cost effectiveness assessment.

From 2021, SoCalGas expanded this to a system-wide implementation, focusing on Non-State-of-the-Art (NSOTA) pipelines and increasing the covered area to 580 square miles annually. By February 2022, flight frequency increased to three (3) per week, improving data systems, training, and workflows. By May 2022, this further increased to six (6) flights weekly with two (2) helicopters. By the end of 2022, SoCalGas upgraded to the more sensitive 2nd generation sensor, enhancing leak detection. A summary of 2021-2023 results is in the table below.

2021-2023 Leak Detection Results

Line			2021	2022	2023
1	Scanned (Sq miles)		569	2,496	1,464
2	Mains and Services Scanned (miles)		18,281	65,599	44,427
3	Customer Parcels Scanned		933,799	2,994,752	1,911,265
4	Leak count	System	244	946	578
5		Non-system	308	1,143	1,096
6	Customer Incomplete Combustion count		356	975	899
7	Gas-Shut off[1] Count		117	347	430

1. If customer leak cannot be isolated, the service is shut off.

Approximately 36% (Line 7 / Line 5) of customer leaks required their gas to be shut off because the leak cannot be safely isolated. To restore service, SoCalGas technicians verify that the leak and any hazardous conditions have been eliminated. Consequently, for these customers, SoCalGas was able to track the leak abatement rate, showing that greater than 98% of these leaks were fixed. For non-system emission abated calculations presented later, SoCalGas is assuming that for these customers (36% of all non-system leaks) 98% have abated their leaks.

As part of its 2022 Compliance Plan and in the first half of 2023, SoCalGas identified the closer tracking of customer leak abatement as an area for improvement. In the second half of 2023, SoCalGas implemented a tracking and follow-up data system for the remaining 64% of customers — those whose service was not shut off because their leaks could be isolated safely. Although customer follow-up is ongoing, SoCalGas has a contact rate of 50% of these customers - with 70% of those contacted confirming they have either repaired the leak, removed the leaking line, or continued to isolate the line. As such, for non-system emission abated calculations, SoCalGas is assuming that for these customers (64% of all non-system leaks), SoCalGas will successfully contact back 50% of these customers, and 70% of those contacted would have abated their leaks.

Of the non-system leaks that were not shut off (64% of total customer leaks), 50% of the customers have not yet responded. For these non-responsive customers, SoCalGas is not assuming any leak abatement in the numbers presented below.

In 2024, SoCalGas will continue to document the remediating actions of the 50% of non shut-off customers not yet reached. Given the historically high compliance rate (70%), it is probable that as the non-contactable customers are eventually reached, a large percentage of them would have also remedied their leaks.

In the fourth quarter of 2023, the project team presented opportunities related to incomplete combustion (line 6) to the SoCalGas Customer Energy Solutions team. The teams are now collaborating on next steps to implement some of the energy efficiency projects that AMM has identified. As indicated, the potential for addressing incomplete combustion is significant, and the project team is optimistic about realizing some of these opportunities. However, it is too early to quantify the potential impact, and, as such, incomplete combustion abatement is not included in the cost effectiveness calculation for past or future years.

Completed Milestones:

- IT System enhancements completed (2022).
- Scanned greater than 80% of NSOTA lines (2022).
- Ramped up to two (2) sensors flying three (3) days per week (2022).
- Upgraded sensor from 1st generation to 2nd generation (2022).

Emission Reductions Achieved:

The project was in its R&D pilot phase until 2020, then moved to the implementation phase. The 'Historical Project Achievement' section details the number of leaks found. The table below outlines the estimated emission reductions.

Actual emission reductions significantly exceeded the 2022 Compliance Plan's projection of 31,599 MCF. This is primarily due to the higher-than-anticipated leak flow rates detected by AMM. Earlier estimates were based on average system-wide leak rates, but a 2023 study revealed that AMM-detected leak rates were substantially larger. Consequently, the emission factor for these leaks is higher, leading to an increased estimate of emissions mitigated by the AMM project. The 2020 and 2021 emission estimates in the table below have been revised to account for these higher leak rates.

Historical Emission Reductions (MCF)

Source	2018	2019	2020	2021	2022	2023
SoCalGas	N/A	814	5,191	22,626	141,084	110,305
Confirmed Customer Leaks Abated[1]	N/A	N/A	N/A	45,196	154,046	166,570

[1] Customer side emission estimates use the most recent customer leak rates presented in “Incorporation of AMM/GML Detections into SoCalGas Above and Below Ground Leak-Based Emission Factors” white paper.

Cost Effectiveness Evaluation on Historic Work:

In 2021, COVID-19 pandemic-related issues and initial operational challenges led to limited emission reductions, but full operations began in 2022. The 2023 actual cost effectiveness for all emission sources. This is because from 2021 to 2023, the project incurred $3.379 million in one (1)-time IT costs for setting up the data management system. With the software systems now in place and no further capital IT expenses expected, the only ongoing IT cost will be nominal maintenance included in the 2024 Compliance Plan as part of O&M expenses, as detailed in Part Four (4) of this chapter.

Historical Standard Cost Effectiveness ($/MCF)

Line	**Breakdown**	**Actual Cost Effectiveness (2018-2020)**	**Actual Cost Effectiveness 2021**	**Actual Cost Effectiveness 2022**	**Actual Cost Effectiveness 2023**
1	All costs. System emissions only	N/A. Pilot Phase	209	101	73
2	All costs. System + Confirmed Non-system emissions abated	N/A. Pilot Phase	70	48	29

Excluding IT costs and including abated non-system leak abatement, the 2023 cost effectiveness of the project is approximately $27/mcf, a more accurate prediction of the cost effectiveness for future years.

In 2022 SoCalGas collaborated with the aerial scanning vendor to upgrade the leak detection technology. In 2023 the upgraded technology that was used throughout the year detected 50% more field-verified leaks per square mile. Doing this increased the reducible emission opportunity for the same cost, and therefore helped improve the project cost effectiveness in 2023.

It is important to point out that cost effectiveness does not include additional benefits like identifying opportunities to enhance customer energy efficiency by reducing incomplete combustion, and pinpointing customers who could benefit from the Energy Savings Assistance Program. While some opportunities remain unexploited and others are hard to quantify, they all contribute to enhancing the project's future cost effectiveness.

Additionally, the cost effectiveness discussed above does not detail the substantial safety benefits created by increased leak detection.

Part 2. Proposed New or Continuing Measure

With the funding allocated in the 2022 Compliance Plan, SoCalGas is able to scan approximately 80% of the NSOTA lines each year. The company believes that the historical performance of scanning NSOTA lines and the adjacent customer parcels demonstrates that this project is economical, achieving cost-effectiveness close to $25/MCF. Nonetheless, currently only 80% of the NSOTA line is scanned annually.

SoCalGas suggests increasing the funding to enable the scanning of 100% of the NSOTA lines annually. Given the historical cost-effectiveness, SoCalGas calculations suggest that expanding the project to scan 100% of the NSOTA lines will continue to meet the cost-effectiveness benchmarks.

Project Milestones:

- Re-new key vendor contracts (Q3 of 2024)
- 2024 flight planning schedules (Q4 of 2023).
- Complete close to 100% NSOTA mapping (Q4 of 2025).
- Complete close to 100% NSOTA mapping (Q4 of 2026).

Part 3. Abatement Estimates

System and non-system leaks

Assuming the increase in scope discussed in Part 2 is approved, the forecasted reduction in emission is provided below. This estimate is derived from expectations of finding approximately 800 system leaks and 1,000 non-system leaks each year, and achieving the customer abatement rate discussed in the Historic Project Achievement of Part 1.

Forecast of SoCalGas Emission Reductions from Baseline (MCF)

Source	2025	2026	2027	2028	2029	2030
System Leaks	206,596	206,596	206,596	206,596	206,596	206,596
Non-System Leaks Abated	300,873	300,873	300,873	300,873	300,873	300,873

The project will cover nearly all NSOTA lines and 65% of SOTA lines annually for Gas Distribution Operations. Improvements in LiDAR technology, as seen in 2023, could further increase emission reductions over time.

The current forecasts are based on 2019 pilot studies and the 2021-2024 rollout, using linear models. As technology and data availability improve post-implementation, SoCalGas plans to update its aerial monitoring and provide more accurate forecasts in future Compliance Plans.

Part 4. Cost Estimates

O&M Cost Estimates			
Activity	2025	2026	2025 – 2026
	Direct	Direct	Total Loaded O&M Cost with Contingency
Flights and Project Management Support	7,327,316	7,327,316	16,817,209
Field Support	656,184	656,184	2,887,210
Field Repair	1,081,860	1,081,860	4,708,649
IT Support	660,000	660,000	1,597,200
Total	**9,725,360**	**9,725,360**	**26,010,267**

Total Revenue Requirement over Expected Life of Investment
$26.4 million
Average Annual Revenue Requirement
$13.2 million

Cost Assumptions:

- Five (5) FTEs for leak investigations for customer services field operations.
- Seven (7) FTEs for leak investigations for distribution operations.
- Average Represented Employee Hourly Rate: $44/hour.
- Two (2) Incremental Project Managers at approximately $100K annual salary.
- One (1) Project Manager to oversee the project.
- Three (3) Data Analysts for customer leak investigations.
- 3% contingency is included for flights and project management support. The vendor costs are very well understood at this point and are expected to remain within estimates.
- 10% contingency is included in the total loaded O&M cost for the other line items.
- Actual costs may vary as more information becomes available.

Part 5. Cost Effectiveness/Benefits

System emissions only calculation:

Historical Achieved-Cost Effectiveness Calculations (2018-2022) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits	With Cap and Trade, Social Cost of Methane, and Safety Cost Benefits
$74	$72	$47	$47

Forecast of Cost Effectiveness Calculations (2025-2030) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits	With Cap and Trade, Social Cost of Methane, and Safety Cost Benefits
$61	$59	$35	$35

System + Confirmed Non-system emissions calculation:

Historical Achieved-Cost Effectiveness Calculations (2018-2022) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits	With Cap and Trade, Social Cost of Methane, and Safety Cost Benefits
$33	$30	$6	$6

Forecast of Cost Effectiveness Calculations (2025-2030) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits	With Cap and Trade, Social Cost of Methane, and Safety Cost Benefits
$24	$21	-$3	-$3

Part 6. Supplemental Information/Documentation

Attachment 14A: Historical Project Schedule for Aerial Monitoring

2024 SB 1371 Compliance Plan
Chapter 15: Damage Prevention Public Awareness

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 24: Dig-Ins and Public Education Program
Expand existing public education program to alert the public and third-party excavation contractors to the Call Before You Dig – 811 program. In addition, utilities must provide procedures for excavation contractors to follow when excavating to prevent damaging or rupturing a gas line.
Best Practice 25: Dig-Ins and Company Standby Monitors
Utilities must provide company monitors to witness all excavations near gas transmission lines to ensure that contractors are following utility procedures to properly excavate and backfill around transmission lines.
Best Practice 26: Dig-Ins and Repeat Offenders
Utilities shall document procedures to address Repeat Offenders such as providing post-damage safe excavation training and on-site spot visits. Utilities shall keep track and report multiple incidents, within a 5-year period, of dig-ins from the same party in their Annual Emissions Inventory Reports. These incidents and leaks shall be recorded as required in the recordkeeping best practice. In addition, the utility should report egregious offenders to appropriate enforcement agencies including the California Contractor's State License Board. The Board has the authority to investigate and punish dishonest or negligent contractors. Punishment can include suspension of their contractor's license.

Historic Project Achievements:

SoCalGas implements a federally mandated Public Awareness program, as prescribed in 49 CFR § 192.616, which contributes to enhanced public safety. In addition, the State of California mandates a preconstruction meeting with excavators requesting Locate and Mark support and requires continuous monitoring of all excavations within ten feet of high-pressure pipelines pursuant to Cal. Gov't Code § 4216.2. The Public Awareness program is also driven by the requirements of 49 C.F.R. § 192.616, the technical document, Public Awareness Programs for Pipeline Operators, API RP 1162, and program expansion recommendations by regulators.

During the 2022 Compliance Period, SoCalGas conducted the following activities:

- *Paradigm Excavator Outreach meetings* – Additional excavator safety outreach meetings throughout service territory.
- *SoCalGas Regional Public Affairs (RPA) partnerships* – Support for damage prevention/public with local nonprofits, cities, municipalities utilizing RPA's relationships and contacts.
- *SoCalGas Community Relations nonprofit partnerships* – Damage prevention/public awareness partnerships with major nonprofit organizations utilizing Community Relation's relationships and contacts.
- *Solar/Electrical Contractor printing & postage, printing and postage* – Stand-alone solar/electrical contractor mailer for pipeline safety.

- *Landscaper/Fencer contractor printing, and postage* – Developing new stand-alone pipeline safety mailer for landscaper/fencer contractors.
- *Plumber/sewer contractors* – Developing new stand-alone pipeline safety mailer for plumber/sewer contractors.
- *Major League Baseball (MLB) Los Angeles Angels Outreach* - Damage prevention messaging at Angels Stadium throughout the season with emphasis during National Safe Digging Month and on 811 Day. Damage prevention signage and airing of SoCalGas and safe digging radio commercial at Angels stadium.
- *MLB Los Angeles Dodgers Outreach* – End of season public awareness/damage prevention messaging that included podcast streaming and radio announcements.
- *Common Ground Alliance Collaborations* - 811 Day collaboration with other operators at various MLB games and other events.
- *811 Media Campaign* - Damage prevention messaging during timeframe to include 811 Day. Campaign includes damage prevention and 811 digital contents with social media ads and streaming.
- *Social Media Campaign* - social media campaigns that target certain areas in the service territory.
- *Enertech geofencing program* – Targeted messaging around home improvement stores, heavy equipment rentals, landscaping nurseries, plumbing supply stores that would direct stakeholders to SoCalGas pipeline safety webpages.
- *Community outreach events* – Participation at community events like The Taste of Soul, FLOW Expo, and emergency fairs to provide public awareness and damage prevention materials to stakeholders throughout the service territory.

Emission Reductions and Cost Effectiveness Evaluation on Historic Work

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, these specific marketing campaigns and technology enhancements were designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practices 24, 25 and 26. Through the frequency of 811 calls, SoCalGas demonstrates reduction in damage count resulting in emissions savings as shown below:

Metric	2019	2020	2021	2022	2023
Number of Distribution 811 Tickets	960,855	938,358	1,043,299	1,104,907	1,044,971
Damages Resulting in Emissions	3,081	3,196	2,825	2,791	2,448
Damages per 1000 tickets	3.21	3.41	2.71	2.53	2.34

Part 2. Proposed New or Continuing Measure

Because of the benefits as observed above, SoCalGas proposes to continue conducting incremental outreach and education to the public, contractors, excavators, mailing safe digging procedures to contractors, and maintain the existing number of Full Time Employees (FTE) staffed to support the public awareness program. Continued activities to support this measure include, but are not limited to:

- Utilize the analysis of excavation damage data and cause of incidents to develop and implement a target communication plan that will effectively address the damaging parties and reduce incidents.
- Analyze the effectiveness of pipeline safety communications and engagement strategies.
- Conduct focus groups to refine messaging and strategies based on findings.
- Collaborate with other departments to analyze repeat offender data and develop strategies to reduce damages.
- Work with other departments to leverage external relationships and provide public awareness and damage prevention outreach.
- Being a point of contact for assisting with education services for pipeline and public awareness programs or concerns.
- Lead an employee volunteer program that would be aimed at educating our employees about safe excavation practices and encouraging them to report any observed unsafe digging activities. The 811 Ambassador program would ensure our employees have the necessary tools and knowledge to actively participate in this effort.

Similar to SoCalGas' 2022 Compliance Plan, assessing the relationship between investment in the Public Awareness Program and Third-Party Damages shows that investment in public awareness is negatively correlated with the number of third-party damages to company property. Therefore, an increase in public awareness campaigns and outreach should result in decreased damages and lower emissions related to damages.

SoCalGas proposes to continue funding in these areas to further contribute to lowering the numbers of third-party damages. To continue to maintain the expanded public awareness program, SoCalGas will focus on outreach and education to the general public, outreach to contractors and excavators, and mailing safe digging procedures to contractors. The expanded public awareness program allows SoCalGas to increase focus on minimizing emissions.

This measure will require the continued effort of two (2) FTEs. An Advisor will continue to analyze damage data and use the data to assist in the strategizing of effective communications. The Project Manager will continue to manage incremental projects and programs implemented for the measure.

Part 3. Abatement Estimates

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, these specific marketing campaigns and technology enhancements were designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practices 24, 25 and 26.

Part 4. Cost Estimates

O&M Cost Estimates			
Activity	2025	2026	2025 – 2026
	Direct	Direct	Total Loaded O&M Cost with Contingency
Marketing Material/Programs	$887,000	$887,000	$2,146,540
2 FTEs	$264,000	$264,000	$1,161,600
Total	**$1,151,000**	**$1,151,000**	**$3,308,140**

Total Revenue Requirement over Expected Life of Investment
$3.4 million
Average Annual Revenue Requirement
$1.7 million

Cost Assumptions:

- Annual cost estimate of $132K per FTE for two (2) FTEs (An Advisor and Project Manager).
- Marketing material includes production and distribution of mailers, pamphlets, brochures, promotional items, and additional materials for customers to bring awareness of the requirements. Cost estimates for these materials are based on historical cost and implementations.
- Partnership and sponsorship costs to provide outreach in cities and communities within the service territory.

Part 5. Cost Effectiveness/Benefits

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, these specific marketing campaigns and technology enhancements were designed to improve processes to support the overall Program's goals and objectives, including enhancing public safety and reducing the risk of natural gas leaks and explosions. SoCalGas remains committed to demonstrating its benefits, which align with Best Practices 24, 25 and 26.

Part 6. Supplemental Information/Documentation

Attachment 15A: Historical Project Schedule for Damage Prevention Public Awareness

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 22: Pipe Fitting Specifications
Companies shall review and revise pipe fitting specifications, as necessary, to ensure tighter tolerance/better quality pipe threads. Utilities are required to review any available data on its threaded fittings, and if necessary, propose a fitting replacement program for threaded connections with significant leaks or comprehensive procedures for leak repairs and meter set assembly installations and repairs as part of their Compliance Plans. A fitting replacement program should consider components such as pressure control fittings, service tees, and valves metrics, among other things.

Historic Project Achievements:

Materials meet SoCalGas's Material Specification Properties (MSP) requirements for all components. When materials are received, samples are inspected at a warehouse facility to verify requirements are met. Pipe fittings are components used to join pipe sections together with other fluid control products like valves and pumps to create pipelines. If there are any concerns regarding the quality of materials, including the threaded components and fittings, the Supply Management department is engaged to correct the issue and either engage the current vendor to increase quality assurance standards or begin contract negotiations with alternative vendors to confirm all concerns are addressed.

In 2019, SoCalGas hired a third-party consultant to review its quality control (QC) process and MSP standards to identify consistent requirements across component categories. The results from the investigation identified the need to improve the following processes:

1) Manufacturing and QC.
2) Shipping, Handling, and Storage.
3) Construction and Installation.
4) Operations and Maintenance.

The intent of these improvements was to reduce emissions from threaded pipe fittings by improving manufacture tolerances and thread quality. In 2021, SoCalGas hired a Project Manager to develop a project execution plan. The project execution plan was separated into two (2) phases. Phase One (1) focused on updating the material specifications and QC inspection instruction standards. Phase Two (2) focused on implementing the updated standards during the inspection process, shipping and handling, and construction and installation. A training program was completed during Phase Two (2) to introduce internal stakeholders to recommended best practice improvements. SoCalGas's Gas Standard 185.0300, *MSA - Installing, Rebuilding and Inspections* was updated to include approved thread sealants and an installation procedure. A company Gas Standard was developed for field-fabricated threads to confirm thread geometry was within acceptable tolerances.

Additional accomplishments include:

- Required manufacturers' thread fabrication process and product to conform to the National Pipe Thread (NPT) tolerances.
- Developed and implemented a training program for QC inspection team focusing on updated material standards.
- Required manufacturers to demonstrate higher level of thread quality.
- Confirmed manufacturers conformed to updated material standards from QC programs.
- Conducted quarterly inventory studies to continue generating metrics and monitor thread quality and NPT thread tolerance from manufacturers.
- Enhanced QC inspection process.
- Coordination and data exchange with R&D group on various thread-related studies to continually improve facilitation of program recommendations.
- Provided fitting repair and replacement reports to all internal stakeholders of the process, including QC and MSP engineer, for further evaluation.
- Developed recommendations for fitting replacement program.

Threaded Four (4) new QC Inspectors were hired and incorporated into the Program to support implementation and improve the review processes.

Emission Reductions Achieved:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, these specific QC and QA enhancements were designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 22. Once fully implemented, the project will prevent significant leaks from poor quality pipe threads.

Cost Effectiveness Evaluation on Historic Work:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, these specific QC and QA enhancements were designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 22. Once fully implemented, the project will prevent significant leaks from poor quality pipe threads.

Part 2. Proposed New or Continuing Measure

SoCalGas's continuous improvements in the inspection of threaded components are supported by the QC Inspectors who were hired in 2023. The role of these QC Inspectors will be expanded to include improving test setups and testing efficiency and verifying that the checks being performed on the materials are adequate. SoCalGas will continue to work with component manufacturers to align gauging practices and develop process controls to maintain high material thread quality standards. Along with additional measures, such as utilizing higher rated thread sealants, SoCalGas will continue to evaluate additional feasible solutions based on results of material QC analysis.

SoCalGas will continue to maintain inspection enhancements initiated by Best Practice 22 (BP 22) which requires funding of QC inspectors hired as part of the 2022 Compliance Plan. The QC inspectors will continue to perform inspections on new incoming material received in 2025 and 2026 to maintain the current procedure of inspecting NPT threads per the Quality Control Inspection Instructions (QCII).

Part 3. Abatement Estimates

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, these specific QC and QA enhancements were designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 22. Once fully implemented, the project will prevent significant leaks from poor quality pipe threads.

Part 4. Cost Estimates

O&M Cost Estimates			
Activity	**2025**	**2026**	**2025 – 2026**
	Direct	**Direct**	**Total Loaded O&M Cost with Contingency**
Labor for 4 QC FTEs	$440,000	$440,000	$1,936,000
Contractor to Update MSPs/QCIIs	$197,600	$197,600	$478,192
Inspector	$197,600	$197,600	$478,192
Total	**$835,200**	**$835,200**	**$2,892,384**

Total Revenue Requirement over Expected Life of Investment
$2.9 million
Average Annual Revenue Requirement
$1.5 million

Cost Assumptions:

- Annual cost of $110K per FTE for four (4) QC employees.
- Annual estimated cost of $95 per hour for 2,080 hours (Total $197,600) for contractors.

Part 5. Cost Effectiveness/Benefits

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, these specific QC and QA enhancements were designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 22. Once fully implemented, the project will prevent significant leaks from poor quality pipe threads.

Part 6. Supplemental Information/Documentation

Attachment 16A: Historical Project Schedule for Pipe Fitting Specifications

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 26: Dig-Ins and Repeat Offenders
Utilities shall document procedures to address Repeat Offenders such as providing post-damage safe excavation training and on-site spot visits. Utilities shall keep track and report multiple incidents, within a 5-year period, of dig-ins from the same party in their Annual Emissions Inventory Reports. These incidents and leaks shall be recorded as required in the recordkeeping best practice. In addition, the utility should report egregious offenders to appropriate enforcement agencies including the California Contractor's State License Board. The Board has the authority to investigate and punish dishonest or negligent contractors. Punishment can include suspension of their contractor's license.

Historic Project Achievements:

Best Practice (BP) 26 required a solution for capturing and reporting all dig-in incidents. Incidents caused by contractors are identified using contractor identification data from the California Contractor State License Board (CCSLB). CCSLB data enabled accurate identification and reporting of repeat offenders. Incident information was captured on a paper form called the Company Property Damage Report (CPDR.) The Repeat Offenders IT System project converted the paper form to an electronic form called the eCPDR and made it available on mobile devices. The eCPDR shared the form data across the systems used by the customer Service, Distribution, and Claims departments. The data is also shared with the Data Lake (discussed in Chapter 7), which enables emissions reporting. There were technical challenges in sharing data in real time with robust data security across six (6) systems, with some systems being cloud-based and some supported by different IT vendors. In addition to identifying repeat offenders, the Repeat Offenders IT System eliminated manual effort and potential for data errors in managing paper damage forms, as well as improved the timeliness of reporting through automated data sharing and claim creation. The implementation of the Repeat Offenders IT System commenced in Q1 of 2022.

Milestones Completed:

- Translated Repeat Offenders data to emissions savings.
- Reduced total damages involving repeat offenders by 22% (i.e., 110 fewer damages) from 2022 to 2023.
- Identified and reduced the number of damages from the top 10 offenders during 2023.

Emission Reductions Achieved:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific technology enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits through the execution of Best Practice 26.

Cost Effectiveness Evaluation on Historic Work:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific technology enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits through the execution of Best Practice 26.

Part 2. Proposed New or Continuing Measure

SoCalGas will continue evaluating and integrating the Repeat Offenders IT System as other systems are updated or modified. The Repeat Offenders IT System data will continue to be used to prevent damages and reduce emissions.

Part 3. Abatement Estimates:

Forecast of Emission Reductions (MCF)

2023	2024	2025	2026	2027	2028	2029	2030
2,345	2,345	2,345	2,345	2,345	2,345	2,345	2,345

The forecast assumes that the reductions achieved during 2023 will be maintained through future years; however, it does not consider the additional repeat offenders which may be identified and prevented in future years. Once future data from 2024 and beyond is available, additional reductions can be calculated. The 2023 reductions were determined based on the observed reduction in repeat offender incidents by 110 between 2022 and 2023. The reduction in repeat offender incidents was multiplied by the average emission volume from an Emission Year 2022 excavation damage from the 2023 Annual Emissions Report (i.e., 21.32 MCF) to estimate 2,345 MCF in annual reductions.

Part 4. Cost Estimates

SoCalGas will not request funds for this initiative in this Compliance Period.

Part 5. Cost Effectiveness/Benefits

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific technology enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits through the execution of Best Practice 26.

Part 6. Supplemental Information/Documentation

Attachment 17A: Historical Project Schedule for Repeat Offenders IT Systems

Chapter 18: Accelerated Leak Repair - Transmission

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 21: Find It, Fix It
Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event more than three (3) years after discovery. Utilities may make reasonable exceptions for leaks that are costly to repair relative to the estimated size of the leak.

Historic Project Achievements:

SoCalGas has historically repaired transmission leaks to meet the requirements of 49 C.F.R. Part 192 and the CPUC's G.O. 112-F based on safety risk, and has coded leaks as grades 1, 2, and 3 based on population density, and concentration of the leak. In the past, leak repair prioritization was solely based on safety and was not correlated to emission volumes.

In the 2022 Compliance Plan, SoCalGas was approved to fund accelerated leak repairs beyond the normal repair timeframes. Repairing leaks faster on transmission lines directly attributes to lower emissions.

Emission Reductions Achieved:

During the 2018-2022 Compliance Period, Transmission Operations accelerated eight (8) leaks on transmission assets. Leaks on transmission assets typically emit a larger volume of gas compared to leaks on distribution assets. SoCalGas will continue to accelerate leak repairs on transmission assets when practical. Individual leaks and their grades cannot be reasonably predicted; therefore, there is insufficient data to evaluate emission reductions from this measure.

Currently, emission reductions are being calculated on population-based factors. The Company is continuing to evaluate methodologies to transition to a leak-based emissions model for this category in future Compliance Periods to improve emission estimations.

Cost Effectiveness Evaluation on Historic Work:

There is insufficient data to reasonably calculate emission reductions and cost effectiveness from these activities due to emission reductions being calculated based on the population-based factors.

Part 2. Proposed New or Continuing Measure

SoCalGas continues to accelerate leak repairs on transmission assets when practical. Due to improvements in company outage coordination, SoCalGas does not have the opportunity to save on substantial emissions when accelerating leak repairs. SoCalGas will not request funds for the 2024 Compliance Period.

Part 3. Abatement Estimates

There are no abatement estimates because SoCalGas will not pursue measures in this Chapter in this Compliance Period.

Part 4. Cost Estimates

SoCalGas will not request funds for this initiative in this Compliance Period.

Part 5. Cost Effectiveness/Benefits

Cost effectiveness cannot be calculated because SoCalGas will not request funding for this Chapter during this Compliance Period.

Part 6. Supplemental Information/Documentation

Not applicable.

2024 SB 1371 Compliance Plan
Chapter 19: Gas Speciation

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 17: Enhance Methane Detection
Utilities shall utilize enhanced methane detection practices (e.g. mobile methane detection and/or aerial leak detection) including gas speciation technologies.

Historic Project Achievements:

SoCalGas has a robust laboratory known as the Engineering Analysis Center (EAC). When a methane source is in question, the EAC dispatches a mobile gas speciation van to identify the chemical content of the gas and identify its source.

SoCalGas expanded the capacity of the EAC by increasing staff and equipment to respond to requests from Operations for leak speciation where a methane source is in question. These resources were also required to address lower detection limits of new advanced leak detection instrumentation and the increased level of leak survey activities being driven by the Program.

Emission Reductions Achieved:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific resource and equipment expansion was designed to improve processes to support the overall Program's goals and objectives, including public safety. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 17.

Cost Effectiveness Evaluation on Historic Work:

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific resource and equipment expansion was designed to improve processes to support the overall Program's goals and objectives, including public safety. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 17.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to continue funding the existing lab technicians and hire one additional technician to support the expanded capacity of the Environmental Assessment Center (EAC). This additional resource is needed to respond to requests from Operations for leak speciation due to increased leak surveys and the lower detection limits of new advanced leak detection instrumentation.

Project Milestones:

- Hire and train new employees: six (6) months.
- Purchase and install mobile gas speciation materials in van: As needed.

Part 3. Abatement Estimates

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific resource and equipment expansion was designed to improve processes to support the overall Program's goals and objectives, including public safety. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 17.

Part 4. Cost Estimates

O&M Cost Estimates			
Activity	**2025**	**2026**	**2025 – 2026**
	Direct	**Direct**	**Total Loaded O&M Cost with Contingency**
Three (3) Technicians	$330,000	$330,000	$1,452,000
Lab Materials	$20,000	$20,000	$48,400
Total	**$350,000**	**$350,000**	**$1,500,400**

Total Revenue Requirement over Expected Life of Investment
$1.5 million
Average Annual Revenue Requirement
$0.8 million

Cost Assumptions:

- Annual cost of $110K per Technician for three (3) Technicians.
- Lab materials cost estimate based on historical cost for similar materials/tools.

Part 5. Cost Effectiveness/Benefits

While Senate Bill 1371 generally requires cost-effectiveness analysis for certain projects, this specific resource and equipment expansion was designed to improve processes to support the overall Program's goals and objectives, including public safety. SoCalGas remains committed to demonstrating its benefits, which align with Best Practice 17.

Part 6. Supplemental Information/Documentation

Attachment 19A: Historical Project Schedule for Gas Speciation

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 20b: Geographic Tracking
Utilities shall develop methodologies for improved geographic tracking and evaluation of leaks from the gas systems. Utilities shall work together, with CPUC and ARB staff, to come to an agreement on a similar methodology to improve geographic evaluation and tracking of leaks to assist in demonstrations of actual emissions reductions. Leak detection technology should be capable of transferring leak data to a central database in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

Historic Project Achievements:

In 2023, SoCalGas developed and published publicly available geographic maps of Distribution Mains & Services leak information (e.g., zip codes & volume of emissions). The list of the Distribution Mains & Services leaks is available to the public under Appendix 4 of the Annual Emissions Reports. SoCalGas updates the leak information in Q3 of each year because the submission date of the Annual Emissions Report is usually June 15th of each year. The maps allow customers to navigate the map via zip codes and view the current and historic volume of emissions associated with the zip code. The website address for the maps is as follows: https://www.socalgas.com/stay-safe/distribution-pipelines-emissions-map.

Emission Reductions Achieved:

While Senate Bill 1371 generally requires cost effectiveness analysis for certain projects, this specific technology enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits through the execution of Best Practice 20b.

Cost Effectiveness Evaluation on Historic Work:

While Senate Bill 1371 generally requires cost effectiveness analysis for certain projects, this specific technology enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits through the execution of Best Practice 20b.

Part 2. Proposed New or Continuing Measure

SoCalGas will maintain and annually update the publicly available geographic maps of Distribution Mains & Services Leaks information with the latest data of the Annual Emissions Report.

Project Milestones:

- Update the maps with the Annual Emissions Reports information: Q3 Annually.

Part 3. Abatement Estimates

While Senate Bill 1371 generally requires cost effectiveness analysis for certain projects, this specific technology enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits through the execution of Best Practice 20b.

Part 4. Cost Estimates

O&M Cost Estimates			
Activity	**2025**	**2026**	**2025 – 2026**
	Direct	**Direct**	**Total Loaded O&M Cost with Contingency**
Labor	$5,000	$5,000	$11,000
Non-Labor	$3,080	$3,080	$6,776
Total	**$8,080**	**$8,080**	**$17,776**

Total Revenue Requirement over Expected Life of Investment
$0.02 million
Average Annual Revenue Requirement
$0.01 million

Part 5. Cost Effectiveness/Benefits

While Senate Bill 1371 generally requires cost effectiveness analysis for certain projects, this specific technology enhancement was designed to improve processes to support the overall Program's goals and objectives. SoCalGas remains committed to demonstrating its benefits through the execution of Best Practice 20b.

Part 6. Supplemental Information/Documentation

Attachment 20A: Historical Project Schedule for Public Leak Maps

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 23: Minimize Emissions from Operations, Maintenance and Other Activities
Utilities shall minimize emissions from operations, maintenance, and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e. no-bleed) or vents significantly less natural gas (i.e., low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.
Best Practice 21: Find It, Fix It
Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event more than three (3) years after discovery. Utilities may make reasonable exceptions for leaks that are costly to repair relative to the estimated size of the leak.
Best Practice 19: Aboveground Leak Surveys
Utilities shall conduct frequent leak surveys and data collection at aboveground transmission and high-pressure distribution (above 60 psig) facilities including Compressor Stations, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R aboveground and pressure above 300 psig only). At a minimum, aboveground leak surveys and data collection must be conducted on an annual basis for compressor stations and gas storage facilities.

Historic Project Achievements:

Aboveground leak surveys at Transmission Compressor facilities have historically been completed to meet the requirements of 49 C.F.R. Part 192 and CPUC's G.O. 112-F; California Air Resources Board's (CARB) Oil and Gas Rule became effective January 1, 2018, which requires quarterly leak surveys at several Transmission Compressor facilities. These surveys meet the requirement for Best Practice 19. However, most of the surveys use equipment to detect leaks rather than equipment that measures the concentration of the leak to levels required by the CARB. In addition to the regularly scheduled leak surveys, other surveys are performed using soap tests and by monitoring sight, sound, and smell leak indications.

In the 2020 Compliance Plan, SoCalGas was approved to continue to conduct blowdown reduction efforts in Transmission. The focus has mainly been on Transmission pipelines, but SoCalGas has begun exploring the use of blowdown reduction methods at Transmission Compressor Facilities.

In the 2022 Compliance Plan, SoCalGas was not approved based on insufficient cost effectiveness data. It was recommended that SoCalGas prepare and resubmit in 2024 with expected emissions reductions and cost effectiveness data.

Emission Reductions Achieved:

Historical Emission Reductions (MCF)

2018	2019	2020	2021	2022
N/A	N/A	N/A	N/A	1,378

Emissions reductions for this program are variable due to nature of the project and have not been evaluated for 2018-2021 because SoCalGas did not request any funding for the period.

Cost Effectiveness Evaluation on Historic Work:

SoCalGas is not able to calculate the historical cost effectiveness in 2022 because Leak and Vented Emissions was not a specified measure in the 2020 Compliance Plan. The emissions reduced in 2022 were indirectly piloted by blowdown reduction activities.

Part 2. Proposed New or Continuing Measure

SoCalGas has identified two projects to achieve emission reductions in the 2024 Compliance Period that will be implemented during normal operations at Transmission Compressor Facilities. Additionally, SoCalGas will continue to explore opportunities for emission reductions.

Although new projects may be identified during the Compliance Period, the following projects will be implemented for Transmission Compressor Facilities during this Compliance Period:

- Investigate and develop a quality and maintenance plan for compressor rod packing, which will lead to proactive reduction of vented emissions and identification of non-conforming equipment.
- Investigate downstream capture systems for fugitive emissions.

Part 3. Abatement Estimates

Forecast of Emission Reductions from Baseline (MCF)

2025	2026	2027	2028	2029	2030
4,901	6,821	6,821	6,821	6,821	6,821

Estimated emissions for the rod packing projects are based on the 2022 reported rod packing emissions in pressurized operating mode, which totaled 14,905 MCF for both Transmission and Storage Stations. The 1999 Indaco Air Quality Services, Inc report (see Part 6) estimated that facilities had a rigorous QC and maintenance plan had, on average, vented emissions were 66% less than facilities that only focused on replacement (Page 13, item seven (7) of the 1999 report). The rod packing emissions rates (pressurized operating) at Honor Rancho Compressor Station before and after their improvements efforts in 2020 and 2021 provide a case study as to what we can expect from increased maintenance and operational changes. The overall average reduction was 60% across all five compressor units. Currently, most stations have performed some level of these improvements, so SoCalGas is targeting a conservative 20% savings, leading to 2,981 MCF in savings per year across all compressor stations.

Emissions reductions for the downstream capture systems for fugitive emissions will be dependent on the installation of new capture systems. SoCalGas plans to install two capture systems each year where each capture system will reduce emissions by 960MCF. By the end of 2026, four capture systems will be installed and operational where 3,840MCF in emissions will be reduced annually.

Part 4. Cost Estimates

Capital Cost Estimates			
Activity	**2025**	**2026**	**2025 - 2026**
	Direct	**Direct**	**Total Loaded Capital Cost with Contingency**
Rod Packing Quality Assurance & Maintenance Program	$180,000	-	$331,650
Vented Emissions Capture System	$1,460,000	$1,460,000	$5,354,800
Total	**$1,640,000**	**$1,460,000**	**$5,686,450**

Total Revenue Requirement over Expected Life of Investment
$15.5 million
Average Annual Revenue Requirement
$0.2 million

Cost Assumptions:

- Annual cost of $115K per management FTE.
- 4 FTEs for Rod Packing Project, each spending 25% of time.
- Contractor cost - $45,000.
    - Non-Labor (travel, audit) - $20,000.
- 10 FTEs for each Vented Capture Systems project, each spending 40% of time.
- 2 Vented Capture Systems per year.
- Contractor cost (per capture system) - $100,000.
    - Non-Labor (per capture system).
        - $20,000 – site visit, testing, etc.
        - $150,000 – system and material cost.

Part 5. Cost Effectiveness/Benefits

Forecast of Cost Effectiveness Calculations (2025-2030) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits
$35	$32	$8

Part 6. Supplemental Information/Documentation

Attachment 21A: Indaco Air Quality Services, Inc. (1999). Cost Effective Leak Mitigation at Natural Gas Transmission Compressor Stations PR-246-9526. PRCI

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 23: Minimize Emissions from Operations, Maintenance and Other Activities
Utilities shall minimize emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e., no-bleed) or vents significantly less natural gas (i.e., low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

Historic Project Achievements:

In the 2018 Compliance Plan, SoCalGas requested and was approved for funding to collect emissions data from compressor rod packing systems and install vapor recovery systems on Compressors. The vapor recovery system would collect rod packing emissions which would otherwise be vented to the atmosphere. SoCalGas selected the Blythe Compressor Station as the first Vapor Recovery System project to be evaluated for cost effectiveness before proposing similar systems at other compressor stations. The Blythe Vapor Recovery system allows for the collection of emissions from compressor rod packing that would otherwise be vented directly to the atmosphere. The calculation of total potential emissions savings, assuming the system is 100% effective, is discussed below.

Piston rod packing systems are used to maintain a tight seal around piston rods within compressor engines. These packing systems are designed to vent under normal operation. This estimate is based on a vent rate of two (2) cubic feet per minute (CFM) per packing system, which operated for 439,320 minutes in 2021. There are 12 packings required for the two (2) compressor engines found in the Blythe Compressor Station. The vapor recovery system will reduce emissions on these packing systems, assuming the average operating hours through 2030 remain consistent with the operating hours in 2021, the potential emission reduction is calculated below:

2 CF/min x 439,320 min/year x 6 packings/engine x 2 engines/plant = 10,543,680 CF/year
= 10,544 MCF/year

Emission Reductions Achieved:

Historical Emission Reductions (MCF)

2018	2019	2020	2021	2022
-	-	-	1,860	-

Cost Effectiveness Evaluation on Historic Work:

Cost effectiveness cannot be calculated because funds were not requested for this initiative in the last Compliance Plan.

Part 2. Proposed New or Continuing Measure

Based on the results of the Blythe Vapor Recovery system, SoCalGas has determined that a similar measure at other compressor stations will not be cost-effective. SoCalGas will not proceed with this initiative at other compressor stations. SoCalGas will explore more cost-effective measures at Transmission Compressor Stations to further reduce emissions.

Part 3. Abatement Estimates

Although the Vapor Recovery system was operational from May 2021 to August 2021, the compressors have been out of commission due to a large capital project downstream of the station. Only four (4) months of abatement estimates can be calculated for the Vapor Recovery system, which came to 1,860 MCF of emissions. Assuming the Vapor Recovery Units are in commission for a full year, we estimate the emissions savings to about 5,580MCF per year for the asset's lifetime.

Part 4. Cost Estimates

SoCalGas will not request funds for this initiative in this Compliance Period.

Part 5. Cost Effectiveness/Benefits

Cost effectiveness cannot be calculated because SoCalGas will not request funding for this Chapter during this Compliance Period.

Part 6. Supplemental Information/Documentation

Attachment 22A: Historical Project Schedule for Vapor Collection Systems

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practices:

Best Practice 19 Distribution: Aboveground Leak Surveys
Utilities shall conduct frequent leak surveys and data collection at above ground transmission and high-pressure distribution (above 60 psig) facilities including Compressor Stations, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R above ground and pressures above 300 psig only). At a minimum, above ground leak surveys and data collection must be conducted on an annual basis for compressor stations and gas storage facilities.

Historic Project Achievements:

Above ground leakage surveys have historically been completed to meet the requirements of 49 C.F.R. Part 192 and CPUC's G.O. 112-F, which also satisfy the requirements defined in Best Practice 19. Historically, not all leakage survey inspections performed on Measurement and Regulation (M&R) stations have been performed using instrumentation, resulting in leak indications not being captured. Currently, many of the M&R Stations leak inspections are performed using soap tests and by monitoring for sight, sound, and smell.

In the 2018 Compliance Plan, SoCalGas requested and was approved funding to provide M&R Technicians with instrumentation to begin performing and recording instrumented leakage surveys. SoCalGas purchased the required instruments to perform instrumented inspections. SoCalGas also updated Gas Standard 184.0275, *Inspection Schedule – Regulator Station, Power Generating Plant Regulation Equipment Requirements,* to require M&R Technicians to soap test all connections during inspections and leave facilities free of leaks.

In 2020, SoCalGas ordered approximately 21 Remote Methane Leak Detectors to assist with leak surveys on Regulator Stations. Due to the COVID-19 pandemic, in-person training was postponed with approximately 150 employees needing in-person training for the new instrumentation. In 2021, SoCalGas conducted Train-the-Trainer classes consisting of training supervisors who then would train field personnel. No incremental staffing was required to implement this measure because the measurement tool is an additional piece of equipment that helps detect methane leaks on SoCalGas regulator stations in addition to what is being practiced in the field, as mentioned above.

Emission Reductions and Cost Effectiveness

Historical Emission Reductions (MCF)

2018	2019	2020	2021	2022
N/A	N/A	0	918	1,415

Due to the COVID-19 pandemic, it was not feasible to assess the cost effectiveness of this measure in the 2022 Compliance Plan. However, in 2020 the combination of accelerated surveys and the use of instrumentation to detect leaks at compressor stations, resulted in a net increase in emissions. This increase was expected in the first year of deployment. In the second –year, emissions reductions were achieved due to the accelerated surveys and use of instrumentation as leaks were detected and repaired much sooner than they otherwise would have been. These reductions, along with those achieved in 2022, are reflected in the table above.

Part 2. Proposed New or Continuing Measure

SoCalGas will continue performing instrumented above ground leakage surveys. The required instruments for M&R to perform above ground leakage surveys have been purchased and all qualified employees have been trained. SoCalGas is not requesting additional funding for this measure in this Compliance Period and will be part of base business operations moving for future Compliance Plans.

Part 3. Abatement Estimates

Forecast of Emission Reductions from Baseline (MCF)

2025	2026	2027	2028	2029	2030
1,166	1,166	1,166	1,166	1,166	1,166

The forecasted emission reductions through 2030 represent the average achieved in 2021 and 2022. The reductions are expected to remain similar as the above ground equipment surveyed will remain the same.

Part 4. Cost Estimates

SoCalGas will not request funds for this initiative in this Compliance Period.

Part 5. Cost Effectiveness/Benefits

Cost effectiveness cannot be calculated because SoCalGas will not request funding for this Chapter during this Compliance Period.

Part 6. Supplemental Information/Documentation

Attachment 23A: Historical Project Schedule for Leak Inventory Reduction

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 19: Aboveground Leak Surveys
Utilities shall conduct frequent leak surveys and data collection at aboveground transmission and high-pressure distribution (above 60 psig) facilities including Compressor Stations, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R aboveground and pressure above 300 psig only). At a minimum, aboveground leak surveys and data collection must be conducted on an annual basis for compressor stations and gas storage facilities.
Best Practice 21: Find It, Fix It
Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event, more than three (3) years after discovery. Utilities may make reasonable exceptions for leaks that are costly to repair relative to the estimated size of the leak.

Historic Project Achievements:

Aboveground leak surveys at storage facilities are completed to meet the requirements of 49 C.F.R. Part 192, Subpart M (Maintenance) and CPUC's G.O. 112-F. However, most of the surveys use equipment to detect the leak rather than equipment that measures the concentration of the leak to levels required by the California Air Resources Board (CARB). Effective January 1, 2018, CARB's Oil and Gas Rule requires quarterly leak surveys at storage facilities; as well as requiring storage facilities to implement a monitoring plan effective August 6, 2019. SoCalGas's monitoring plan includes ambient methane monitoring, wellhead leak detection monitoring, and optical gas imaging of a well blowout. In addition to the regularly scheduled leak surveys, other surveys are performed using soap tests and by monitoring for sight, sound, and smell leak indications.

In the 2018 Compliance Plan, SoCalGas was approved to provide Storage Technicians with instrumentation to begin performing EPA Method 21 leak survey and to accelerate leak repairs. SoCalGas purchased the required instruments and has been accelerating leak repairs beyond the timeframes required by regulations and compliance requirements.

To support these efforts, SoCalGas staffed five (5) Station Assistants and one (1) Station Supervisor. A total of six (6) employees are dedicated to implementing this measure.

Emission Reductions Achieved:

Historical Emission Reductions (MCF)

2020	2021	2022
721.4	1323.4	1507.7

Emission reductions have increased from 2020 to 2022. Beginning in 2020, leaks greater than or equal to 1,000 Parts Per Million (PPM) were required to be repaired per the CARB's Oil and Gas Rule. SoCalGas has improved on repairing these leaks under the required timeframe and these efforts have shown great returns in continuing to reduce emissions.

Cost Effectiveness Evaluation on Historic Work:

Historical Standard Cost Effectiveness ($/MCF)

Projected in 2022 Compliance Plan	Actual Cost Effectiveness (2020-2022)
N/A	$937

By tallying the cost combined with the annual emissions from 2020 through 2022, SoCalGas is presented with a high actual cost effectiveness. Although cost effectiveness is not as high as hoped, SoCalGas has been able to reduce the emissions from storage wells by 76% and fugitive components by 25% over the three (3) years. SoCalGas intends to maintain emission reductions and has the opportunity for further reductions in storage fields moving forward.

Part 2. Proposed New or Continuing Measure

SoCalGas requests funding to continue to perform instrumented surveys and to accelerate leak repairs in Storage Operations as much as operationally feasible. SoCalGas proposes to repair all leaks sooner than required by the regulations listed below:

California Geologic Energy Management Division (CalGEM) gas wells

- Methane concentration greater than 50,000 ppm and repaired in less than one (1) day.
- Methane concentration between 10,000 and 50,000 ppm and repaired in less than five (5) days.

CARB's Leak Detection and Repair (LDAR) inspected facilities

- Methane concentration greater than 50,000 ppm and repaired in less than two (2) days.
- Methane concentration between 10,000 and 50,000 ppm and repaired in less than five (5) days.
- Methane concentration between 1,000 and 10,000 ppm and repaired in less than fourteen days.

Beyond the instrumented surveys, SoCalGas is also proposing to utilize Forward Looking InfraRed (FLIR) technology to conduct daily visual inspections which assists in identifying leaks and accelerating leak repairs, thus further reducing emissions and enhancing safety.

Part 3. Abatement Estimates

Forecast of Emission Reductions from Baseline (MCF)

2025	2026	2027	2028	2029	2030
1415.6	1415.6	1415.6	1415.6	1415.6	1415.6

Emission reductions for Storage Leaks & Emissions as well as Compressor and Component Fugitive Leaks are estimated from 2025 to 2030 by taking the average of emissions reduced from 2021 to 2022.

Part 4. Cost Estimates

O&M Cost Estimates			
Activity	**2025**	**2026**	**2025 – 2026**
	Direct	**Direct**	**Total Loaded O&M Cost with Contingency**
Storage Above Ground Leak Survey	$618,288	$618,288	$2,577,907
Total	**$603,288**	**$603,288**	**$2,577,907**

Capital Cost Estimates			
Activity	**2025**	**2026**	**2025 - 2026**
	Direct	**Direct**	**Total Loaded Capital Cost with Contingency**
Capital Equipment Purchases (FLIR Equipment)	$235,000	-	$258,500
Total	**$235,000**	**-**	**$258,500**

Total Revenue Requirement over Expected Life of Investment
$2.6 million
Average Annual Revenue Requirement
$1.3 million

Cost Assumptions:

- Represented Employee Hourly Rate: $41.47.
- Five (5) Station Technician FTE's.
- One (1) Station Supervisor.
- $115K annual salary for Supervisor and FLIR Operator.
- $1,000 monthly O&M cost per FTE.
- $100K for FLIR Camera Cost.
- $125K for Additional Tools for Visual Inspection.

Part 5. Cost Effectiveness/Benefits

Historical Achieved-Cost Effectiveness Calculations (2018-2022) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits
$937	$934	$910

Forecast of Cost Effectiveness Calculations (2025-2030) ($/MCF)

Standard Cost Effectiveness	With Cap and Trade Cost Benefits	With Cap and Trade, and Social Cost of Methane Cost Benefits
$921	$918	$894

Part 6. Supplemental Information/Documentation

Attachment 24A: Historical Project Schedule for Storage Aboveground Leak Survey

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practices:

Best Practice 19: Above Ground Leak Surveys
Utilities shall conduct frequent leak surveys and data collection at above ground transmission and high-pressure distribution (above 60 psig) facilities including Compressor Stations, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R above ground and pressures above 300 psig only). At a minimum, above ground leak surveys and data collection must be conducted on an annual basis at compressor stations and gas storage facilities.
Best Practice 21: Find It, Fix It
Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event, more than three (3) years after discovery. Utilities may make reasonable exceptions for leaks that are costly to repair relative to the estimated size of the leak.

Historic Project Achievements:

In the 2018 Compliance Plan, SoCalGas requested and was approved funding to repair its above ground (AG) minor leak inventory. In October 2018, this inventory included roughly 5,400 AG minor leaks. In 2019, SoCalGas repaired approximately 5,000 of these AG minor leaks. In March of 2020, SoCalGas completed mitigating approximately 400 leaks to reduce SoCalGas existing inventory to zero. For the rest of 2020, SoCalGas worked on mitigating leaks within six (6) months of detection.

In addition to reducing the AG minor leak inventory in 2020, SoCalGas updated its Gas Standard 223.0126. *Above Ground Leakage Classification and Mitigation Schedules,* for AG minor leaks. Previously, Operations had the flexibility to repair AG minor leaks when it was practical to do so. Gas Standard 223.0126 was revised in 2020 requiring AG minor leaks discovered by Distribution to be classified as "AG Non-Hazardous" leaks and to be repaired in a time frame of ten (10) days to six (6) months, depending on the leak proximity to a building. Distribution no longer classifies above ground leaks as AG minor at the time of detection.

In 2021, SoCalGas continued the efforts of repairing AG Non-Hazardous leaks within six (6) months of detection and not having an inventory by that year's end. To support these leak repair efforts, SoCalGas used incremental field employees discussed in Chapters 1 and 2 to manage the AG Non-Hazardous inventory.

Emission Reductions Achieved

Emission reductions achieved vary depending on the emission factor used, and therefore, are not included in the Annual Emissions Report.

Cost Effectiveness Evaluation on Historic Work

Historical cost effectiveness was not evaluated for the 2024 Compliance Plan because SoCalGas did not request any additional funding for the program since the 2018 Compliance Plan submittal.

Part 2. Proposed New or Continuing Measure

SoCalGas has completed the project objectives and will not propose new or continuing measures.

Part 3. Abatement Estimates

There are no abatement estimates because SoCalGas will not pursue measures in this Compliance Period.

Part 4. Cost Estimates

SoCalGas will not request funds for this initiative in this Compliance Period.

Part 5. Cost Effectiveness/Benefits

Cost effectiveness cannot be calculated because SoCalGas will not request funding for this Chapter during this Compliance Period.

Part 6. Supplemental Information/Documentation

Attachment 25A: Historical Project Schedule for Distribution Above Ground Leak Repair

Chapter 26: High Bleed Device Replacement

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice(s):

Best Practice 23: Minimize Emissions from Operations, Maintenance and Other Activities
Utilities shall minimize emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high bleed pneumatic devices with technology that does not vent gas (i.e. no-bleed) or vents significantly less natural gas (i.e. low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

Historic Project Achievements:

Since 1993, SoCalGas has been addressing the replacement of high-bleed pneumatic devices through the EPA Natural Gas STAR[1] Best Practice (BP). Pneumatic devices powered by pressurized natural gas are used widely in the natural gas industry as pressure regulators and valve controllers. Emission reductions are achieved by replacing high-bleed devices with low-bleed devices, retrofitting high-bleed devices, and improving maintenance practices. Individual savings have varied depending on the design, condition, and specific operating conditions of the controller.

Pneumatic devices come in three (3) basic designs:

1. Continuous bleed devices are used to modulate pressure and generally vent gas at a steady rate.
2. Actuating or intermittent bleed devices perform snap-acting control and release gas only when they stroke a valve open or closed or as they throttle gas flows.
3. Self-contained devices release gas into the downstream pipeline, not to the atmosphere.

Emission reductions from pneumatic devices were pursued by the following options, either alone or in combination:

- Replacement of high-bleed devices with low-bleed devices having similar performance capabilities.
- Installation of low bleed retrofit kits on operating devices.
- Enhanced maintenance, cleaning and tuning, repairing/replacing leaking gaskets, tubing fittings, and seals.

In the 2018 Compliance Plan, SoCalGas was approved to remove the eight (8) remaining High Bleed Pneumatic Devices found in operation and, as of 2020, have been removed or replaced. In 2021, no new devices were identified, removed, or replaced from the system. No incremental staffing was required to implement this measure.

[1] Natural Gas STAR Program | US EPA: https://www.epa.gov/natural-gas-star-program/natural-gas-star-program

Emission Reductions Achieved:

The estimated emission reductions achieved were 1,337 MCF for the calendar years 2018 and 2019, and 1,500 MCF for the calendar year 2020. Emissions from high bleed pneumatic devices were captured in population-based emission factors as part of a broader emission source category. As such, there is no separate baseline for high bleed pneumatic devices and the reductions were not captured in the 2021 and 2022 Annual Emissions Reports.

Historical Emission Reductions (MCF)

2018	2019	2020
1,337	1,337	1,500

Cost Effectiveness Evaluation on Historic Work:

Historical cost effectiveness was not evaluated for the 2020 Compliance Period because SoCalGas did not request any additional funding for this program.

Part 2. Proposed New or Continuing Measure

SoCalGas has completed the project objectives and will not propose new or continuing measures.

Part 3. Abatement Estimates

There are no abatement estimates because SoCalGas will not pursue measures in this Chapter in this Compliance Period.

Part 4. Cost Estimates

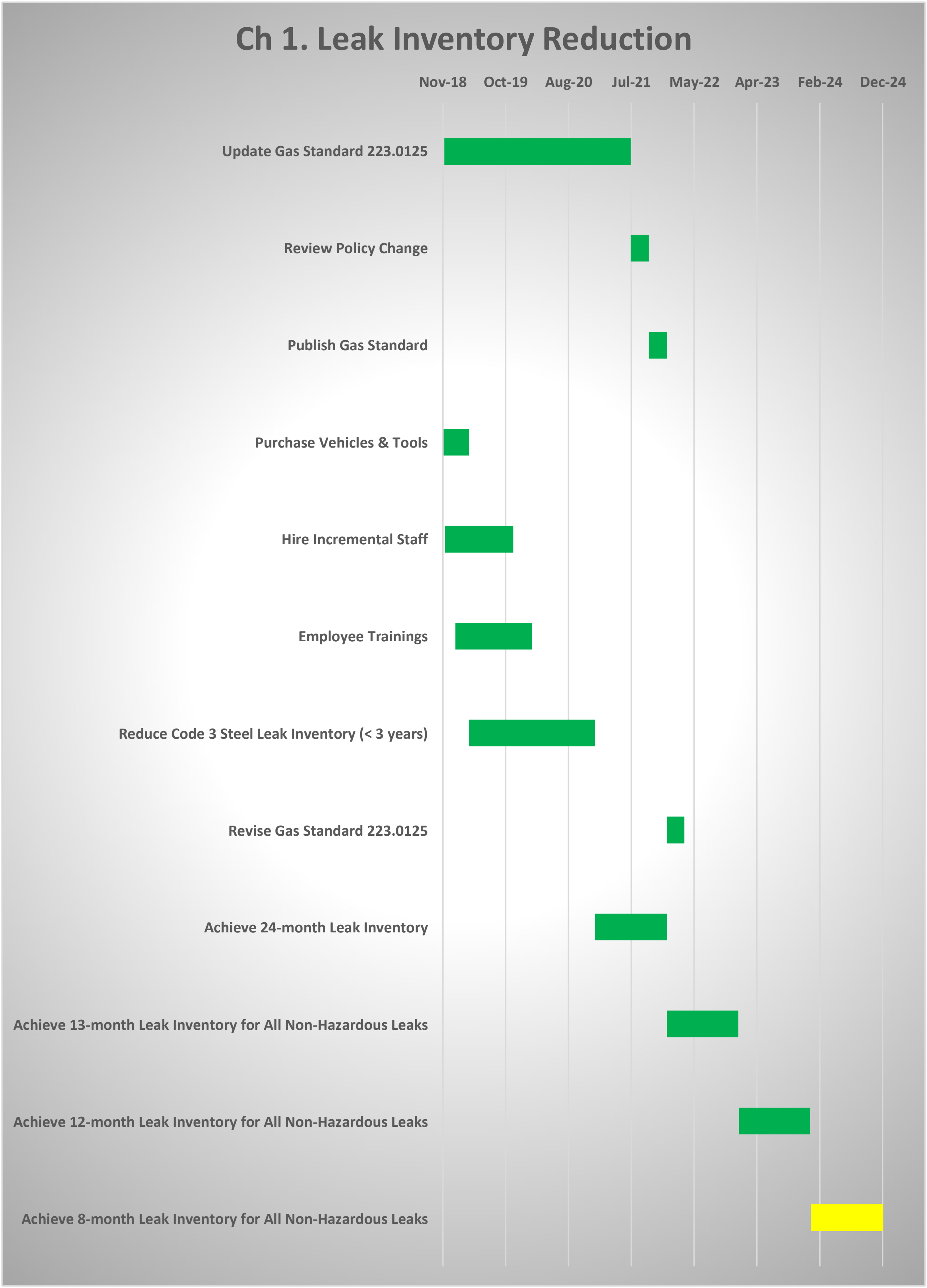
SoCalGas will not request funds for this initiative in this Compliance Period.

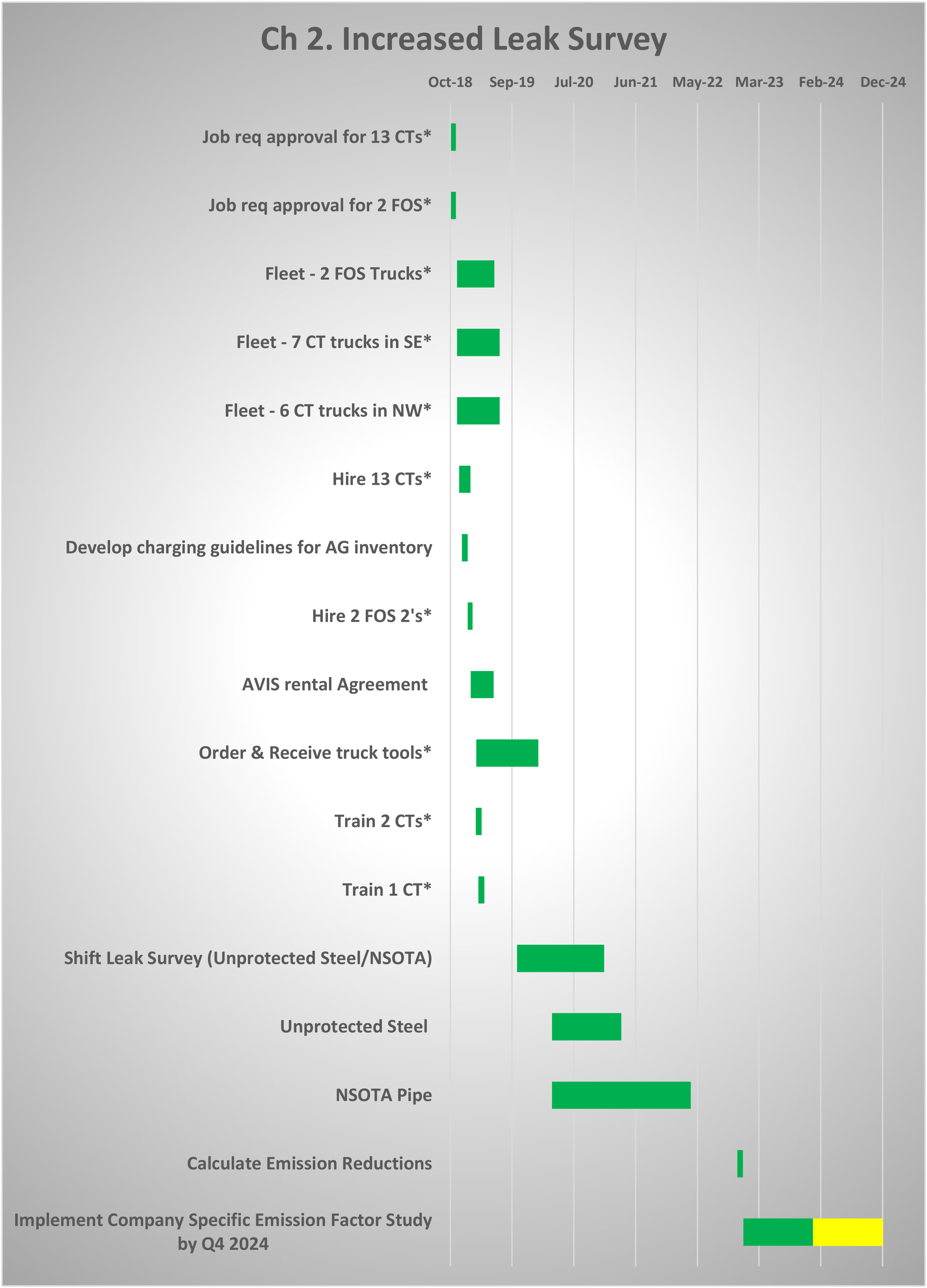
Part 5. Cost Effectiveness/Benefits

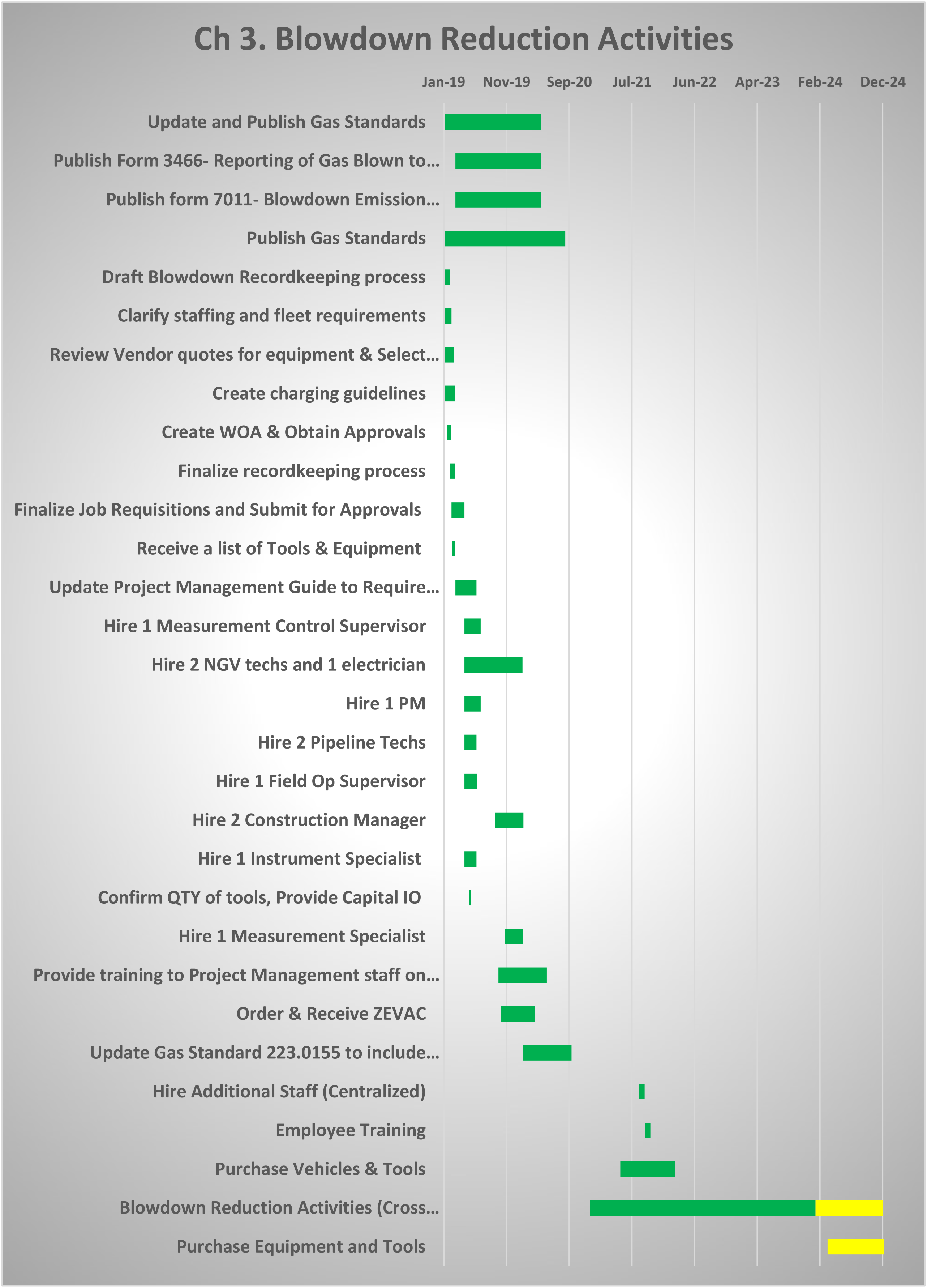
Cost effectiveness cannot be calculated because SoCalGas will not request funding for this Chapter during this Compliance Period.

Part 6. Supplemental Information/Documentation

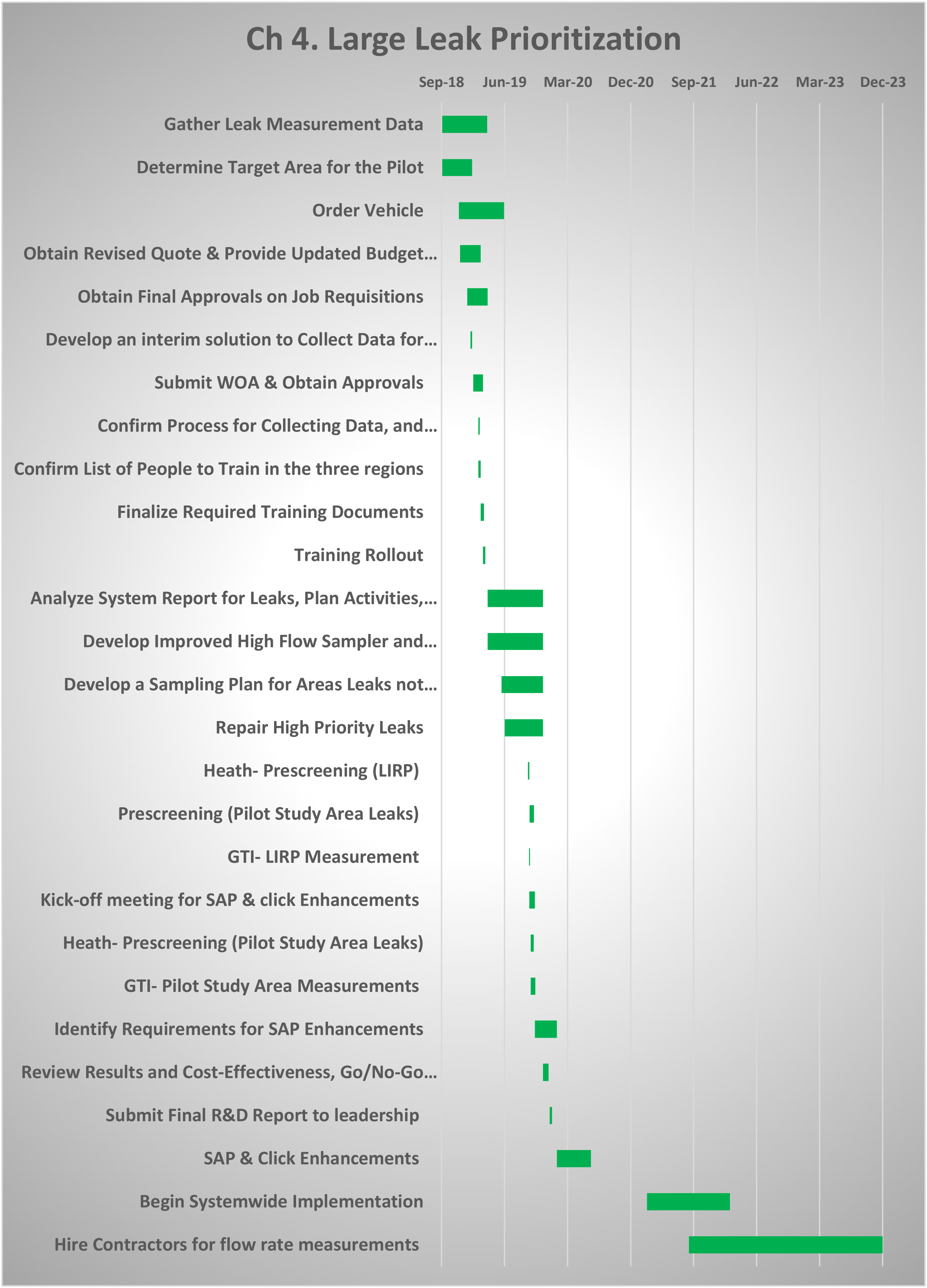
Attachment 26A: Historical Project Schedule for High Bleed Device Replacement


Ch 1. Leak Inventory Reduction
Nov-18
Oct-19
Aug-20
Jul-21
May-22
Apr-23
Feb-24
Dec-24
Update Gas Standard 223.0125
Review Policy Change
Publish Gas Standard
Purchase Vehicles & Tools
Hire Incremental Staff
Employee Trainings
Reduce Code 3 Steel Leak Inventory (< 3 years)
Revise Gas Standard 223.0125
Achieve 24-month Leak Inventory
Achieve 13-month Leak Inventory for All Non-Hazardous Leaks
Achieve 12-month Leak Inventory for All Non-Hazardous Leaks
Achieve 8-month Leak Inventory for All Non-Hazardous Leaks


Ch 2. Increased Leak Survey
Oct-18
Sep-19
Jul-20
Jun-21
May-22
Mar-23
Feb-24
Dec-24
Job req approval for 13 CTs*
Job req approval for 2 FOS*
Fleet - 2 FOS Trucks*
Fleet - 7 CT trucks in SE*
Fleet - 6 CT trucks in NW*
Hire 13 CTs*
Develop charging guidelines for AG inventory
Hire 2 FOS 2's*
AVIS rental Agreement
Order & Receive truck tools*
Train 2 CTs*
Train 1 CT*
Shift Leak Survey (Unprotected Steel/NSOTA)
Unprotected Steel
NSOTA Pipe
Calculate Emission Reductions
Implement Company Specific Emission Factor Study by Q4 2024

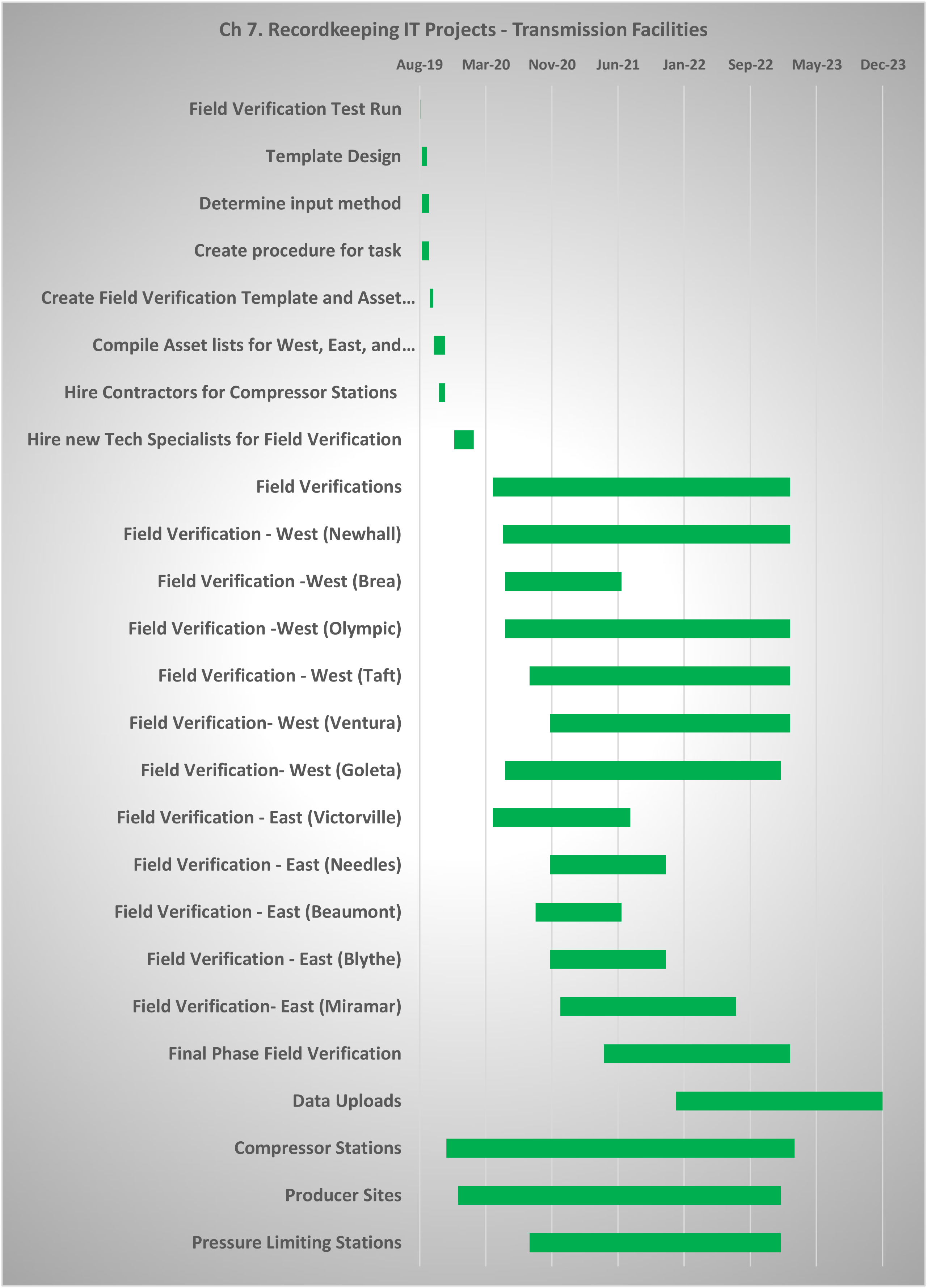

Ch 3. Blowdown Reduction Activities
Jan-19
Nov-19
Sep-20
Jul-21
Jun-22
Apr-23
Feb-24
Dec-24
Update and Publish Gas Standards
Publish Form 3466- Reporting of Gas Blown to...
Publish form 7011- Blowdown Emission...
Publish Gas Standards
Draft Blowdown Recordkeeping process
Clarify staffing and fleet requirements
Review Vendor quotes for equipment & Select...
Create charging guidelines
Create WOA & Obtain Approvals
Finalize recordkeeping process
Finalize Job Requisitions and Submit for Approvals
Receive a list of Tools & Equipment
Update Project Management Guide to Require...
Hire 1 Measurement Control Supervisor
Hire 2 NGV techs and 1 electrician
Hire 1 PM
Hire 2 Pipeline Techs
Hire 1 Field Op Supervisor
Hire 2 Construction Manager
Hire 1 Instrument Specialist
Confirm QTY of tools, Provide Capital IO
Hire 1 Measurement Specialist
Provide training to Project Management staff on...
Order & Receive ZEVAC
Update Gas Standard 223.0155 to include...
Hire Additional Staff (Centralized)
Employee Training
Purchase Vehicles & Tools
Blowdown Reduction Activities (Cross...
Purchase Equipment and Tools


Ch 3. Blowdown Reduction Planning Tool
Oct-20
Feb-21
Jul-21
Nov-21
Mar-22
Aug-22
Dec-22
May-23
Project Scope Development
SharePoint Form Development
Workflow Development
Process Testing
Tranmission Process Integratoin
Finalize Process Testing
Training Development
Update & Publish Gas Standards
Training Delivery


Ch 4. Large Leak Prioritization
Sep-18
Jun-19
Mar-20
Dec-20
Sep-21
Jun-22
Mar-23
Dec-23
Gather Leak Measurement Data
Determine Target Area for the Pilot
Order Vehicle
Obtain Revised Quote & Provide Updated Budget…
Obtain Final Approvals on Job Requisitions
Develop an interim solution to Collect Data for…
Submit WOA & Obtain Approvals
Confirm Process for Collecting Data, and…
Confirm List of People to Train in the three regions
Finalize Required Training Documents
Training Rollout
Analyze System Report for Leaks, Plan Activities,…
Develop Improved High Flow Sampler and…
Develop a Sampling Plan for Areas Leaks not…
Repair High Priority Leaks
Heath- Prescreening (LIRP)
Prescreening (Pilot Study Area Leaks)
GTI- LIRP Measurement
Kick-off meeting for SAP & click Enhancements
Heath- Prescreening (Pilot Study Area Leaks)
GTI- Pilot Study Area Measurements
Identify Requirements for SAP Enhancements
Review Results and Cost-Effectiveness, Go/No-Go…
Submit Final R&D Report to leadership
SAP & Click Enhancements
Begin Systemwide Implementation
Hire Contractors for flow rate measurements


Ch 5. Damage Prevention Algorithm & Proactive Intervention
Jan-19
Sep-19
May-20
Dec-20
Aug-21
Apr-22
Dec-22
Develop a Methodology for Risk Ranking one call...
Develop & Test the Algorithm
Research Vendors
SoCalGas Agreement with Urbint
Phase I- Project Kickoff
Phase I- Gather Data
Model Training
Preliminary Analysis Presentation
On-the-ground Validation Kick-off
Mid-Validation Sync & No-call In Analysis...
Phase 2- Initial Model Creation (phase 2)
Initial Model Results Delivery (Phase 2)
Iteration & Validation of AI model (phase 3)
Final Presentation (phase 3)
Expanded standby at medium pressure systems...
Evaluate pilot results
Hire and train incremental FTEs
Update gas standards
Implement expanded standby program on...
Hire and train incremental FTEs
On-going analysis and evaluating model
Test and validate model
Develop Process for identifying repeat offenders
New Model into Production
On-going analysis and evaluating model
Evaluate Results
Propose Changes
Calculate Emission Reductions


Ch 6. Advanced Meter Analytics
Apr-21
Jul-21
Nov-21
Mar-22
Jun-22
Oct-22
Feb-23
May-23
Release # R1
Labeling of consumption patterns for training...
Training models on 800 accounts with...
Deployment of 61 Machine Learning models
Deployment of ESSM application V1.0
Release # R6
Implemented post processing processes to...
Implemented monitoring and alerting...
Enhanced performance to handle data growth...
Deployment of ESSM Dashboard (visualization...
Deployment of ESSM application V2.0
Release # R13
Implemented code cleanup and code standards
Developed and deployed thresholding...
Enhanced dashboard performance
Release # TBD
Generate new labeled dataset for retraining of...
Enhance current clustering model to reduce...
Implement feedback loop in ESSM dashboard...
Release # TBD
Perform retraining on all 61 models by...
Evaluate and deploy Machine Learning models...
Implement metric evaluation in ESSM...
Release # TBD
Develop automated processes to expedite...
Develop automated processes to improve the...
Develop reports on model metrics, accuracy...
Release # TBD
Generate new labeled dataset for retraining of...
Develop automatic processes to expedite the...
Evaluate and improve model performance with...


Ch 7. Recordkeeping IT Projects - Transmission Facilities
Aug-19
Mar-20
Nov-20
Jun-21
Jan-22
Sep-22
May-23
Dec-23
Field Verification Test Run
Template Design
Determine input method
Create procedure for task
Create Field Verification Template and Asset…
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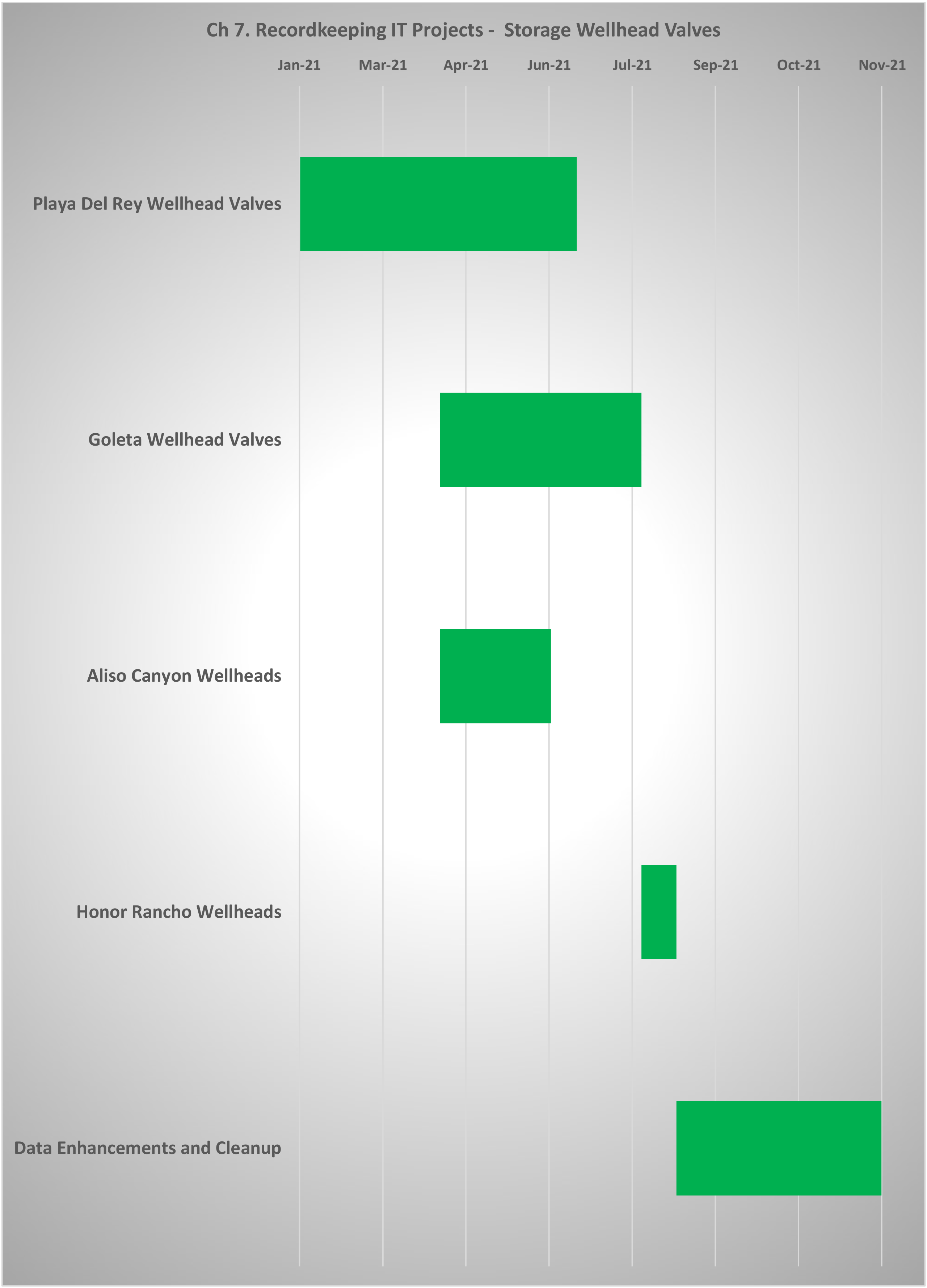
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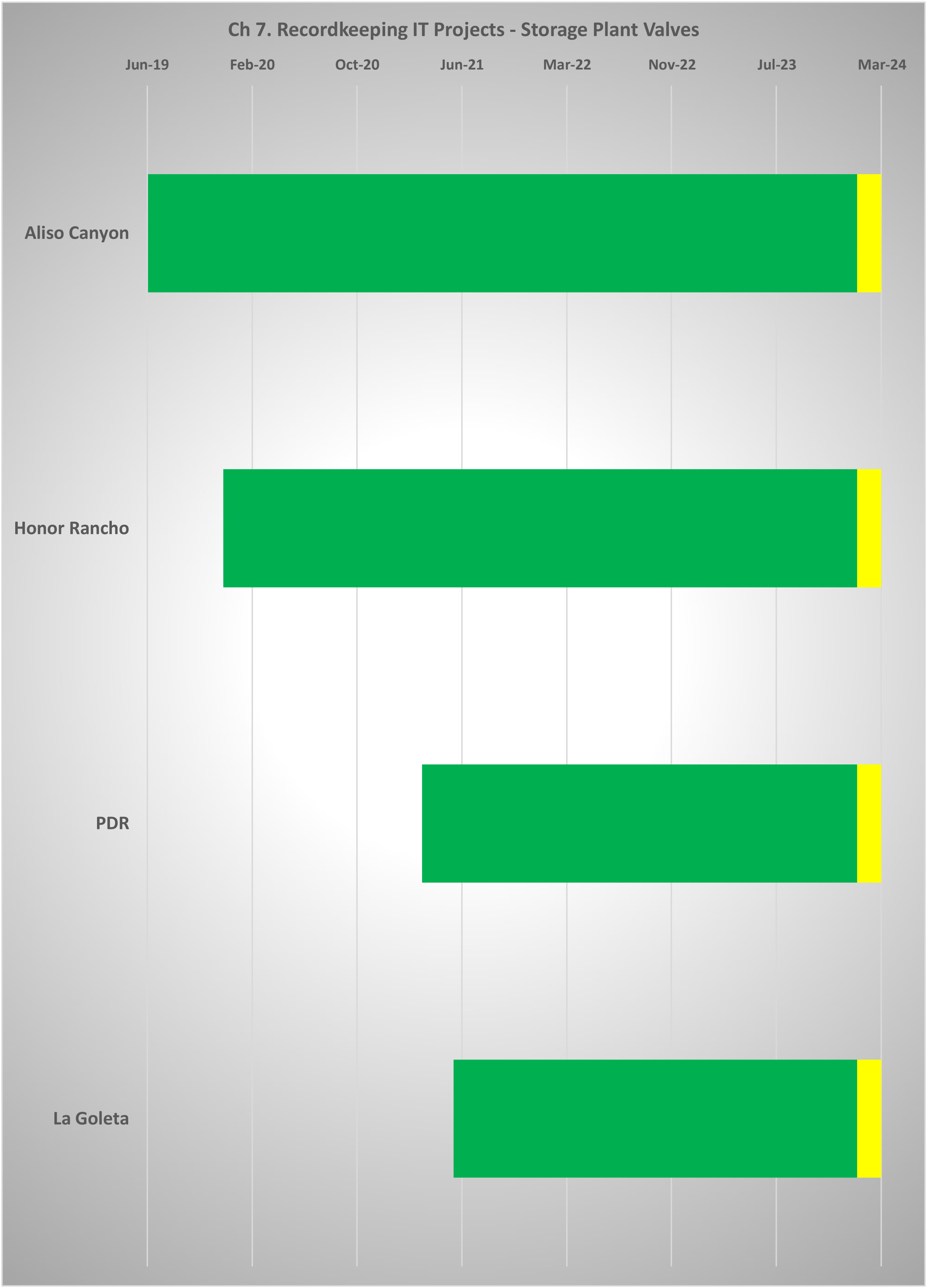
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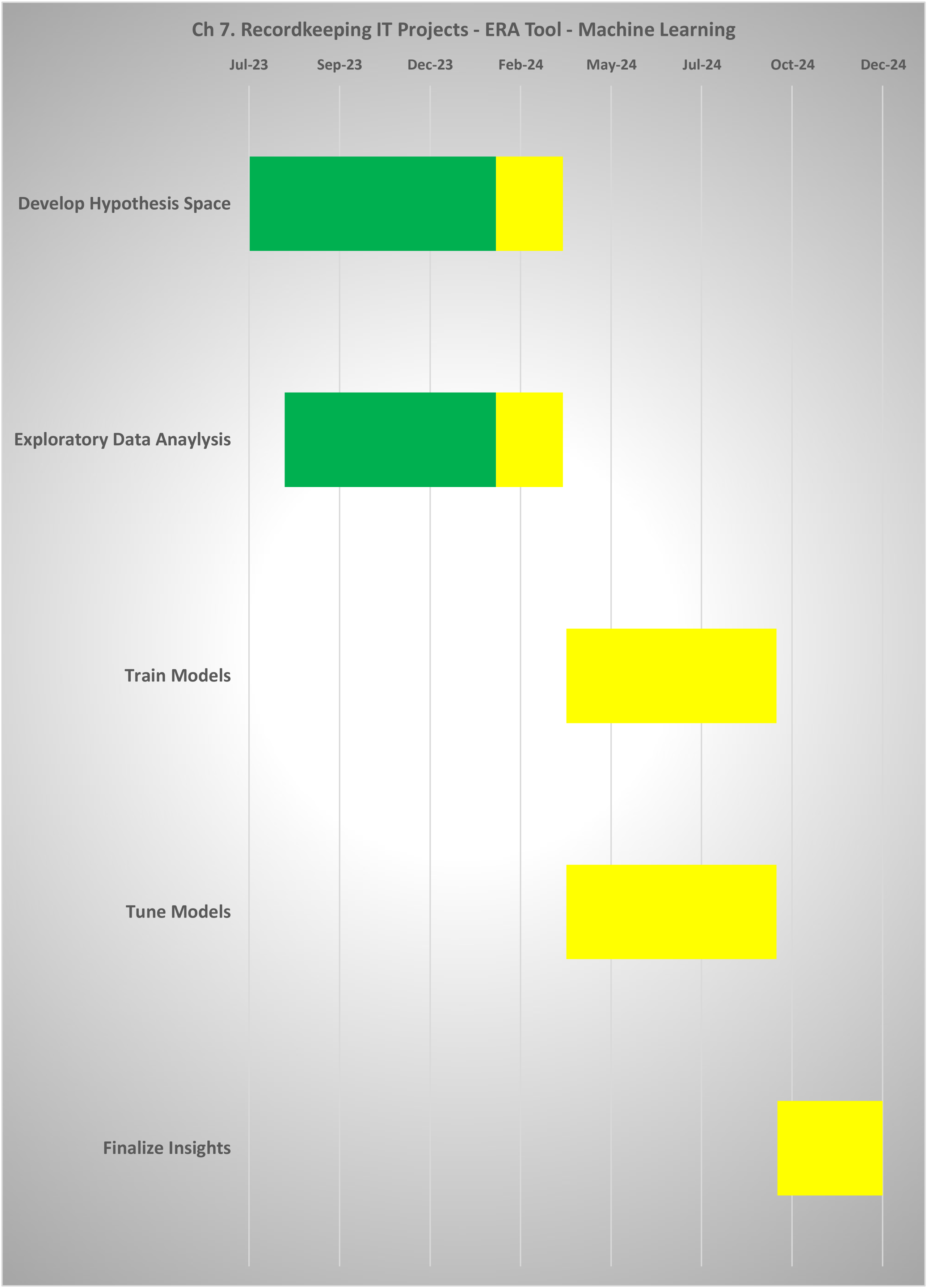
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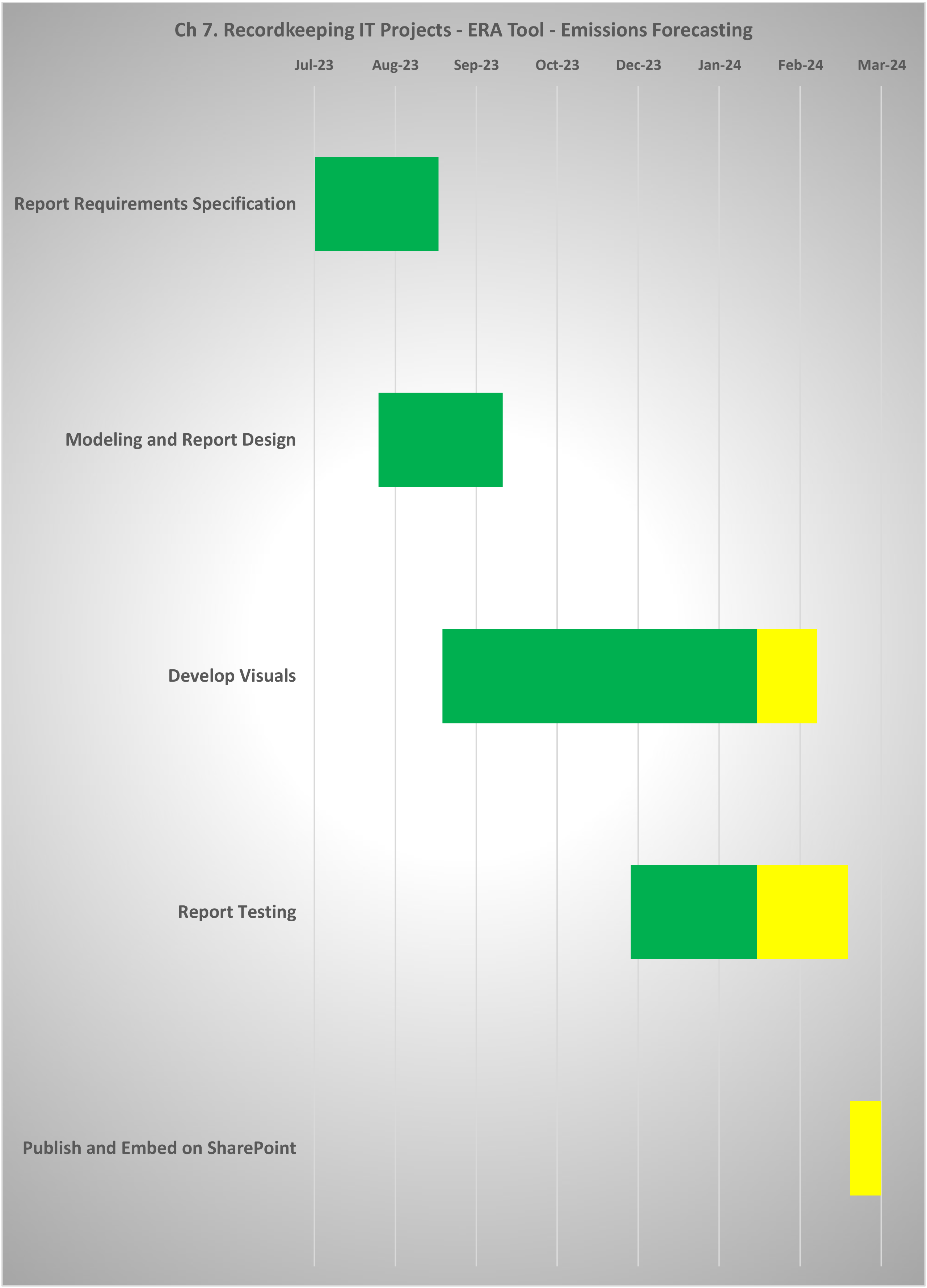
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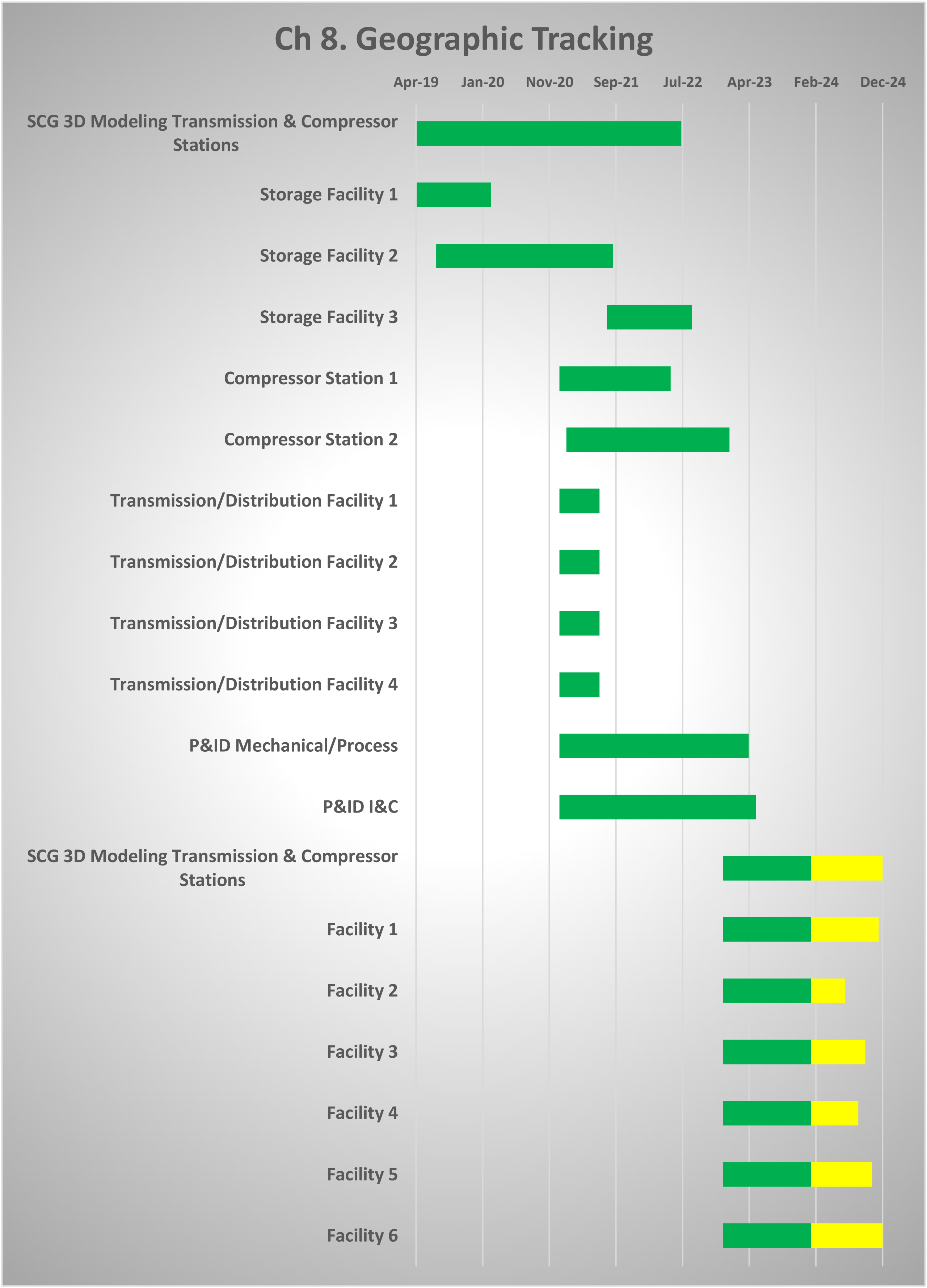
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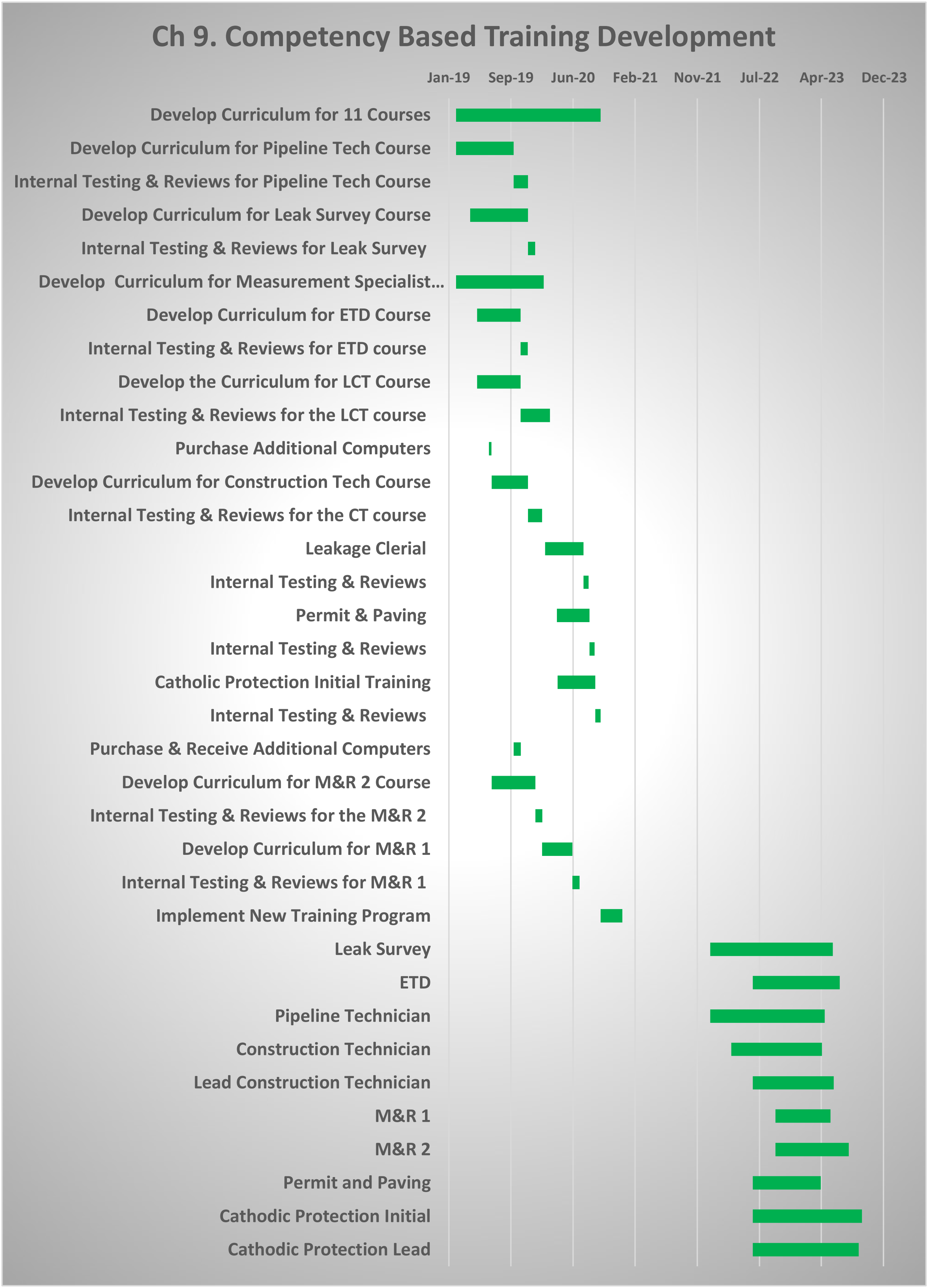
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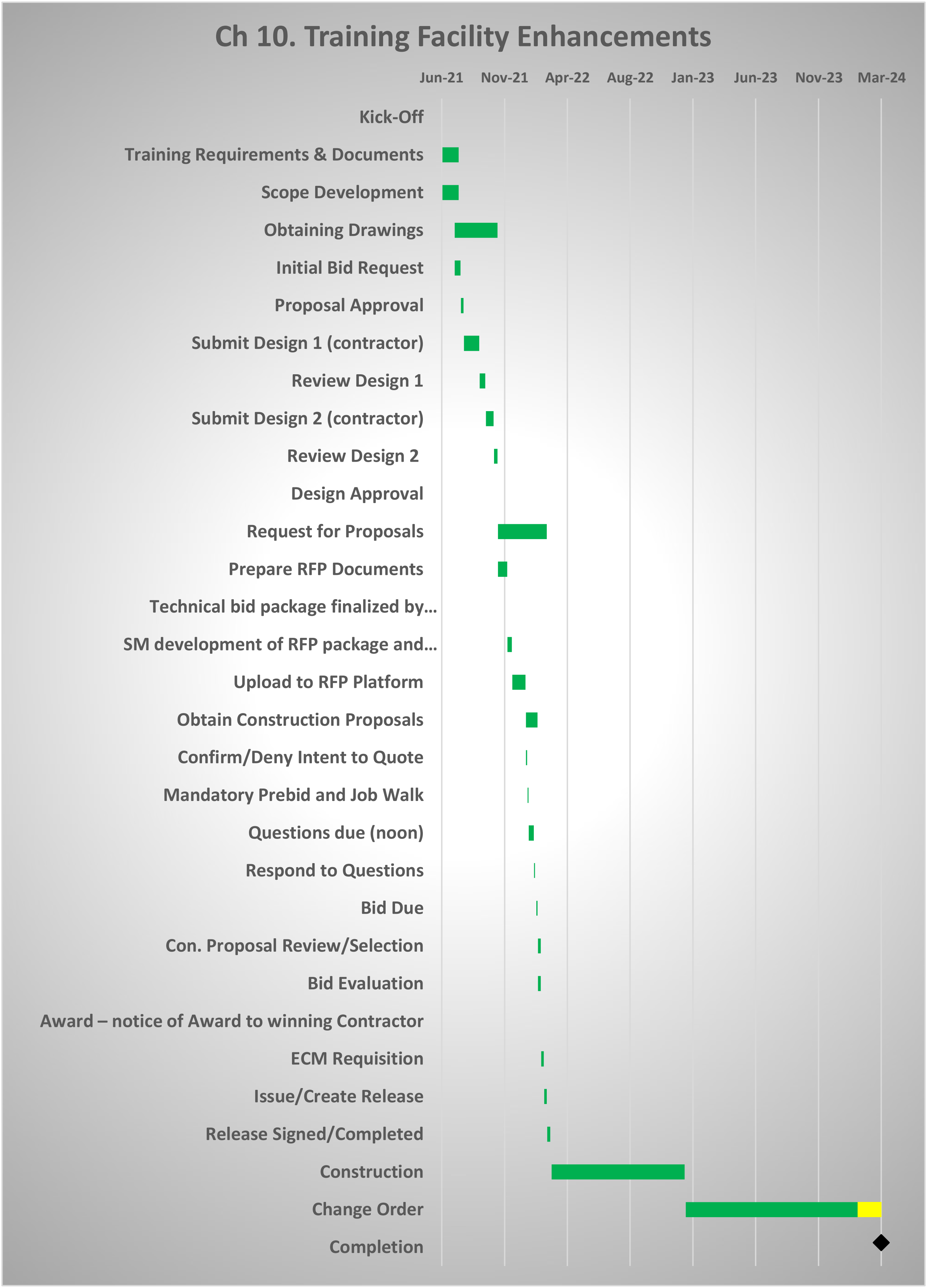
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Release Signed/Completed
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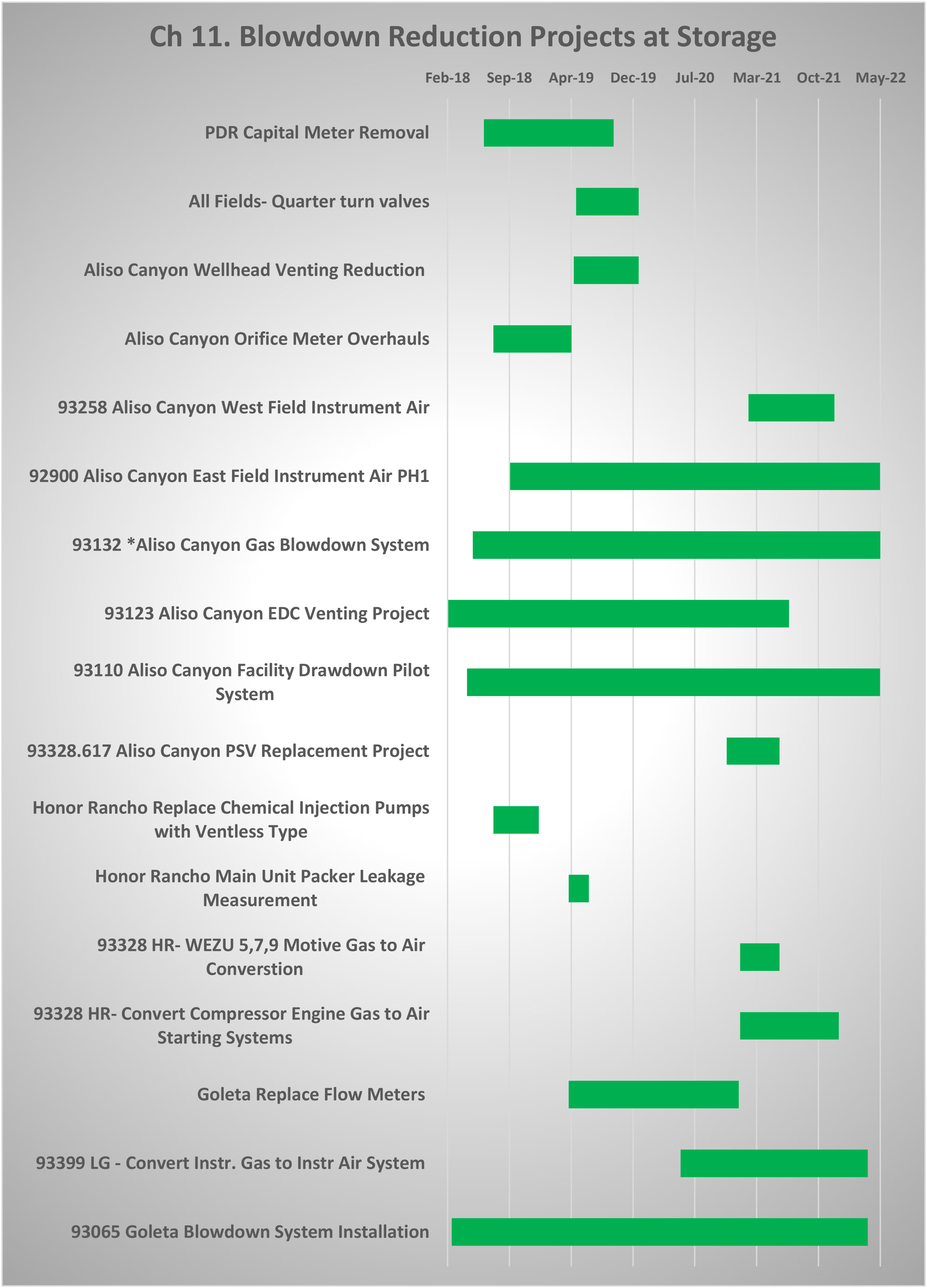
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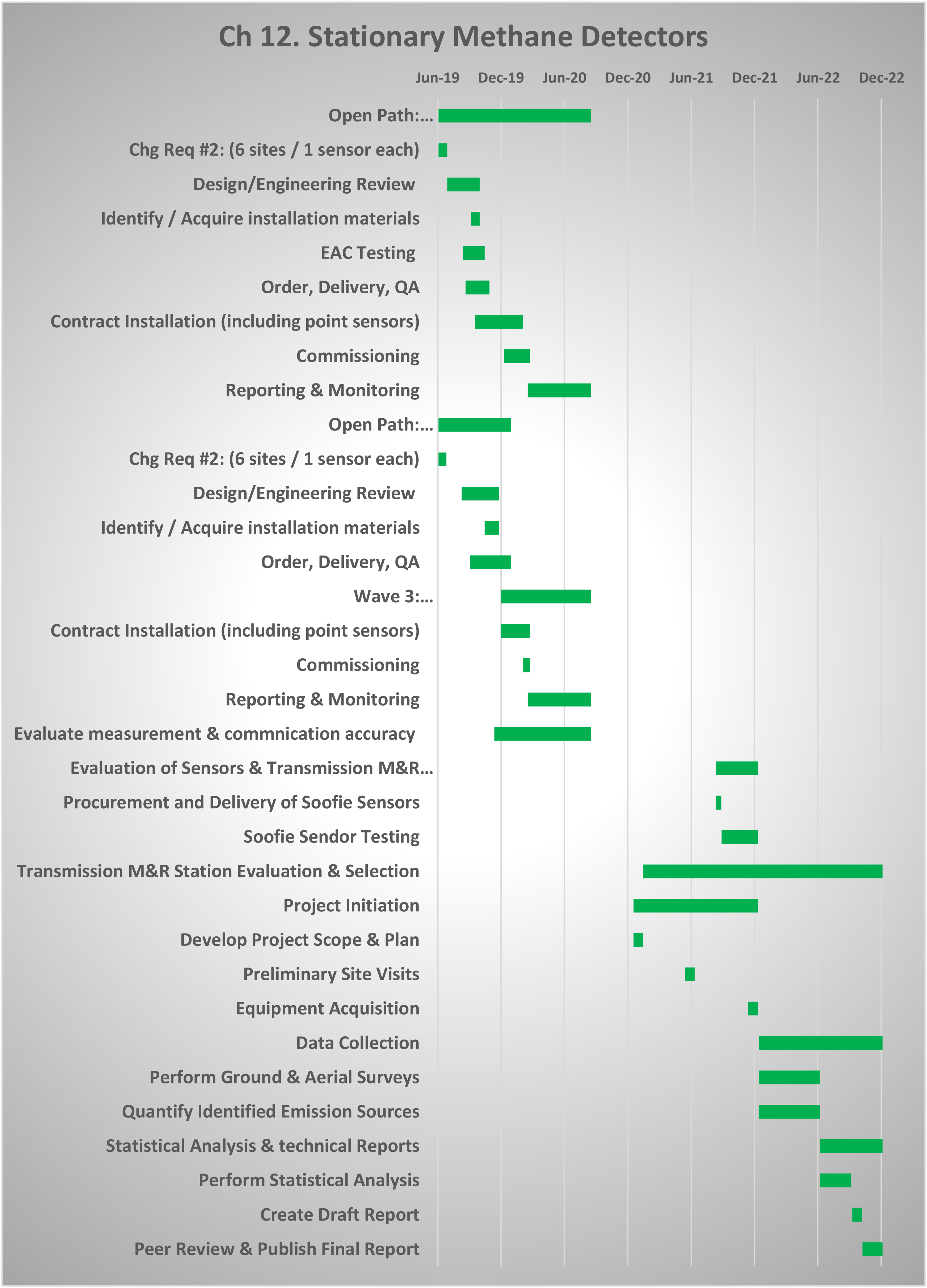
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Commissioning
Reporting & Monitoring
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Order, Delivery, QA
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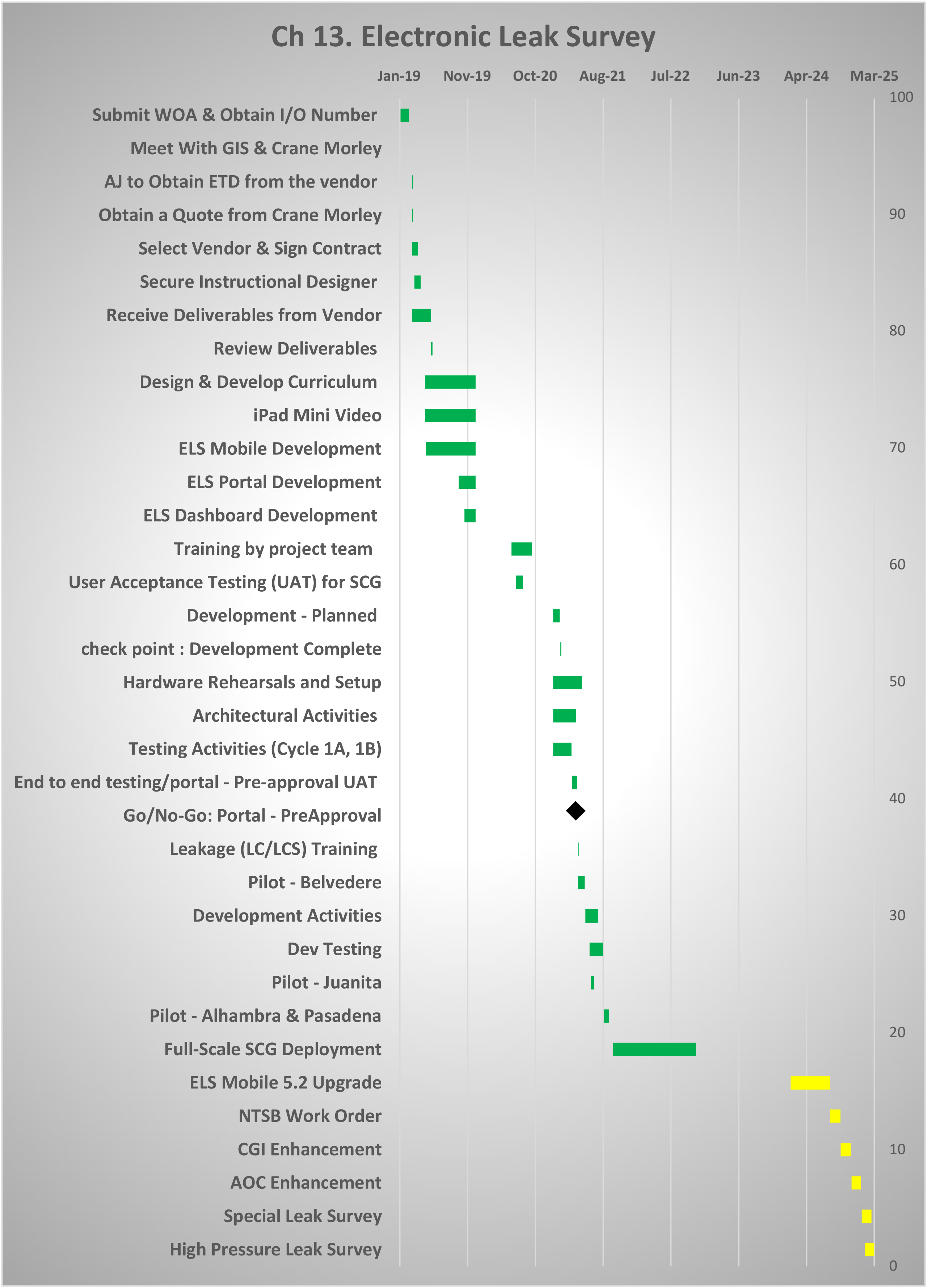
Perform Statistical Analysis
Create Draft Report
Peer Review & Publish Final Report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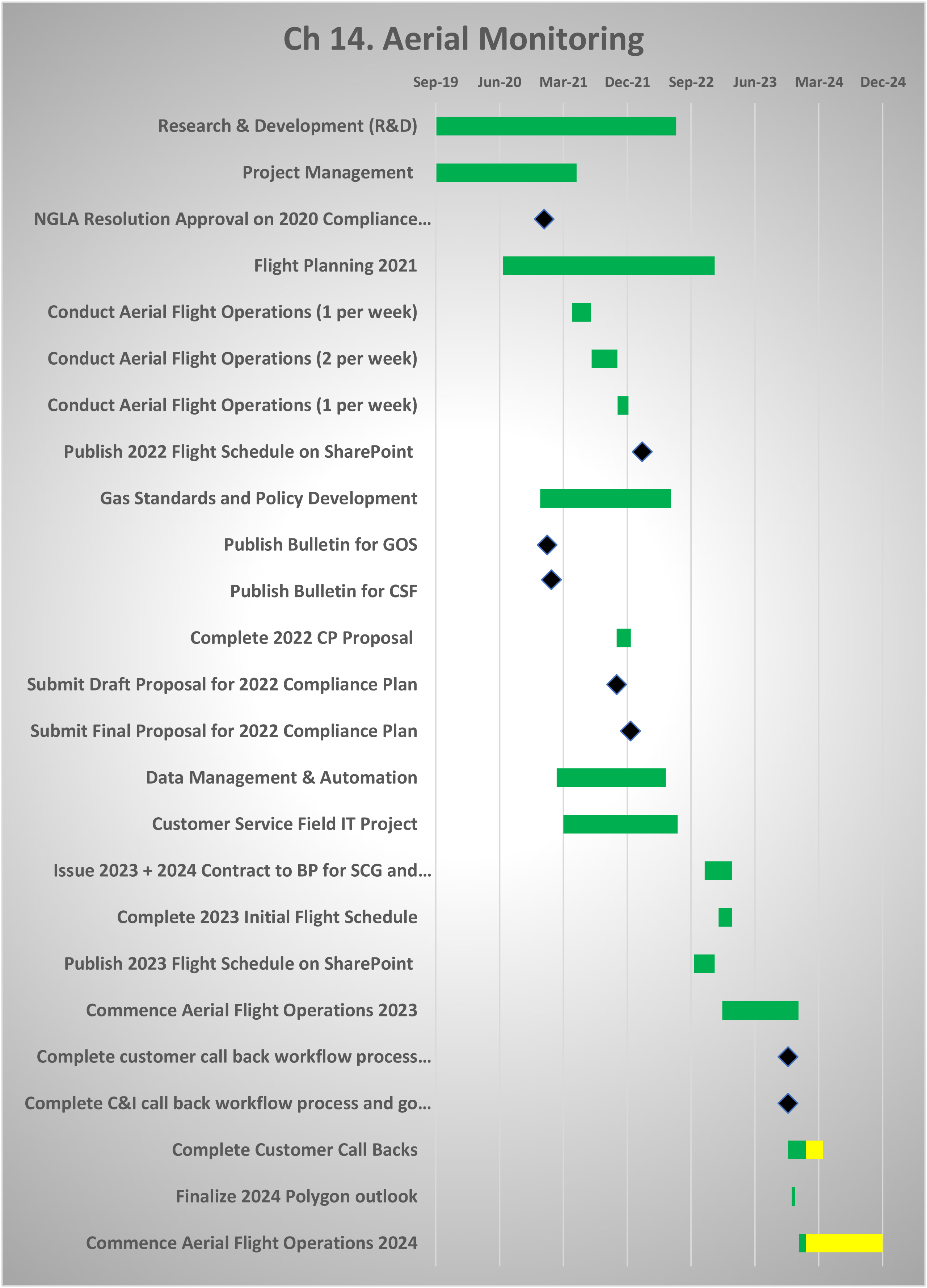
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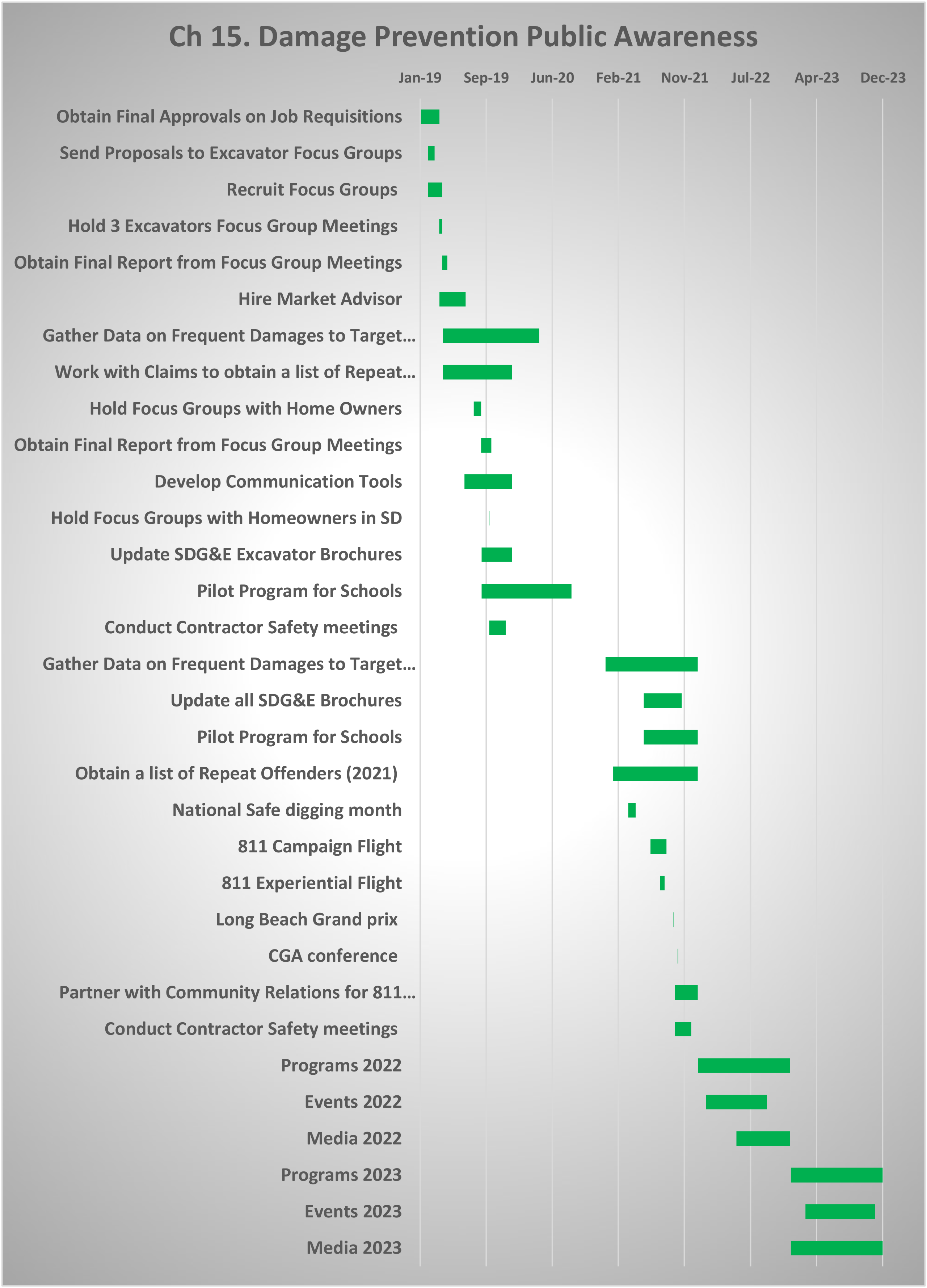
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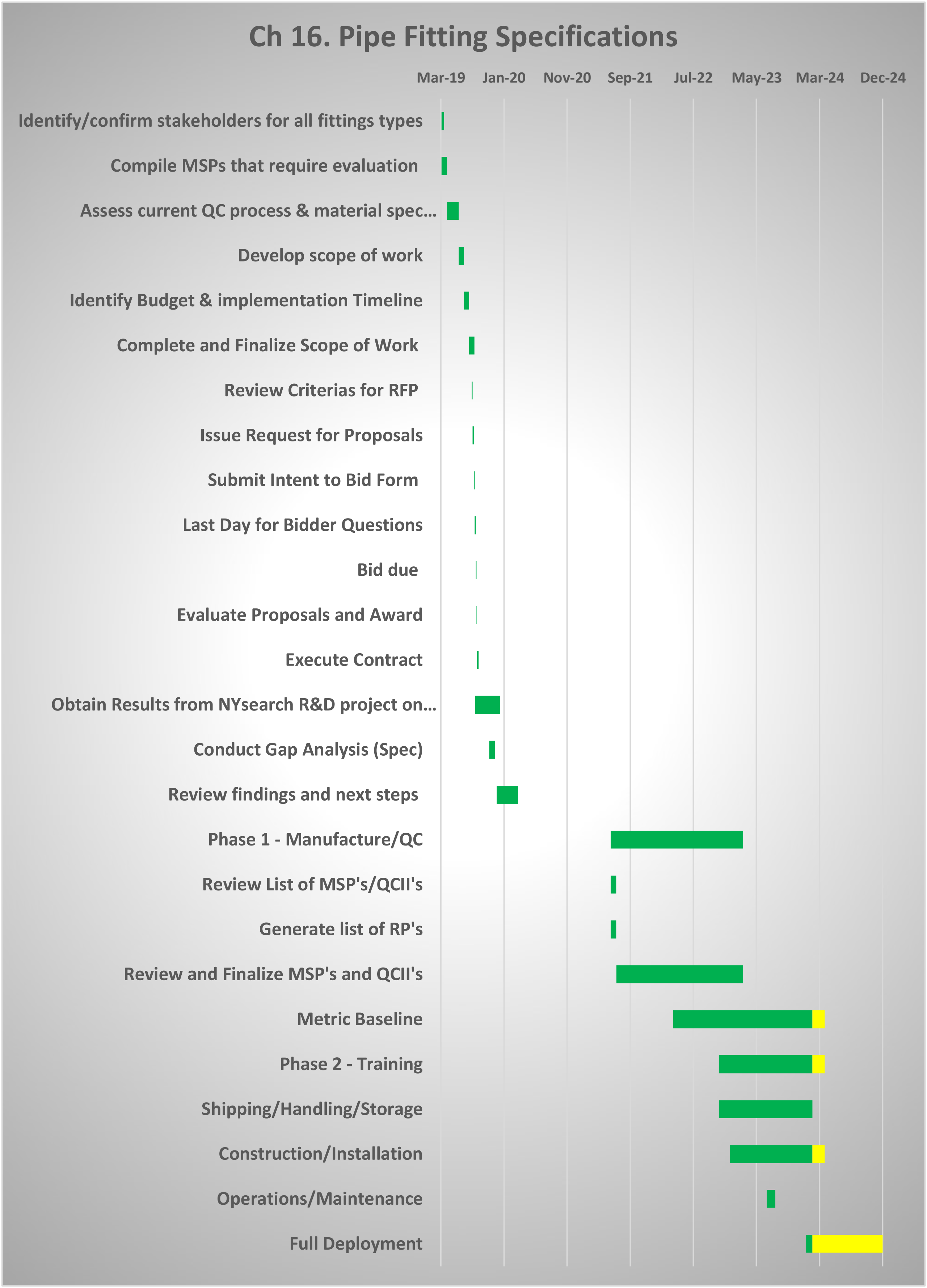
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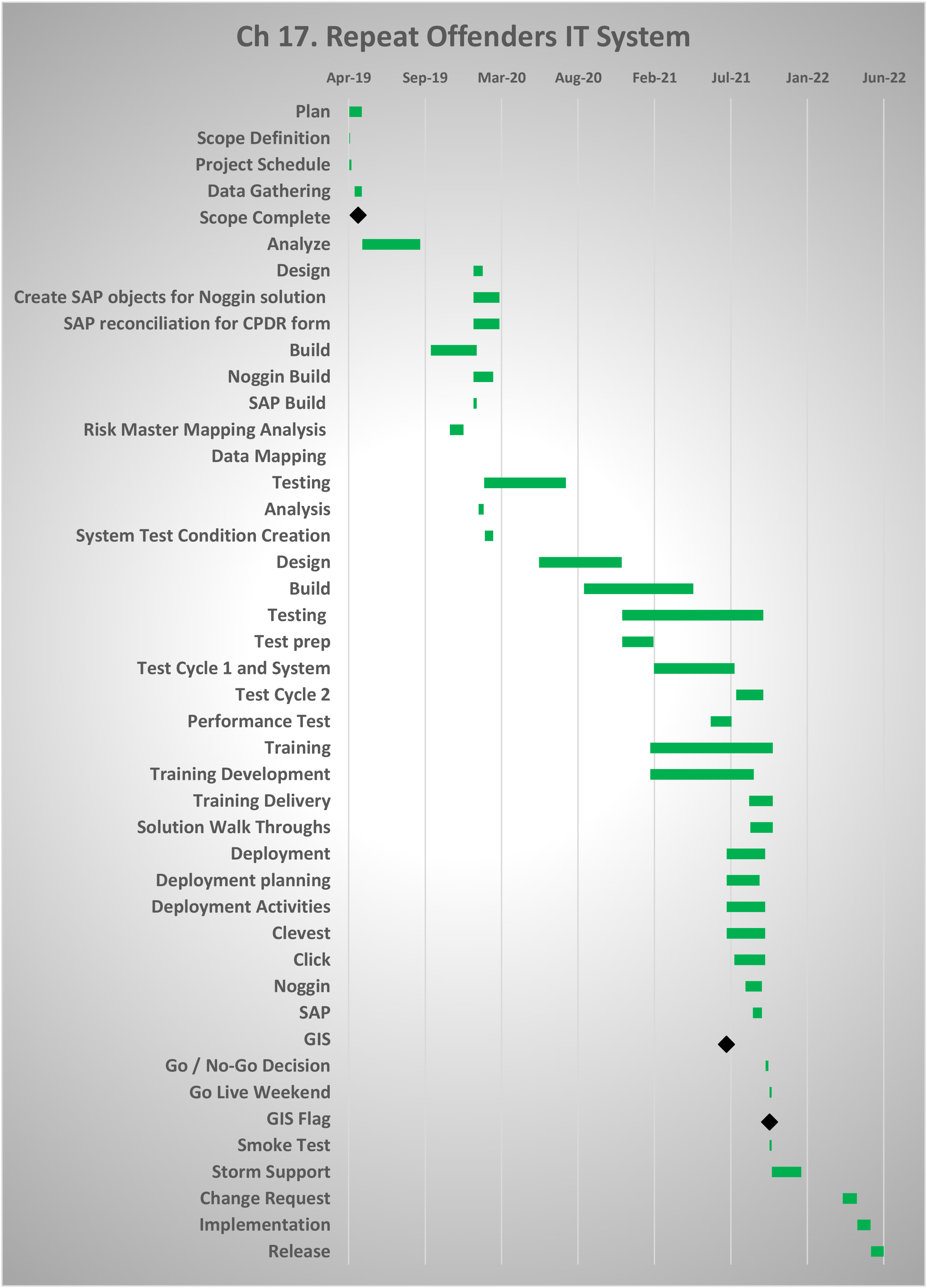
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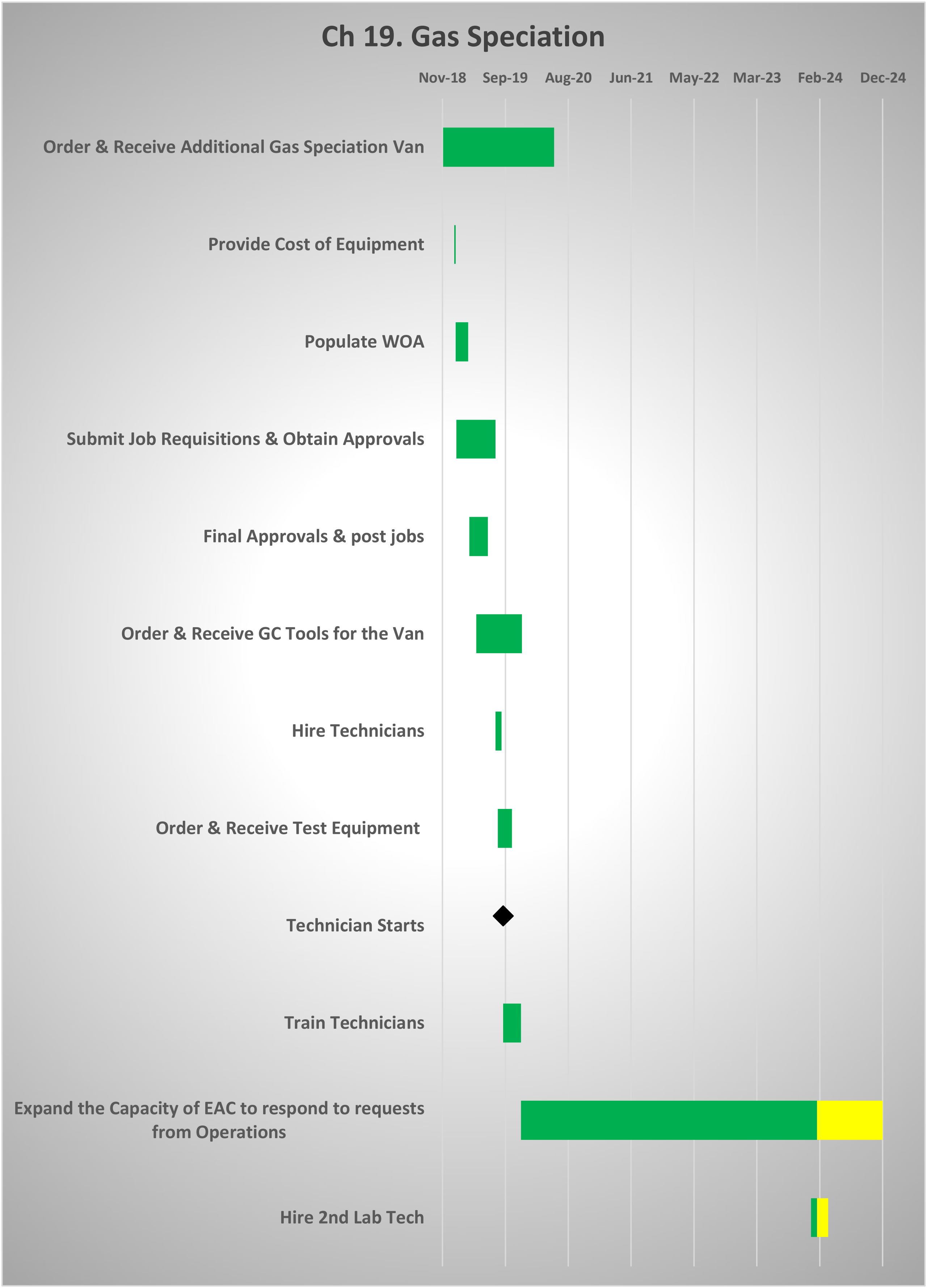
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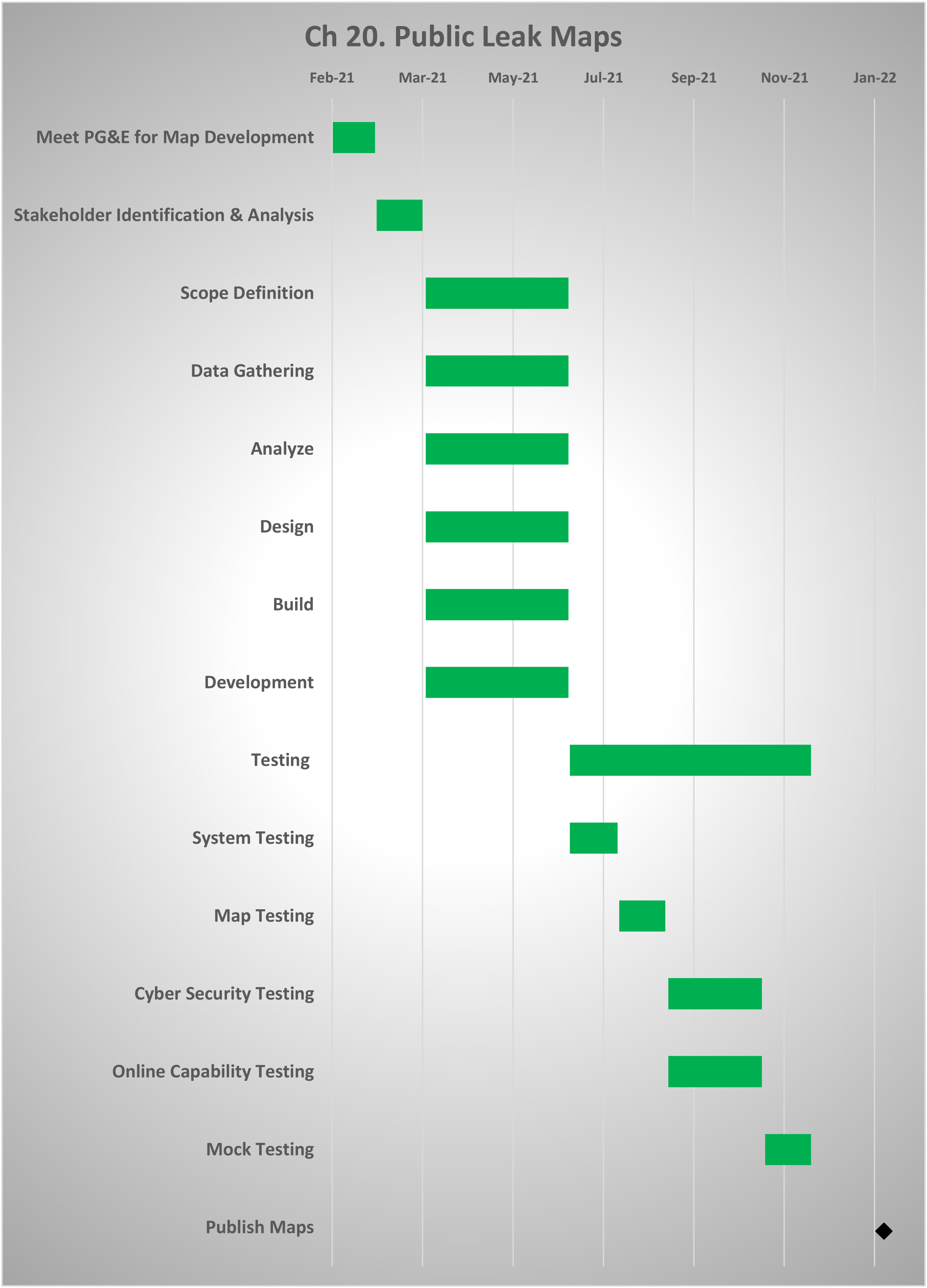
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Technology for Energy Pipelines

COST EFFECTIVE LEAK MITIGATION AT NATURAL GAS TRANMISSION COMPRESSOR STATIONS
PR- 246-9526

Prepared for the
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Prepared by the following Research Agency:

Indaco Air Quality Services, Inc

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Executive Summary

This report describes a cooperative study sponsored by PRC International (PRCI), the Gas Research Institute (GRI), and the U.S. Environmental Protection Agency (EPA) to determine the most cost effective ways to mitigate leaks at natural gas compressor stations. Leak rate measurements were initially made at thirteen compressor stations starting in September of 1995 until the end of 1997. Ten of these sites were selected for four quarters of surveys. This report presents the emission factors for natural gas compressor stations, the trends in leak rates over time, and a cost benefit analysis of leak mitigation.

A total of 34,400 components were surveyed at the thirteen facilities. The total leak rate from initial measurements conducted at the 13 sites was 536,100 Mcf/yr; at $2/Mcf this is equivalent to $1,072,2OO/yr. The largest total leak rate from an individual site was 200,000 Mcf/yr ($400,000 at $2/Mcf) which accounted for 37% of the total leak rate from all sites. The largest source at this site was venting from the power gas system used to control compressor unloaders (142,000 Mcf/yr). This was not a significant source at other sites.

The top 10% of leaking components from all sites accounted for 91% of the total leakage. Leakage from standard components (such as valves, flanges, and threaded fittings) accounted for 20% of the total leak rate, leakage from the rod packings on reciprocating compressors accounted for 38%, and leakage from other vented components accounted for 42% of the total leakage.

EPA Method 21 was not found to be a cost effective method for determining leak rates because the uncertainties can be over a factor of 1000. Leak detection can be accomplished faster and more economically using soap solution and catalytic oxidation/thermal conductivity detectors. Ultrasonic detection may also be useful as a rapid screening method but may miss significant leaks due to noisy backgrounds at the site or due to the large variation of noise levels that different types of leaks may generate.

A reciprocating compressor facility with seven to eight compressors could be expected on average to develop new leakage at standard components of 2,700 Mcf/yr. Approximately 75% of the total new leak volume occurs at compressor components even though they only comprise approximately 30% of the total components at a site. The cost of follow-up surveys can be reduced by focusing on the compressor areas. A centrifugal compressor facility with two compressors could be expected to develop new leakage at standard components of approximately 100 Mcf/yr. The results are indicative of the fact that these facilities do not experience the type of vibrational stresses typically encountered at reciprocating compressor stations.

Measurements of leakage across compressor rod packings made during this and other work indicate that 25% to 33% of rod packings maintain leak rates below 100 Mcf/yr. To maintain leakage less than 100 Mcf/yr may require more rigorous maintenance than is currently applied at many sites. In addition to changing the rod packing, it may be essential to check the surface roughness of the compressor rod and monitor the condition of the packing cup surfaces and rework these as necessary.

If leaks with an estimated payback period of one year or less were repaired (assuming $2/Mcf as the value of gas), the average payback period for the entire maintenance program would have been approximately 4 months and the total leak reduction at the sites would have been 71%. The average net savings per site for the first year would have been $39,500, and for the second year would have been $98,400. If the cost of the leak measurement program were included, the payback period would have been slightly less than 7 months with an average net first year savings of $26,800, and an average net second year savings of $85,600.

When a comprehensive maintenance program was implemented at one of the sites surveyed, the actual leak reduction and cost savings agreed well with the results predicted from the estimated repair costs. The payback period for repairs plus the cost of the leak measurements was slightly less than 3 months. The net one year savings for this site, including the cost of leak measurements, was $62,900. If the repairs remain effective for two years, the net savings would be $143,900.

1. Introduction and Summary

This report describes a cooperative program sponsored by PRC International (PRCI), the Gas Research Institute (GRI), and the U.S. Environmental Protection Agency (EPA) Gas Star program to measure leak rates at natural gas facilities. The goals of this program were to refine component emission factors for these facilities, to determine the most effective ways to detect and quantify leaks, and to evaluate cost effective options for leak mitigation.

Leak rate measurements were initially made at thirteen compressor stations. Ten of these sites were selected for four quarters of surveys. The quarterly measurements were made to evaluate the leak rate trends over time and to examine the cost and effectiveness of leak mitigation strategies. This report presents the emission factors for natural gas compressor stations, the trends in leak rates over time, and a cost benefit analysis of leak mitigation. The results of this work are summarized below:

1) A total of 34,400 components were surveyed at the thirteen facilities. These sites ranged in size from smaller stations with only 2 centrifugal compressors to larger stations with up to 15 reciprocating compressors. The total leak rate from initial measurements conducted at the 13 sites was 536,100 Mcf/yr; at $2/Mcf this is equivalent to $1,072,20O/yr.

2) The largest total leak rate from an individual site was 200,000 Mcf /yr ($400,000 at $2/Mcf), which accounted for 37% of the total leak rate from all sites. The largest source at this site was venting from the power gas system used to control compressor unloaders (142,000 Mcf/yr). This was not a significant source at other sites.

3) The top 10% of leaking components from all sites account for 91% of the total leakage. Leakage from standard components (such as valves, flanges, and threaded fittings) accounted for 20% of the total leak rate, leakage from the rod packings on reciprocating compressors accounted for 38%, and leakage from other vented components accounted for 42% of the total leakage. If the power gas vent leakage, described in item 2 is not included, then standard components account for 27% of the leakage, rod packings for 52%, and vent systems for 21%.

4) Many past leak survey programs for the gas industry have been implemented using EPA Method 21 on a quarterly basis, with a repair threshold of 10,000 parts per million (ppm). This is not cost effective because the uncertainty in determining leak rates by this method can be over a factor of 1000. Leak detection can be accomplished faster and more economically using soap solution and catalytic oxidation/thermal conductivity detectors. Ultrasonic detection may also be useful as a rapid screening method but may miss significant leaks due to noisy backgrounds at the site or due to the large variation of noise levels that different types of leaks may generate.

5) A reciprocating compressor facility with seven to eight compressors could be expected, on average, to develop new leakage at standard components of 2,700 Mcf/yr. Approximately 75% of the total new leak volume occurs at compressor components even though they only comprise approximately 30% of the total components at a site. Follow-up survey costs can be reduced by focusing on the compressor areas.

6) A centrifugal compressor facility with two compressors could be expected to develop new leakage at standard components of approximately 100 Mcf/yr. The results are indicative of the fact that these facilities do not experience the type of vibrational stresses typically encountered at reciprocating compressor stations.

7) Measurements of leakage across compressor rod packings made during this and other work indicate that 25% to 33% of rod packings maintain leak rates below 100 Mcf/yr. This data set included bronze and bronze/Teflon packings with an average age of two years, and also included packings on both idle and running compressors. Consequently it seems possible to maintain leakage at less than 100 Mcf/yr. However, to do so may require more rigorous maintenance than is currently applied at many sites. In addition to changing the rod packing, it may be essential to check the surface roughness of the compressor rod and monitor the condition of the packing cup surfaces and rework these as necessary. Rod packings at sites in this study that paid more attention to these issues had less than one third the average leak rate of sites that focused only on changing packing. Additionally, over 80% of the rod packings that could maintain leak rates below 100 Mcf/yr were found at the sites which paid greater attention to packing maintenance.

8) The cost of repairing leaks was compiled using actual and estimated costs supplied by maintenance personnel at the compressor stations. If leaks with an estimated payback period of one year or less were repaired

(assuming $2/Mcf as the value of gas), the average payback period for the entire maintenance program would have been approximately 4 months and the total leak reduction at the sites would have been 71%. The average net savings per site for the first year would have been $39,500, and for the second year would have been $98,400. If the cost of the leak measurement program were included, the payback period would have been slightly less than 7 months with an average net first year savings of $26,800, and an average net second year savings of $85,600.

9) When a comprehensive maintenance program was implemented at one of the sites surveyed, the actual leak reduction and cost savings agreed well with the results predicted from the estimated repair costs. The payback period for repairs plus the cost of the leak measurements was slightly less than 3 months. The net one year savings for this site, including the cost of leak measurements, was $62,900. If the repairs remain effective for two years, the net savings will be $143,900.

2.0 Site Descriptions

Natural gas transmission compressor stations are used to boost pressure at various intervals along transmission pipeline to overcome the pressure losses over the long distances of pipe. Most sites use either gas-tired reciprocating engines or turbines to drive compressors; some electric driven centrifugal compressors have been installed but are not common in the industry at this time. At transmission stations, typical suction pressures on the inlet side of the compressors ranges from 500 psig to 700 psig while the discharge pressures at the outlet side of the compressors ranges from 700 psig to 1000 psig. Pressures at storage sites may be much higher. The compressors at most transmission stations are installed in a parallel configuration so that compressors can be taken on and off line to increase or decrease the throughput of the station as needed. Each compressor can be isolated from the station throughput and de-pressurized if necessary for maintenance. The entire station can also be isolated from the main pipeline flow and de-pressurized for either annual maintenance or in the case of an emergency.

Table 1 presents the characteristics of the facilities surveyed. The thirteen facilities were located in a wide range of geographical areas in the U.S. and Canada and also varied in size, age and types of compressors. A total of 34,400 components (flanges, connectors, valves, open ended lines, etc.) were surveyed at these sites.

Table 1. Description of Sites Surveyed

Site	Region	Year Built	Description	Initial Survey Date
Site 1	South Central - US	1950	13 Reciprocating Compressors	8/96
Site 2	South East - US	1967	15 Reciprocating Compressors	5/97
Site 3	South Central - US	1962	4 Reciprocating Compressors	4/97
Site 4	South West - US	1967	7 Reciprocating Compressors	9/96
Site 5	North Central - US	1960	6 Reciprocating Compressors	10/96
Site 6	South Central - US	1960	8 Reciprocating Compressors	1/97
Site 7	Western Canada	1972	5 Reciprocating Compressors, 2 Turbines	4/96
Site 8	Mid West - US	1960	3 Reciprocating Compressors	9/95
Site 9	Mid West - US	1960	2 Reciprocating Compressors, 3 Turbines	9/95
Site 10	South Central - US	1968	8 Reciprocating Compressors	7/97
Site 11	Western Canada	1990	2 Turbines	4/96
Site 12	Mid West - US	1990	2 Turbines	9/95
Site 13	Mid West - US	1990	2 Turbines	9/95

3.0 Field Measurement Methods

Comparisons of leak detection and quantification techniques were made during the initial stages of this work to determine the most cost effective methods for determining leak rates at natural gas compressor stations. Details of this comparison are presented in Appendix I. The use of flame ionization detectors, catalytic oxidation/thermal conductivity detectors, leak detection bubble solution, and ultrasonic detection were tested during this work. The amount of time to perform each method, the number of leaks found, and the total leak rate were determined for each technique.

When used by experienced personnel, the combination of homemade soap solution and a catalytic oxidation/thermal conductivity (CO/TC) detector was as effective as the more sensitive flame ionization detectors (FID) in terms of the total number of leaks found. Technicians using soap solution and the catalytic oxidation/thermal conductivity detector could screen 40% more components in the same amount of time as those using the FID. Additionally, the initial investment in the soap and CO/TC method is approximately 10% to 20% of the cost of an FID.

A variety of commercial and homemade leak detection solutions were also tested in the laboratory to determine their effectiveness. Although the performance of these solutions did vary, most of the solutions were found to be satisfactory and the performance was not related to price. The best performing commercial solution was a factor of 10 less expensive than the most expensive solution. Homemade solutions from children's bubble soap or shampoo were also found to be effective and could be made for approximately 10% of the cost of even the cheapest commercial solutions.

Although ultrasonic leak detection was able to find leaks at compressor stations, it was not effective at all locations. The volume and frequency of ultrasonic noise that leaks generate varies considerably even for leaks of approximately the same leak rate. Additionally, background or internal noise may prevent the ultrasonic leak detection in some areas of a facility. Consequently, ultrasonic leak detection is probably best used as a secondary screening tool for quality assurance during comprehensive leak detection programs or as a rapid leak screening technique, if comprehensive screening is not required.

Although emission factors and correlation equations could estimate average leak rates within 45% to 89% they were not effective at estimating leak rates for individual components. It is essential to accurately determine the leak rates for individual components to achieve cost effective leak reduction. When leak rates were estimated from screening concentrations using correlation equations, the wrong components were targeted for repair. Actual leak rates varied from those predicted by the correlation equation by factors exceeding 1000. The largest 20% of the leaks as determined by correlation equation actually only accounted for 40% of the total leak rate at one site while repairing the leak rates from the actual largest 20% leaks would result in a reduction of 82%.

Based on these results, leak detection was performed using soap solution and catalytic oxidation/thermal conductivity (CO/TC) detector. Any leaks found were tagged and measured. Leaks below 8 - 10 scfm were measured using the Hi-Flow sampler (Howard et al., 1995a), while larger leaks (almost exclusively at vents) were measured using rotameters, hot wire anemometers, or bag expansion techniques. Details on these measurement methods are included in Appendix II.

4.0 Results

4.1 Leak Rates and Emission Factors

Table 2 provides a summary of the results from the first quarter leak surveys. The total leak rate includes leakage from standard components such as valves, flanges, and connectors, compressor rod packing seals, and the blowdown system (unit valves on depressurized compressors, blow down valves on pressurized compressors, and station blowdown valves). The average total leak rate per facility was 41,000 Mcf/yr, or $82,00O/year at $2Mcf. The average leak frequency (number of components leaking per number of components surveyed) was 5%.

Table 2. Summary of Site Survey Data

Site	Number of Components	Total Number of Leaks	Leak Frequency	Number of Reciprocating Compressors	Number of Centrifugal Compressors	Total Leak Rate (Mcf/Yr)
Site 1	2880	160	4.4%	13	0	23,000
Site 2	3642	206	5.3%	15	0	24,500
Site 3	1184	49	4.1%	4	0	3,650
Site 4	4272	193	4.5%	7	0	200,000
Site 5	3654	205	5.6%	6	0	22,700
Site 6	3473	180	5.2%	8	0	48,400
Site 7	3817	243	6.4%	5	2	56,500
Site 8	2564	117	4.6%	3	0	75,000
Site 9	2472	165	6.7%	2	3	16,400
Site 10	2082	70	3.3%	8	0	55,600
Site 11	2424	144	5.9%	0	2	2,970
Site 12	1362	46	3.4%	0	2	385
Site 13	1362	69	5.1%	0	2	7,000
Average ± Standard Deviation	**2707 ± 1022**	**142 ± 66**	**5% ± 1%**	**7.1 ± 4.2**[1]	**2.2 ± 0.4**[2]	**41,200 ± 51,200**

[1] Average for sites with only reciprocating compressors.

[2] Average for sites with only centrifugal compressors.

Table 3 presents emission factors with associated 95% confidence intervals for components under main line pressure conditions, typically 500 to 1000 psi. These emission factors are divided by location either on or off of a compressor, since components located on a compressor undergo more thermal and vibrational stress than those not on compressors.

As in past work sponsored by GRI (Howard et al, 1995b) unit valve leakage on de-pressurized compressors constituted the largest component emission factor at compressor transmission stations. The sample size for this component group is small because most of the stations surveyed tended to leave their compressors pressurized when taken off line. Component emission factors for the starter gas vent, dry seal, and wet seal categories are also based on small sample sizes and may not be representative.

Table 3. Component Emission Factors with Associated 95% Confidence Levels - Main Line Pressure.

	MAIN LINE PRESSURE			
	ON COMPRESSOR		OFF COMPRESSOR	
Component Description	**Sample Size**	**Emission Factors** (Mcf/Yr/Source)	**Sample Size**	**Emission Factors** (Mcf/Yr/Source)
Ball/Plug Valve	189	0.64 ± 1.04	2406	5.33 ± 3.71
Blowdown Valve	—	—	57	207.5 ± 171.4
Compressor Cylinder Joint	148	9.9 ± 11.1	—	—
Packing Seal - Running	178	865 ± 247	—	—
Packing Seal - Idle	42	1266 ± 552	—	—
Compressor Valve	2324	4.1 ± 3.8	—	—
Control Valve	—	—	33	4.26 ± 7.13
Flange	864	0.81 ± 0.89	2727	0.32 ± 0.21
Gate Valve	—	—	1476	0.61 ± 0.43
Loader Valve	940	17.2 ± 5.6	—	—
OEL	—	—	168	81.8 ± 79.6
PRV	—	—	117	57.5 ± 63.2
Regulator	—	—	171	0.2 ± 0.21
Starter Gas Vent	—	—	5	40.8 ± 43.3
Threaded Connectors	1625	0.74 ± 0.46	10338	0.60 ± 0.30
Centrifugal Seal - Dry	—	—	14	62.7 ± 66.3
Centrifugal Seal - Wet	—	—	2	278
Unit Valve	—	—	12	3566

Table 4 presents component emission factors under fuel gas pressure, typically 70 to 100 psi on reciprocating engines. Fuel gas components on the compressor are largely at the top of the pistons in the area of greatest vibration and heat, which may be the reason some fuel gas components have larger emission factors than mainline components even though the pressure is an order of magnitude lower. The fuel gas components only leak while the compressor is running because the fuel system is usually blowndown when the compressor is idle, even if the compressor is left pressurized.

Table 4. Component Emission Factors with Associated 95% Confidence Levels - Fuel Gas Pressure.

	FUEL GAS PRESSURE			
	ON COMPRESSOR		OFF COMPRESSOR	
Component Description	**Sample Size**	**Emission Factors** (Mcf/Yr/Source)	**Sample Size**	**Emission Factors** (Mcf/Yr/Source)
Ball/Plug Valve	414	0.1 ± 0.1	654	0.51 ± 0.37
Control Valve	—	—	69	2.46 ± 3.89
Flange	—	—	1650	0.20 ± 0.19
Fuel Valve	479	27.6 ± 13.5	—	—
Gate Valve	—	—	640	0.43 ± 0.36
OEL	—	—	42	2.53 ± 2.19
Pneumatic Vent	—	—	14	76.6 ± 118.1
Regulator	—	—	103	4.03 ± 3.98
Threaded Connectors	2511	1.21 ± 1.66	3654	0.32 ± 0.16

Figure 1 and 2 illustrate typical leak rate distributions for two facilities surveyed. The leak rate distributions contain all leaking components (i.e., compressor packing seals, blowdown valves, plug/ball valves, gate valves, flanges, connectors, etc.). At Site 6, shown in Figure 1, the top 10% of leaks account for 60% of the total site emissions. These 18 leaks comprise 11 compressor rod packings, 4 fuel valves, 1 unloader valve, 1 station blowdown, and 1 connector. The total savings in gas would be approximately 29,40OMcf/yr, or \$48,800/yr at \$2/Mcf.

At Site 1, shown in Figure 2, the top 10% of leaks account for 85% of the total site emissions. These emissions are composed of 16 leaks which include (not in order of magnitude) 6 compressor packing seals, 3 blowdown valves, 2 unit valves, 2 plug valves, 1 flange, 1 unloader valve, and 1 connector. The gas savings in this case would be approximately 24,500 Mcf/yr or \$49,00O/yr at \$2/Mcf.

Based on the field measurements conducted during this program, it appears that the key to economic and effective leak reduction is to target the relatively small number of large leaks that contribute most to a facility's fugitive emissions. Most leak detection and repair programs depend only on screening concentrations to determine which leaks to repair. Due to factors such as wind speed and sample probe placement, screening concentrations for a given leak can vary over three orders of magnitude, such that the leak could be 1000 times larger or smaller than the estimated value. Screening concentrations also cannot differentiate the size of the largest leaks at a facility (which contribute most to the facilities emissions) because they result in concentrations that are off scale of the screening instruments. Furthermore, since the correlation equations are designed for maximum screening concentrations of 10,000 or 1OO,OOOppm, any leak above these values has the same estimated leak rate (known as a "pegged source" emission factor). However, especially in the natural gas industry, a large percentage of leaks screen above these concentrations that are not cost effective to repair. Consequently, screening concentrations do not provide the information required to make cost effective decisions on leak repair. Only by knowing the actual leak rate can the cost of the leak repair be compared to the cost of the lost gas.

The distribution of total leak rates at the facilities surveyed in this program is shown in Figure 3. Based on the thirteen sites surveyed, the top four sites (30% of the total sites) account for nearly 70% of the total emissions. Sites within the same system can have large differences in leak rates. Consequently, it can be misleading to extrapolate leak rates for an individual system based on the survey of a single station.

Figure 1.
Site 6 - Leak Rate Distribution

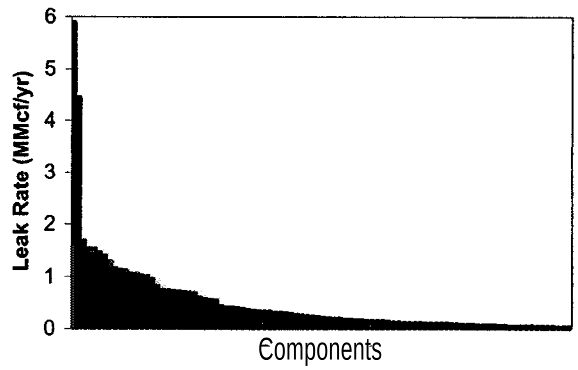


Figure 2.
Site 1 - Leak Rate Distribution

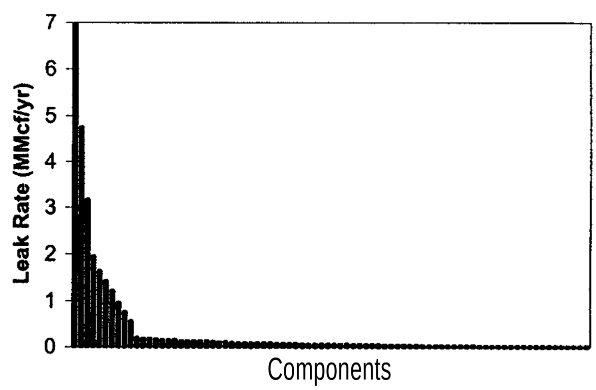
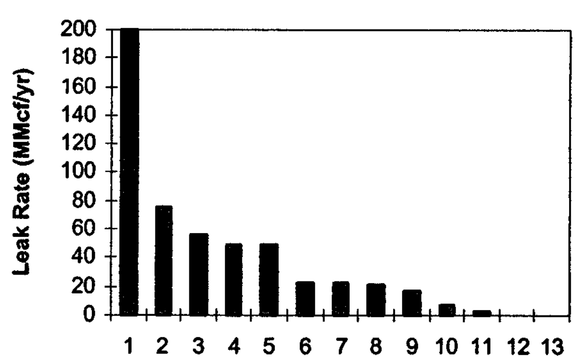


Figure 3.
Leak Rate Distribution -All Sites



4.2 Leak Rate Trends

The trend in leak rates over time is affected by changes in existing leaks and the development of new leaks. To look at the changes in existing leaks, emission factors were calculated for the leaks found at standard components during the first quarter of the survey using only the leaks that were reportedly not repaired at any time during the study period. The emission factors were then recalculated using the leak rates measured for these same leaks at the end of the fourth quarter. Leaks found in the following quarters were not included in this analysis. Because these emission factors do not include leaks that were repaired during the project and only include the ten sites at which quarterly measurements were made, they do not agree with the emission factors listed in Tables 3 and 4 and should only be used for comparison of leak rates over time.

Table 5. 1st and 4th Quarter Emission Factors Based on Leaks Found in the 1st Quarter (Non-Repaired Components Only)

Components	Located On Compressor (Mcf/yr/component)		Located Off Compressor (Mcf/yr/component)	
	1st Quarter[1]	4th Quarter[2]	1st Quarter[1]	4th Quarter[2]
Ball/Plug Valve	0.47	1.20	0.78	0.38
Threaded Connectors	0.76	0.91	0.32	0.25
Flange	0.14	0.38	0.19	0.21
Gate Valve	0.24	0.14	0.61	0.37
Open Ended Line	7.09	4.30	15.35	28.82
Compressor Valve Cap	3.03	6.59	N/A	N/A
Unloader Flange	4.38	2.95	N/A	N/A
Unloader Valve	6.19	3.47	N/A	N/A
Compressor Cylinder Joint	16.22	25.06	N/A	N/A
Fuel Valve	3.47	3.39	N/A	N/A

[1]Component leakage that was detected during the 1st quarter.
[2]Component leaks that were detected during the 1st quarter, but measured in the 4th quarter.

The ball/plug valve, gate valve, and open ended line categories showed considerable variability over time for components located both on and off the compressor. This may be due in part to variations of valve positions between measurements. Some valves (including ball, plug, gate, fuel and compressor unloader valves) will leak more in one position than another. Leak rates from valves may also vary if the valve is operated and then returned to its original position. Additionally, undocumented repairs may have been made in some cases.

Leakage from flanges and threaded fittings located off the compressor did not show large changes. These components do not have moving parts and are not subject to the same stresses typically associated with components on compressors. The open ended line category showed nearly a factor of two increase, indicating a need to monitor these type of components more frequently than others.

For components located on the compressor, several component categories showed a decrease in leak rate over time. However, most of these categories (gate valve, open ended line, unloader valve, and fuel valve) are components whose leak rate may vary due to the component position as discussed previously. The leak rate for compressor cylinder joints and compressor valve caps increased by approximately a factor of two between the first and fourth quarters. These increases indicate that these components should be monitored more routinely than others and that early maintenance may be more important once these leaks are discovered.

Table 6 summarizes the development of new leaks at standard components located on and off reciprocating compressors.

Table 6. Development of New Leakage At Components Located On and Off Reciprocating Compressors

4th Quarter Leak Rate at New Leaks (Mcf/yr)[1]			Number of New Leaks[1] Developed by 4th Quarter		
Total[2]	Found On Compressors	Fraction on Compressors	Total[2]	Found On Compressors	Fraction on Compressors
18,660	13,820	74%	433	233	54%

[1]New leaks are defined as any leak found after the first quarter survey.
[2]Based on emissions from facilities with reciprocating compressor engines only.

At the sites with reciprocating compressors, a total number of 433 new leaks (1.4% of the components surveyed) had developed by the end of the 4th quarter with a total leak rate of 18,660 Mcf/yr. This equates to 3.6% of the total leak rate found during the 1st quarter at these sites and an average of 263 Mcf/yr per compressor. New leakage developed fastest at components located on compressors, where 54% of the total new leaks and 74% of the total new leak rate occurred. As discussed previously, this is probably due to the higher vibration and heat stress on compressor components. Components located on compressors make up only 30% of the total number of components surveyed at a typical facility. Consequently, once an entire facility has been surveyed, follow up surveys can focus on the compressor components and vent systems to reduce the time and effort of the program. Additionally, since the vent systems and components located on compressors account for 93% of the total leak rate found at these sites, it would also be feasible to focus the initial survey on these areas to reduce the survey costs.

Based on the total new leakage observed in the 4th quarter from reciprocating compressor facilities (18,660 Mcf/yr), the estimated increase in leakage per facility would be approximately 2,670 Mcf/yr, or $5,34O/yr at $2/Mcf, with approximately 75% of this leakage coming from compressor components. The average reciprocating compressor station in this study would have 3100 components and 7 reciprocating compressors per site.

The average increase in new leakage at the sites with only centrifugal compressors was approximately 100 Mcf/yr for an average of 5OMcf/yr/compressor. The average facility consisted of 1700 components and 2 centrifugal compressors. The increase in new leakage volume from the 2nd to 4th quarters was approximately 5%. The increase in new leakage is smaller at sites with centrifugal compressors than at sites with reciprocating compressors, probably due to the fewer number of total components, the fewer number of components located on the compressors (approximately 10% of the total components at the site), and the lower vibrational stress experienced by these components.

4.3 Compressor Rod Packing Leak Rates

Leak rates across rod packings accounted for approximately 38% of the leakage observed at compressor stations. At individual sites, the fraction of leakage ranged from 17% to 70%. Consequently, rod packings deserve considerable attention when evaluating cost effective strategies for mitigating leakage.

Appendix II (Leak Rates from Compressor Rod Packings at Natural Gas Transmission Stations) presents the details of the leak measurements made at compressor rod packings during this project. The key results from this work are:

1) The total compressor packing seal leakage measured during the 1st quarter surveys was 203,700 Mcf/yr, equivalent to $407,400/yr at $2/Mcf. This equates to approximately 38% of the total leakage from compressor facilities surveyed during this study.
2) The average leak rate for rod packings on running compressors was 870 $\pm$ 250 Mcf/yr; the average leak rate for rod packings on idle but pressurized compressors was 1270 $\pm$ 550 Mcf/yr.
3) Leaving idle compressors at fuel gas pressure (100 to 120 psi) instead of full pressure (500 to 700 psi) did reduce idle/pressurized packing seal leakage. Reductions in average rod packing leakage ranged from 600 to 1200 Mcf/yr/seal equivalent to a reduction by a factor of two to three. However, average leak rates still exceeded 400 Mcf/yr ($8OO/yr) while well maintained rod packings can generally reduce leakage to less than

100 Mcf/yr on fully pressurized systems. It should be noted that the reduced pressure results are based on a limited number of measurements from only two facilities.

4) Approximately 25% of the rod packings surveyed had leak rates less than 100 Mcf/yr. These measurements were made on a mixture of idle and running compressors and contained both bronze and bronze/Teflon packings. In a separate study sponsored by a private client, approximately 33% of the rod packings had leak rates less than 100 Mcf/yr. The average age of the packings in this private data set was two years, and also contained a mixture of packing materials under both idle and running modes.
5) Results from this study as well as measurements conducted for a private client, indicate that if a thorough maintenance approach is applied to rod packing replacement, then leakage of less than 100 Mcf/yr is an achievable goal.

Because of the enormous variability in both rod packing leak rates and the maintenance practices at sites, a rod packing distributor (T.F. Hudgins, distributor of C. Lee Cook rod packing) was interviewed to determine if a set of recommended maintenance practices existed that could reduce rod packing leakage (Parr, 1998). The following points summarize the recommendations of this distributor:

1) Compressor Rods:

a) Compressor rod misalignment (or rod run-out) should not exceed 0.004”.
b) Rod taper caused by uneven wear may also cause leakage, but there is no set guideline for the point at which this becomes a problem.
c) Oversized rods will cause the arc of the packing to be off center and leakage will result.
d) Rod finish should be between 8 to 12 pin µms Smoother finishes (<8 µin) ill not allow the packing material to imbed into the rod, while rougher finishes will cause excessive wear and tear on the packings. A new rod should be able to last for at least 15 years in a transmission pipeline application and can be expected to cost approximately $3000 to $3500.

2) Packing Cups and Case:

a) The packing cup surfaces must be flat and smooth for the packing rings to seal to the face of the packing cup. Packing cups may require lapping to maintain this surface over time. One suggested test to determine if the packing cups require lapping is to hold a straightedge to the cup surface, shine a light from the opposite side, and look for light underneath the straightedge. It may be useful to stock a spare packing case at the site, at a cost of approximately $700.
b) The packing case must allow the cups to float vertically and horizontally so that the packing can move up and down and side to side within the tolerances of rod misalignment.

3) Packing Materials

a) The most common packing material is carbon filled Teflon used in combination with a bronze support backing ring. For higher temperature applications, bronze filled Teflon products conduct heat away better. For applications where hydrogen sulfide is present, cast iron is a better choice than bronze for the backing ring.
b) Teflon packings in service at pressures greater than 200 psi should have a backing ring. Excessive heat can cause Teflon to extrude; excessive dirt will cause wear on the packing.
c) Teflon packings can be lubricated or non-lubricated as the site chooses. In early carbon filled Teflon packing products, the carbon was leached out by lubrication, so that once lubrication was started it needed to be maintained. However, this is no longer true.
d) Intermittent lubrication can cause materials that wear off the packing to accumulate and should be avoided.
e) If hydrocarbon liquids are coming through in the gas stream, they may break down the lubricating oil and cause metal on metal wear if bronze packings are used, even though it may appear that adequate lubrication is present. If this scenario is likely, a Teflon packing may be a better choice to prevent this wear. Teflon packings may also reduce rod wear and will conform better to an uneven rod diameter.

4) The most common cause of leakage into the distance piece is the gasket on the crank end of the packing gland. This is usually a copper gasket, although some applications now use a Flexitallic™ gasket. If the gasket is over-tightened, it may deform and leak. Conversely, it may also leak if not tightened enough or if misaligned.

Many sites change rod packings without checking the packing case or the rod to determine if maintenance is needed. Based on the above information from T.F. Hudgins, the rod packing leak data were resorted into two groups: 1) sites that only changed rod packing without pulling the compressor rod, and 2) sites that changed rod packing by removing the rod and also inspecting the packing case. Of the ten reciprocating compressor sites surveyed, half changed the packing with the rod in place and half changed the packing by pulling the rod. This was not always a specific policy and all sites were familiar with both methods, but the sites were sorted by the predominant method used.

A summary of the rod packing leakage by replacement method is shown in Table 7. For running compressors, sites which changed rod packings with the rod in place had over twice the average leakage per rod packing as did the sites which conducted the more lengthy maintenance procedure of pulling the rod to change the packing. For idle compressors, the sites which changed rod packings without removing the rod had almost four times the average leak rate of sites where rods were removed, although the sample size for these sites is smaller and the results more uncertain.

Table 7. Rod Packing Leak Characteristics by Replacement Method

	Change Packing with Rod in Place	Change Packing with Rod Removed
Emission Factor Running Compressor	1,320 ± 530 Mcf/yr (Sample Size = 76)	515 ± 140 Mcf/yr (Sample Size = 98)
Emission Factor Idle Compressor	1,890 ± 2,390 Mcf/yr (Sample Size = 22)	490 ± 275 Mcf/yr (Sample Size = 24)
Percentage of Total Leaks <100 Mcf/yr	17%	83%
Percentage of Total Leaks > 1000 Mcf/yr	70%	30%

As discussed previously, because approximately 25% of the rod packings surveyed during this project had a leak rate of less than 100 Mcf/yr, this rate of leakage appears to be an achievable goal. As shown in Table 7, of the rod packings surveyed during this project with leak rates of less than 100 Mcf/yr, 83% of these were at sites which pulled the rod to change packing, and only 17% were at sites that changed the packing with the rod in place. Conversely, larger leaks were more likely to be present on rod packings at the sites which change rod packings with the rod in place. 70% of the leaks larger than 1000 Mcf/yr occurred at these sites, while only 30% of the leaks greater than 1000 Mcf/yr occurred at sites which changed packing by removing the compressor rod.

Table 8 details measurements conducted for a private client, in which compressor rod packing leak rates were measured before and after rod packing maintenance. The compressor packing seal and rod replacement was conducted by site personnel using materials provided by T.F. Hudgins. This replacement was performed according to the recommendations by T.F. Hudgins described above.

Table 8. Comparison of Packing Seal Leak Rates Before and After Thorough Maintenance

	Before Repair		After Repair	
Compressor	Total Leak Rate ($/yr)[1]	Leak Rate/Seal ($/yr)[1]	Total Leak Rate ($/yr)[1]	Leak Rate/Seal ($/yr)[1]
Compressor 301 - Running (4 Packing Seals)	16,600	4,150	912	228
Compressor 302 - Running (4 Packing Seals)	8,160	2,040	863	218

[1]Cost of gas = $2/Mcf

As Table 8 illustrates, a thorough approach to packing maintenance significantly reduced the rod packing leakage. The leakage was reduced to an average of 112 Mcf/yr ($223/yr), very close to the 100 Mcf/yr level that was predicted to be achievable from the data in this study. Consequently, it appears that the recommendations by T.F. Hudgins may be a key tool in minimizing rod packing leakage.

In order to determine the point at which maintenance is required, rod packing leakage should be monitored on a routine basis. This monitoring should include both packing cup vent and distance piece leakage, since approximately one third of the observed leakage was through the distance piece. In measurements made for private clients, leakage into the distance piece has in some instances ranged from 5000 Mcf/yr to 50,000 Mcf/yr without showing significant packing cup vent leakage. These higher values represent not only significant losses of gas (up to $ 100,OOO/yr for a single leak) but may also present a safety hazard by causing a build up of gas pressure in the distance piece which might result in gas entering the crankcase. We do not know what leak rates constitute a risk for this scenario. However, leak rates into the distance piece have exceeded 10,000 Mcf/yr (20 scfm) at 10% of the facilities we have surveyed as part of this program and other programs for private clients. At 4% of these facilities leak rates into the distance piece have exceeded 45,000 Mcf/yr.

New approaches to reduce compressor packing seal leakage are currently being developed. A&A Environmental Seals (Houston, Texas) has developed a system that captures gas leaking from rod packings for use as fuel gas. Tests of this system at natural gas transmission compressor stations care currently anticipated to begin in the winter of 1999 as part of the EPA Environmental Technology Verification Program for greenhouse gas technology. Potential benefits of this type of system would be the reduction of gas loss from rod packings to essentially zero and the reduction of rod packing maintenance costs, since theoretically rod packings would only be replaced during major overhauls. As described above, it appears that current technology can reduce rod packing leak rates to 100 Mcf/yr when correctly applied. Consequently, the cost and complexity of any new technology in rod packing systems must be minimized for these new systems to be cost effective and attractive.

4.4 Leak Mitigation Costs and Paybacks

Interviews with facility maintenance personnel and data from leak repair sheets were used to determine average leak repair costs. These costs are presented in Table 9. The costs were calculated using the hourly rate quoted for maintenance personnel with an additional 50% increment to cover costs such as fringe benefits. The costs of materials were included as quoted with no markup.

Table 9. Average Leak Repair Costs

Component	Type of Repair	Average Cost ($)
Ball Valves – 1"	Replace	120
Bull Plug on Valve	Add Teflon Tape and Tighten	15
Compressor Blow Down	Replace	600
Compressor Blow Down	Rebuild	200
Compressor Valve Cap	Replace Gasket	60
Flange – 30"	Change Gasket	1,250
Flange – 6"	Change Gasket	300
Fuel Valve	Replace	200
Gate Valve	Teflon Repack	40
Grease Port	Replace	80
Head End of Compressor	Pull and Change Gaskets	450
Loader Valve Flange	Replace Gasket	80
Loader Valve Stem	Rebuild	300
Needle Valve	Replace	100
Open Ended Line on Valve	Grease	45
Pig Receiver Door	Tighten	120
Pipe Thread Fitting	Tighten, Add Teflon Tape as Necessary	30
Plug Valves	Grease	40
Pressure Relief Valve – 1"	Replace	1,000
PRV Flange	Tighten	40
Rod Packing	Change Packing Rings Without Removing Rods	750
Rod Packing	Pull Packing Case and Rods to Change Rings, and Rework Packing Case	2,600
Rod Packing	Pull Packing Case and Rods to Change Rings, Rework Packing Case and Replace Rod	5,600
Station Blow Down	Reverse Plug	720
Tubing	Tighten	10
Union	Tighten	10
Unit Valve	Clean and Inject Sealant	70
Unit Valve – 10" Plug	Replace	2,960

Table 10 shows the theoretical results of applying these repair costs to the leaks found at the thirteen sites during the initial measurements. For this analysis, an payback period of one year was selected, so that any leaking components whose repairs could be paid for within one year were included. Repair costs assumed the most likely repair for successful leak reduction. For instance, the cost for rod packing repair includes the cost of completely reworking the packing case, replacing the rod packing, the labor involved in removing the rod from the compressor, and rod depreciation, assuming a packing replacement every two years and a rod life of 15 years. Less expensive repair costs were quoted at sites where packing rings were replaced with rods in place. However, as discussed in Section 4.3, it appears that effective rod packing maintenance requires the more thorough approach.

The following assumptions were used in this analysis:

1) If the rod packing leakage was greater than the cost of completely reworking the packing case, replacing the rod packing, and replacing the compressor rod, it was assumed that this maintenance would be necessary to mitigate the leakage. For lower leak rates, it was assumed that only the replacement of rod packings and the reworking of packing cases would be necessary to repair the leakage. After repair, it was assumed that the rod packing will leak less than or equal to $200/yr of gas whether idle or running, based on measurements taken during this and other work indicating that approximately 25% to 33% of rod packings with an average age of 2 years had a leak rate less than $2OO/yr (based on $2/Mcf).
2) Greased valves will still leak at 20% of the original leak rate.
3) Components are pressurized and leaking 365 days/year.
4) Except for rod packings, repairs are made under pressure or during a station outage so that gas is not lost due to blowing the system down.
5) The cost and savings of repairs at Site 4 for the power gas system vents are based on actual values from that site.

Table 10. Summary of Potential Gas Savings and Repair Costs

Site	Total Station Leak Rate ($/yr)[1]	Gas Saved By Repair ($/yr)[1]	Leak Reduction (%)	Repair Cost ($)	Payback Period (yr)	One Year Net Savings ($)	Two Year Net Savings ($)
Site 1	46,000	35,700	78%	18,800	0.53	16,900	52,600
Site 2	49,000	32,900	67%	16,000	0.50	16,900	49,800
Site 3	7,300	2,500	34%	315	0.13	2,200	4715
Site 4	400,000	212,000	53%	41,300	0.19	170,700	382,700
Site 5	45,400	40,700	90%	20,700	0.50	20,350	61,100
Site 6	96,800	70,800	73%	34,200	0.50	36,600	107,400
Site 7	113,000	99,200	88%	31,000	0.31	68,200	167,400
Site 8	150,000	132,000	88%	50,100	0.38	82,300	214,700
Site 9	32,700	23,800	73%	4,650	0.20	19,100	42,850
Site 10	111,300	102,600	92%	32,400	0.30	70,200	172,800
Site 11	5,930	1,240	21%	320	0.26	924	2,160
Site 12	770	490	63%	100	0.20	390	880
Site 13	14,000	10,800	77%	1,600	0.15	9,170	20,000
Total	**1,072,200**	**764,700**	**71%**	**251,500**	**0.33**	**513,900**	**1,279,100**
Average =	**82,500**	**58,800**	**71%**	**19,350**	**0.33**	**39,500**	**98,400**

[1]Cost of gas = $2/Mcf

Assuming that all components with a payback period of less than one year are repaired, the first year net savings would be $39,500 per facility, with a payback period of approximately four months. If repairs remain effective for two years, the net savings would average $98,400.

By the end of this study, the power gas vent leakage at Site 4 had been reduced by only 40%, which in turn lowered the average leak reduction observed for all sites to 71%. Although the leakage from the power gas vents accounted for a large percentage of the total leakage found during this study, we have found that it is not unusual to find leak rates from individual components to range as high as $1OO,OOO/yr. However, these leak rates can usually be reduced more successfully than the 40% reduction accomplished at Site 4.

Although only a few sites implemented repairs during this work, the repairs that were made proved cost effective. Table 11 presents the details of repairs conducted at Site 10, which performed the most repairs during this project.

Table 11. Summary of Repaired Leaks at Site 10

Leaking Component	Leak Rate ($/Yr)[1] Before Repair	After Repair	Savings ($/Yr)	Repair Cost[2] ($)	Pay-Back Period (Months)
Station Blow Down	$35,830	$210	$35,620	$720	0.2
Compressor Rod Packing	$19,260	$2,420	$16,840	$1,600	1.1
Compressor Blowdown	$15,010	$360	$14,650	$920	0.8
Compressor Rod Packing	$8,290	$1,200	$7,090	$1,200	2.0
Pig Receiver Door	$3,620	$0	$3,620	$120	0.4
PRV Flange	$790	$0	$790	$20	0.3
Fuel Valve	$340	$0	$340	$40	1.4
Fuel Valve	$340	$10	$330	$40	1.5
Fuel Valve	$330	$0	$330	$40	1.5
Compressor Valve Flange	$280	$1	$279	$20	0.9
Fuel Valve	$270	$20	$250	$40	1.9
Fuel Valve	$200	$0	$200	$40	2.4
Compressor Valve Flange	$190	$0	$190	$20	1.3
Union	$130	$6	$124	$10	1.0
Fuel Valve	$120	$0	$120	$40	4
Compressor Valve Flange	$120	$0	$120	$30	3.0
Compressor Valve Flange	$80	$0	$80	$30	4.5
Loader Valve Flange	$20	$0	$20	$30	18
Compressor Valve Flange	$20	$4	$16	$20	15
Bull Plug on Plug Valve	$10	$0	$10	$10	12
Compressor Valve Flange	$10	$3	$7	$30	54.1
Balancing Fuel Valve	$10	$3	$7	$5	8.6
Union	$10	$0	$10	$40	48
Union	$8	$0	$8	$10	15
Union	$7	$0	$7	$10	17.1
Union	$5	$0	$5	$10	24
Compressor Valve Flange	$5	$0	$5	$20	48
Total =	**$85,300**	**$4,240**	**$81,060**	**$5115**	**0.8**
Total Net One Year Savings = $75,950			**Total Net Two Year Savings = $157,000**		

[1] Cost of gas = $2/Mcf;
[2]Repair costs are those specified by Site 10 personnel, and may not agree with the average costs listed in Table 9

At Site 10, approximately $81,000 was saved by fixing 27 leaks at a cost of $5,115. The first year net savings would be $75,950, with a payback period of less than one month. Although the actual one year net savings ($75,950) compare reasonably well with the theoretical net savings detailed in Table 11 ($70,200), the actual leakage reduction accomplished at Site 10 was only 73%, as opposed to the theoretical 92% (Table 11). This result stems from the fact that the site did not choose a one year payback period guideline for repairs, but instead focused primarily on leaks, both large and small, that were convenient to fix. Consequently, some large compressor packing seal leaks, which would have contributed significantly to the facility gas savings and repair costs, were not fixed.

The results in Tables 10 and 11 do not include leak detection and measurement survey costs. If the sites listed in Table 10 were in the same region (for instance, if they had been stations along a single pipeline) and the survey was focused only on finding and measuring leaks but excluded component counts, emission factors, and maintenance cost data, the total cost for a one time survey of all of these sites would have been $90,000. Leak detection could be performed at a lower price by other contractors or by station personnel, but these type of surveys would not provide the necessary information to make cost effective maintenance decisions. Including the cost of the survey, the average payback period for the sites listed in Table 10 would be slightly more than five months, with a corresponding average one year net savings of $32,500 per site. The survey cost for Site 10 would have been approximately $9000 if it had been conducted as part of the entire program, resulting in a payback period of approximately two months. The net one year savings for Site 10, including the cost of leak measurements, would have been $67,000, while the net two year savings would be $148,000.

5.0 Conclusions

This report presents both the average gas losses and annual emissions factors for natural gas transmission stations. Results are based on leak measurements sponsored by PRC International, Gas Research Institute, and the US Environmental Protection Agency as part of the cooperative project to determine the most cost effective methods of mitigating leak rates at compressor stations. A total of 34,400 components were surveyed at thirteen sites throughout the US and Canada as part of this program.

Total leak rates at these facilities ranged from 385 Mcf/yr to 200,000 Mcf/yr, with an average leak rate of 41,200 Mcf/yr equivalent to $82,40O/yr at $2/Mcf. The leak frequencies at components ranged from 3.3% to 6.7%, with an average leak frequency of 5%. The lowest leak rates were observed at facilities with turbine driven centrifugal compressors.

Emission factors were calculated for components at both fuel gas and mainline pressures and located on and off the compressors. Components located on compressors leaked more and developed new leaks at a faster rate than components found elsewhere in the facility. This is probably caused by the larger vibrational and heat stresses experienced by components located on the compressor. The three largest emission factors were for unit valves on depressurized compressors, compressor rod packings, and blowdown valves on pressurized compressors. Compressor rod packing leakage was approximately 46% higher when the compressor is idle and pressurized as opposed to running.

Measurements of leakage across compressor rod packings made during this and other work indicate that 25% to 33% of rod packings maintain leak rates below 100 Mcf/yr. This data set included bronze and bronze/Teflon packings with an average age of two years, and also included packings on both idle and running compressors. Achieving this low rate of leakage requires more rigorous maintenance than is currently applied at many sites. In addition to changing the rod packing, it appears to be essential to check the surface roughness of the compressor rod and monitor the condition of the packing cup surfaces and rework these as necessary. Rod packings at sites in this study that paid more attention to these issues had less than one third the average leak rate of sites that focused only on changing packing. Additionally, over 80% of the rod packings that could maintain leak rates below 100 Mcf/yr were found at the sites which paid greater attention to packing maintenance.

The distribution of leak rates at components indicate that it is essential to identify the key leaks for repair. If leaks with an estimated payback period of one year or less were repaired (assuming $2/Mcf as the value of gas), leakage at facilities can be reduced by approximately 71%. Including the cost of survey, the first year net savings would be $32,500 per facility, with a payback period of slightly more that five months. If repairs remain effective for two years, the net two year savings would average $91,300 per site.

When a comprehensive maintenance program was implemented at one of the sites surveyed, the actual leak reduction and cost savings agreed well with the results predicted from the estimated repair costs. The payback period for repairs and the cost of the survey was approximately two months. The net one year savings for this site was $67,000, while the net two year savings if repairs remained effective would be $148,000.

6.0 References

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Appendix I

A Comparison of Leak Detection and Leak Quantification Methods at Transmission Compressor Facilities

Summary

Leak detection and quantification techniques were tested at natural gas transmission compressor stations to determine the time required to perform each method and the effectiveness of each method. The use of flame ionization detectors, catalytic oxidation/thermal conductivity detectors, leak detection bubble solution, and ultrasonic detection were tested during this work. The amount of time to perform each method, the number of leaks found, and the total leak rate were determined for each technique.

The use of a combination of homemade soap solution and a catalytic oxidation/thermal conductivity (CO/TC) detector when applied by experienced personnel was found to be as effective in the number of leaks found as using the more sensitive flame ionization detectors (FID). Moreover, the use of soap solution and the catalytic oxidation/thermal conductivity detector could screen 40% more components in the same amount of time as an FID. In addition, the initial investment in equipment for the soap and CO/TC method is approximately 10% to 20% of the cost of an FID.

A variety of commercial and homemade leak detection solutions were also tested in the laboratory to determine their effectiveness. Although the performance of these solutions did vary in terms of the size and durability of bubbles formed, most of the solutions were found to be satisfactory and the performance was not related to price. The best performing commercial solution was a factor of 10 less expensive than the most expensive solution. Homemade solutions from children's bubble soap or shampoo were also found to be effective and could be made for an average of a factor of 10 less than the cheapest commercial solutions.

Ultrasonic screening can detect leaks at transmission compressor facilities, but that the results are varied and susceptible to interference from background noise. At two of the test sites no leaks could be detected. However, under laboratory conditions the instrument was found to be very sensitive, and was able to identify a leak of 0.25 scfh at a distance of 12 feet. During further testing at three more sites, ultrasonic screening was used in conjunction with other screening instruments. Under this scenario, the ultrasonic instrument proved more successful, especially for larger leaks. Consequently, ultrasonic screening appears to be effective if used in conjunction with other leak detection methods. False positives due to internal noise can then be eliminated and areas with high levels of background ultrasonic noise that prevent the use of ultrasonic leak detection can be screened using other techniques.

Although emission factors and correlation equations could estimate average leak rates within 45% to 89% they were not effective at estimating leak rates for individual components. It is essential to accurately determine the leak rates for individual components to achieve cost effective leak reduction. When leak rates were estimated from screening concentrations using correlation equations, the wrong components were targeted for repair. At one of the sites surveyed, if all leaks that screened as a "pegged source" (> 10,000 ppm) were fixed, 112 leaks would need to be repaired, producing a corresponding leak rate reduction of only 62%. However, using actual leak rate data, if all components leaking greater than 30 Mcf/yr ($6O/yr at $2/Mcf) were repaired, only 22 leaks would require fixing. The corresponding total leak rate reduction would be 66%.

1. Introduction

Leakage of natural gas from natural gas processing, transmission, and distribution facilities may represent a significant loss of product for the natural gas industry. Additionally, natural gas is primarily methane, which is a potent greenhouse gas. The natural gas industry is seeking to reduce leakage of natural gas, thereby reducing both the cost of lost gas and the resulting fugitive emissions of methane to the atmosphere.

Fugitive emissions due to leaks from components such as valves, flanges, connectors, and open ended lines may contribute significantly to this gas loss and the resulting air emissions. To reduce leakage cost effectively, the most significant leaks at each facility must be identified and quantified. However, the methods of detecting and quantifying leak rates from these components are still evolving.

To determine the effectiveness of currently available methods, a comparison of several leak detection and quantification techniques used by the natural gas industry was sponsored by PRC International (PRCI), the Gas Research Institute (GRI), and the U.S. Environmental Protection Agency (EPA) Gas Star program. This comparison had three goals: 1) to determine the cost and time required for each method; 2) to gauge the effectiveness of the leak detection techniques by determining the number and size of leaks that could be found by any one method compared to the total leaks found by all methods; and 3) to compare the accuracy of leak rate estimation by different methods to actual leak rate measurements using the Hi-Flow™ Sampler.

2.0 Overview of Leak Detection and Quantification Techniques

2.1 Leak Detection Techniques

The four leak detection techniques used during this program were:

1) Application of soap solution to the surface of components, under gas pressure, and watching for the formation of bubbles;

2) Measurement of natural gas concentrations at or near the potential leak interface using an instrument with a flame ionization detector (US EPA Method 21);

3) Measurement of natural gas concentrations at or near the leak interface using an instrument with a combination of catalytic oxidation and thermal conductivity detectors; and

4) Detection of ultrasonic sound frequencies generated by the gas as it escapes from the component using an ultrasonic detection system.

The use of soap solution is the simplest and cheapest leak detection method and relies on the user to spray the solution on to the components and check for bubble formation, caused by leaking gas. Commercial leak detection solutions are available, but also viable is liquid soap, used for children's bubble toys or a shampoo, which can be mixed with water to form an economic and efficient bubble solution. Leaks detected by bubble formation generally fall into three categories: 1) small leaks that cause a slow formation of bubbles that may only be obvious 1 - 2 minutes after the solution has been applied, 2) intermediate to large leaks that cause immediate and obvious bubble formation and 3) very large leaks that visibly blow the soap solution away and do not bubble further. Effective use of soap solution requires leak detection personnel to watch the component as the soap solution is applied as well as to look back over an area of components that was soaped previously to see if any bubbles have formed on smaller leaks.

Soap solution screening is not applicable to all components. Flanges with deep crevices, open ended lines, very hot components, and components with liquid stream composition often cannot be soaped successfully. Soap solution may also require the addition of an antifreeze solution to prevent freezing at cold temperatures. Leak detection crews must also be careful not to spill soap solution where it could cause a slipping hazard.

Flame ionization detectors (FIDs) measure the variation of the electrical conductivity of a hydrogen flame as organic compounds are burned in the flame. These detectors can often measure hydrocarbon concentrations in air with detectable limits of less than 10 parts per million (ppm) of methane in air. This low detectable limit provides good sensitivity to leaks when the inlet probe of the instrument is held near the potential leak interfaces. However, drawbacks of flame ionization detectors include the need for hydrogen as a fuel gas, the need for frequent calibration, and poor operation at temperatures below 40°F.

Several companies, including Foxboro, Mine Safety Appliances, ThermoEnvironmental, Photovac, and Southern Cross produce FID instruments for leak detection and other applications requiring the measurement of hydrocarbons in air under field conditions. For this study, the Foxboro TVA- 1000 was used for the FID instrument. This instrument is an updated version of the OVA- 108 which has been used extensively at chemical and petroleum facilities to perform screening for fugitive emissions using EPA Method 21. Both versions are intrinsically safe. The OVA can measure concentrations from 1 ppm to 10,000 ppm (1%), while the TVA can measure concentrations from 1 ppm to greater than 50,000 ppm (5%). For concentrations above 20,000 ppm (2%), the TVA must use a multipoint calibration. The OVA has an operating temperature range of 50 to 104°F and requires a minimum ambient temperature for flame ignition of 59°F. Ideally the instrument is expected to provide 8 hours of continuous operation. Cold environments (<4O"F), use of the diluter probe (which restricts flow and causes the pump to work harder), and continued re-ignition of the hydrogen flame may reduce the instrument battery life to as low as 1-2 hours. The TVA has a wider operating temperature window (32 to 104°F). The battery life of the TVA is between 6-8 hours, although this is subject to change under the conditions described previously. The OVA weighs approximately 12 lb. and costs approximately $6800 while the TVA weighs approximately 13 lb. and costs approximately $9000.

Catalytic oxidation and thermal conductivity sensors have been combined in several commercial packages to provide measurement of natural gas concentration in air ranging from a low of 0.01% (100 ppm) to 100%. Manufacturers include Bascom-Turner Instruments, Mine Safety Appliances, and GMI. Catalytic oxidation detectors monitor the increase in temperature as oxygen reacts with hydrocarbons in the sample stream across a catalyst bed. These catalytic oxidation sensors generally measure gas concentrations in the range of 0.05% (500 ppm) to 4% (40,000 ppm) methane in air. Thermal conductivity sensors measure the change in heat loss from the sensor filament as the composition of the sample stream and its thermal conductivity changes. For this type of instrument, thermal conductivity sensors are typically used to measure gas concentrations in the range of 4% to 100%. These instrument systems automatically switch back and forth between the catalytic oxidation detector and the thermal conductivity detector as needed to cover the entire range of concentration from 0.05% to 100%.

The Bascom-Turner CGI-211 and the GM1 Gasurveyor 4 were used during this study to represent instruments using a combination of catalytic oxidation and thermal conductivity sensors. These sensors do not require hydrogen and are both intrinsically safe. The lower detectable limit of the CGI-211 is 300 ppm in the screening mode. It costs approximately $800 and weighs 1.25 lb. The lower detectable limit of the Gasurveyor 4 is 5 ppm and it weighs approximately 3.5 lb. Both the CGI-211 and Gasurveyor have an operating temperature range of -20°F to 14O"F, and provide approximately 8 hours of continuous operation under moderate conditions (~65°F). At lower temperatures, battery life is shorter. For instance, at temperatures less than 32^{0}F, the four batteries (size AA) for the CGI-211 need to be changed approximately every 3 hours.

Ultrasonic leak detection uses sound detectors tuned for the ultrasonic frequencies generated by gas as it escapes from a leak. Ultrasonic wavelengths tend to travel in straight lines, allowing leak detection to be conducted by pointing the probe at components and listening for an increase in sound intensity through head phones. During leak detection, the ultrasonic detectors are used to pinpoint areas based on the loudest sound. The ultrasonic probes typically provide frequency and sensitivity tuning capabilities so that in environments with large background noise levels, tuning can be used to focus the probe on a specific leak. Confirmation is attained by moving the scanner back and forth across the leak and listening for a change in sound level. Rubber focusing probes are also available to narrow the reception field and to block out ambient ultrasounds.

Two ultrasonic instruments, the UE Ultraprobe- and the Ultrasonic Translator Detector, were used during this study. The Ultraprobe costs approximately $4000. The Ultrasonic Translator Detector was an older unit supplied by one of the participating sites and the cost was unknown. Both units were certified intrinsically safe. No information was available concerning the battery life of the instruments.

2.2 Leak Quantification Techniques

Several methods are available to either estimate or measure leak rates at components. For this comparison, three quantification techniques were used: 1) EPA published emission factors based on average leak rates; 2) correlation equations which use screening concentrations to estimate emissions; and 3) actual leak rate measurements using the Hi-Flow^{TM} sampler.

Enclosure ("bagging") measurements have typically been considered the most accurate method for leak rate determination. The measurements are conducted by wrapping the leaking component with a non-permeable material and purging the enclosure with a measured flow rate of clean air or nitrogen. The leak rate is calculated by multiplying the purge flow rate and the concentration of natural gas in the outlet stream. Although enclosure measurements are generally accurate, they are too time consuming (typically one hour per leaking component) and thus expensive to conduct on all leaks at a facility.

In an attempt to combine the accuracy of enclosure measurements, but provide a faster and cheaper method for leak rate determination, correlations were developed to relate the concentration of a leaking component, as measured using an OVA, to the leak rate, based on enclosure measurements (CMA, 1989; API, 1996). Although these correlations make it easy to estimate leak rates, the inaccuracies are often as high as three orders of magnitude. Wind speed, the distance of the probe from the leak, and leak rate characteristics, such as exit velocity, affect how much of the leak actually is captured by the sample probe. Additionally, screening concentrations and correlation equations cannot accurately characterize leaks that are beyond the scale of the leak detectors ("pegged sources"). These pegged sources are assigned a separate emission factor which again may be high or low depending on the site. Since pegged sources contribute most to the total leak rates at a facility, the uncertainty in the emissions factors for pegged sources strongly effects the accuracy of the total facility estimate. During this study, total leak rates were estimated by multiplying the concentration, measured near the leaking component, by the screening correlation for that particular component type (API, 1996).

Another method developed to estimate total facility emissions is based on component emission factors. These factors were developed from leak rate data collected at various facilities, using the enclosure method. The emission factors define the average leak rate per component category, such as connectors, flanges, valves, etc. For a particular facility, by multiplying the number of components in each category, by their respective emission factor, total facility emissions can be estimated. The total leak rate estimates, for a given site, may be either high or low depending on the site specific maintenance and operational practices, as compared to the average of the sites from which data was collected to develop these factors. During this study, total leak rates were estimated by counting the number of components in each category and multiplying that number by the respective emission factor (API, 1996).

To overcome the uncertainties associated with emission factors and screening correlations, as well as the high cost of bagging studies, the Hi-Flow^{TM} Sampler was developed to make measurements with the same accuracy as enclosure measurements but at a speed approaching that of leak detection screening measurements (Howard et al., 1995). This sampler uses a high flow rate of air and a partial enclosure to completely capture the gas leaking from the component. During each leak measurement, the total sample flow rate and the concentration of gas in both the sample stream and background area near the leak are monitored. Emissions are calculated similarly to an enclosure measurement. The background concentration must be subtracted from the main sample flow concentration because it may be elevated due to other leaks in the vicinity of the leak being measured. Past comparisons of Hi-Flow sampler measurements to enclosure or direct meter measurements have agreed within ±15% (Howard et al., 1995).

3. Field Measurement Program

The field program was conducted at three natural gas transmission compressor stations. Sites 7 and 11 were located in Western Canada and Site 5 was located in the Midwestern United States. Measurements were conducted at Site 7 and Site 11 from April 9 - April 12, 1996 and at Site 5 from September 30 through October 4, 1996. To further assess the applicability of the Ultraprobe 2000, tests were also conducted at two private client facilities from August 10 through August 17,1998.

Site 7 had a total of five natural gas tired reciprocating compressors and two natural gas fired turbine driven centrifugal compressors. Components associated with two of the reciprocating compressors, one centrifugal compressor and the fuel gas metering system for the entire station were screened for leaks. This included components on the main body of each compressor, the fuel gas system for each compressor, and the suction and discharge valve area associated with each compressor. The leak detection methods used at this site were soap solution, the Foxboro TVA - 1000, the Bascom-Turner CGI-211, the GM1 Gasurveyor 4, and the UE Ultraprobe-2000. The total number of components screened for this comparison at Site 7 was 13 10.

Site 11 had two natural gas fired turbine driven centrifrugal compressors but no reciprocating compressors. The turbines were not running during the measurement program and as a consequence, the site had less background ultrasonic noise than Site 7. Soap solution and ultrasonic screening were performed in areas associated with the suction and discharge valves of each compressor, the station valve yard and inside one of the compressor buildings.

Site 5 had six natural gas fired reciprocating compressors but no turbine driven centrifugal compressors. Components at this site were screened by soap solution, the Foxboro TVA-1000, the Bascom-Turner CGI-211, and the Ultrasonic Translator Detector (C-4918A). As at Site 7, these components included those on the main body of each compressor, the fuel gas system for each compressor, and the suction and discharge valve area associated with each compressor. A limited number of components in the station valve yard were also screened for this comparison. The total number of components screened for this comparison at Site 5 was 2509. Only 716 of these were screened using the Ultrasonic Translator Detector.

To minimize bias in the screening process, the leak detection using each of the methods described above was performed independently by different teams. Components were tagged with sequentially numbered tags prior to the start of leak detection. This allowed each leak detection team to record the location of a leak on a data sheet without leaving any indication of where the leak was located. This prevented subsequent leak detection teams from having prior knowledge of where leaks might be located.

Private client sites 1 and 2 had twelve and six natural gas fired reciprocating compressors, respectively. All components were screened using a combination of soap solution and the Bascom-Turner CGI-211. Any leaking components were tagged sequentially. The Ultraprobe 2000 was then taken by an Indaco team member to a subset of the leaking components at each site, and an assessment made of the success with which the instrument could identify leaks at these already tagged components.

The leak detection instruments were calibrated prior to the start of the screening. The TVA-1000 was calibrated and checked using standard mixtures of methane in air (900 ppm, 10,000 ppm (1%) and 25,000 ppm (2.5%) supplied by Scott Specialty Gases (certified accurate to ±2%). The Bascom-Turner CGI-211 instrument was calibrated daily using both 2.5% methane in air and 31% helium in nitrogen (which has the same thermal conductivity as 100% methane, but is safer and more convenient to use). To calibrate these instruments without causing a pressure increase or decrease at the sample inlet, a Tedlar bag was filled with the standard gas and connected to the analyzer inlet. The diluter probe attachment which is commonly used to extend the range of the TVA for screening measurements was also attached to the TVA and calibrated to provide a 10:1 dilution. Span checks using the 1% methane in air were performed on the TVA every 3 to 4 hours. The GMI Gas Surveyor was calibrated using on demand supplies of 2.5% and 50% methane.

When using the TVA-1000 at Site 7, all screening concentrations above 10 ppm were recorded. At Site 5, three different leak definitions (>10 ppm, >100 ppm, and > 10,000 ppm) were used in different areas to determine what effect this might have on the speed of screening and the number of leaks that would be reported. For any leak screening larger than 10,000 ppm, the diluter probe was attached and the leak was re-screened. All leak screening concentrations were recorded on data sheets with the leak number. The time required to perform screening for each set of components was also recorded.

At Site 7, soap solution and CGI-211 screening were performed independently. Open ended lines, flanges with deep crevices, and some components near engine ignition systems cannot be screened with soap solution, but soap was used to screen all other components such as valves and pipe thread connectors. Any components at which bubbles formed were recorded as leaks. All components at Site 7 were screened using the CGI-211. Any components screening above 500 ppm were recorded as leaks. This screening was performed on a “Leak/No Leak” basis, where the presence of a leak was noted but screening concentrations were not recorded. At Site 5, soap solution and screening with the CGI-211 were used in conjunction with each other. In this case, the CGI-211 was used to screen any components that could not be screened with soap.

The Ultraprobe was used as an independent method for ultrasonic leak detection at Site 7 and Site 11. At Site 5, the Ultrasonic Translator Detector operator was provided by the host company. This operator used soap solution to verify that a leak, detected using the ultrasonic method, was present, screened the leak using a “lower explosive limit” leak detector and then recorded the screening concentration. The specifications on the leak detector used to measure screening concentrations during the ultrasonic screening are not available.

Once all of the leak detection techniques had been used to screen the components, the Hi-Flow sampler was used to measure the leak rate of each detected leak. Prior to the field project, the entire Hi-Flow system was calibrated by releasing known flow rates of methane into the inlet of the sample hose. The detectors, used to measure the background and sample stream natural gas concentrations, were calibrated at the site using the same calibration gases and techniques as described above for the TVA- 1000 and the CGI-211.

Leak rates were measured by holding the nozzle of the Hi-Flow sampler within 1 cm of the leak while holding the background probe approximately 5 cm to 10 cm away, depending on the type and size of component tested. This allowed the background concentration to be accurately determined during the leak measurement. A flexible hood or industrial stretch plastic wrap was used to block wind and leak momentum and to direct leak flow into the high flow sampler. The hood and plastic were not used to make an air tight enclosure but only to ensure Hi-Flow sampler capture efficiency. Leak rate measurements at flanges were made by sealing the flange circumference with either duct tape or stretch wrap. Openings were left at opposite sides of the flange for air entry and exit.

Leak rate data were recorded manually on data sheets printed for this purpose. These data included leak tag number, date, a description of the component (type of component and service), Hi-Flow sampler anemometer velocity (which is calibrated to sample flow rate), background concentration, and sample concentration.

Quality assurance was conducted by making replicate measurements using different sample flow rates. Varying the sample flow rate provides data on the success of leak capture. If the leak rate measured by the sampler remains constant as the sample flow is increased, then the leak capture at both sample flow rates was successful. At flanges, replicate measurements were made by reversing the air entry and exit locations.

The number and type of components which were surveyed for leaks were counted at each facility. The categories included flanges, pipe thread connections, tubing connections, gate and needle valves, plug and ball valves, control valves, open ended lines, pressure relief valves, station blowdown vents, compressor blowdown vents, compressor rod packing vents, and unit valve vents. These components counts were used to calculate emission factors for each component category by dividing the total leak rate by the total number of components. The results of the measurement program are presented in the following section.

4. Field Measurement Results

4.1 Ultrasonic Leak Detection

At Site 7, no leaks were detected using the Ultraprobe-2000. Adjustment of the frequency and sensitivity settings and use of the focusing probe attachment did not help distinguish ultrasonic noise generated by leaks from the other ultrasonic noise present. Since ultrasonic waves have high frequencies and short wavelengths, the instrument manual recommended trying to shield the instrument from the competing noise source. Shielding techniques such as the use of the operator's hand or body, the use of a clipboard, or the use of the rubber focusing probe did not improve leak detection. Distances from the instrument to the components surveyed were varied from six feet to two inches. Three different operators tried ultrasonic leak detection without success. The other leak detection methods used at Site 7 found a total of 131 leaks with a total leak rate 191 scfh.

Ultrasonic leak detection at a compressor station is especially difficult because the interfering noise is often inside the systems being surveyed. For instance, gas metering and pressure regulating systems have gas flow across internal orifices which generates ultrasonic noise. High flow rates of gas through valves and other changes in piping sizes also generate ultrasonic noise. These large amounts of background noise being generated from the same location at which components are being surveyed makes the use of ultrasonic leak detection difficult.

Due to the background noise problems encountered at Site 7, further tests were performed at Site 11 to assess the Ultraprobe in a quieter operating environment where no compressors were running. These were the only leak detection comparison tests done at Site 11. Even with the focusing probe attachment in place and with adjustments in the sensitivity setting, the instrument was still hampered by background ultrasonic noise from gas flow through various restrictions in piping. No leaks were found with ultrasonic detection at Site 11, while the use of soap solution and screening with the CGI-211 found 64 leaks with a total leak rate of 79.7 scfh.

Laboratory studies were conducted to provide a second evaluation of the Ultraprobe. Ultrasonic screenings were conducted using a single leak with no wind and minimal competing ultrasonic frequencies in the test area. A 12" length of 1/16" x 0.004" I.D. stainless steel tubing was connected via a regulator to a pressurized cylinder of natural gas. The pressure in the flow line was recorded from the regulator and the flow rate was measured using a bubble meter. The Ultraprobe instrument was pointed in the direction of the test area and then moved toward it at a slow pace. The maximum distance at which the leak produced a response from the instrument was recorded. The maximum sensitivity setting was used during the test. Table 1 shows the results of these laboratory measurements.

Table 1. Ultraprobe- Leak Detection Sensitivity Studies

Line Pressure	Leak Rate (scfh)	Max. Leak Detection Distance	Instrument Sensitivity Setting	Comments
80 psig	0.25	12 ft	Maximum	No focusing probe.
60 psig	0.17	7.5 ft	Maximum	No focusing probe.
40 psig	0.08	0.75 in.	Maximum	Rubber focusing probe required
20 psig	0.04	Not Detected at 0.5 in.	Maximum	No response, even with focusing probe

These results indicate that the instrument worked quite effectively under laboratory test conditions. Leak identification was achieved at distances of 12 feet away from a leak of only 0.25 cfh and at a leak of only 0.08 cfh at 0.75 in. The Ultraprobe clearly has a high sensitivity to even small leaks, although this sensitivity will vary because the amount of ultrasonic noise generated by a leak will change depending on the size of the leak orifice and the resulting velocity.

Based on the results from the laboratory study, further field tests were conducted at two private client sites. A new Ultraprobe- instrument was used at these two sites, as opposed to the rented device used in the previous tests. Initial screening was performed using a combination of soap solution and CGI-211 methane detector. After all leaks had been detected and tagged, the Ultraprobe- was taken by an Indaco team member to each tagged leaking component and tested to see whether it could identify the leak. Table 2 presents the results from this test.

Table 2. Ultraprobe- Leak Detection Comparison Tests Conducted at Two Private Client Sites.

	Total No. of Leaks Detected'	# of Leaks Identified by Ultraprobe	Total Leak Rate[2] (Mcf/yr)	Total Leak Rate from Leaks Identified with the Ultraprobe[2] (Mcf/yr)
Private Client Site 1	71	29 (41%)	2,645	2,376 (90%)
Private Client Site 2	31	17 (55%)	2,081	1,535 (74%)

'Leak detection performed using soap solution and CGI-211 detector.
[2]Leak rate measurements made with the Hi-Flow™ sampler.

Under the conditions of this specific test, the Ultraprobe was successful. Although it only managed to identify 41% and 55% of the total number of leaks detected using soap and CGI-211, these leaks accounted for 90% and 74%, respectively, of the total leak rate from the surveyed components.

Ultrasonic leak detection was also performed at Site 3, using a different instrument, the Ultrasonic Translator. Both this instrument and the instrument operator were provided by the transmission company operating the site. The instrument operator used a combination of soap solution and the Ultrasonic Translator to find leaks. Two members of the Indaco field team tried the Ultrasonic Translator alone without the use of soap solution, but could not find leaks with the instrument or distinguish leaks that had been found previously, by other methods, from the background noise. Because of time constraints on the instrument operator, only 716 components were screened at this site with the combination of soap and the Ultrasonic Translator. Out of these 716 components, the instrument operator found 15 leaks. The team using soap and the CGI-211 found 133 leaks at these same 716 components.

If the 15 leaks found by using the ultrasonic technique at Site 3 were the largest and most important leaks at the components surveyed, then the relatively small fraction (11.3%) of the total number of leaks found using ultrasonic method would be acceptable. However, as shown in Table 3, the total leak rate measured for the 15 components found by ultrasonic (based on Hi-Flow sampler measurements) was 91.2 lb/day, equivalent to 42% of the total leak rate from those components (2 16.5 lb/day). Consequently, less than half of the total leakage from these components was found using the ultrasonic technique in this case.

Table 3. Results of Screening Methods at Site 3 - Components Screened by Ultrasonic Translator

Leak Detection Method	Ultrasonic	Soap/CGI-211
Total Leaks Found (716 components surveyed)	15	133
Emission Rate (lb/day) measured by Hi-Flow Sampler	91.2 **(42.1% of total)**	216.5 **(100% of total)**

Based on the results from this study it seems that ultrasonic screening can detect leaks at transmission compressor facilities, but that the results are varied and susceptible to interference from background noise. Surveys conducted at Sites 7 and 11 indicated that under both quiet and noisy background environments the Ultraprobe could not detect any leaks. The results from the private client sites indicate that the Ultraprobe could be successful, and that the poor results from the previous study may have been due to a defective instrument. It is important to note that the results from both the private client sites and Site 5 are under ideal conditions, in that ultrasonic screening was not the sole screening device, but was used after or in conjunction with other screening instruments. Consequently, ultrasonic screening appears to be effective if used in conjunction with other leak detection methods. False positives due to internal noise can then be eliminated and areas with high levels of background ultrasonic noise that prevent the use of the ultrasonic leak detection can be screened using other techniques. Ultrasonic techniques also can be used to check for internal valve leakage.

4.2 Laboratory Testing of Leak Detection Solutions

To determine the importance of the composition of leak detection solutions on their effectiveness for leak detection, nine commercially available leak detector solutions and five “homemade” solutions were tested under laboratory conditions. Commercial grade natural gas was used to simulate a leak of approximately 0.5 scfh at a 1/4" pipe thread fitting. This leak was monitored during the experiment using the Hi-Flow sampler to ensure the leak rate was constant during the test. A fan was used to create a constant wind speed of 9.5 mph, which was monitored using a Velocicheck Model 8400 hot wire anemometer (TSI, Inc.). A syringe was used to inject 1 cc of leak detector solution onto the leaking fitting. The maximum size of the bubble mass that formed (lengthwise blowing away from the fan), the duration of time that bubbles larger than 0.2 in. were present, and the duration of time that any bubbles were present were recorded. The maximum size of the bubble mass formed and the amount of time that bubbles remain that are larger than 0.2 in. is probably the best indicator of how likely a leak will be found using a particular solution, in particular it indicates the amount of time after the component is checked that enough bubble activity will be present to be seen during a second check. The results of this test are presented in Table 4.

The largest initial bubble masses were formed by Episeal Leak Seak, Nupro Snoop, and the Sherlock Low Temperature solutions. Of these, the Episeal Leak Seak had bubbles larger than 0.2 in. remain the longest. The solutions with ethylene glycol (Calgon, Episeal, Nupro Real Cool Snoop, Sherlock Low Temperature) tended to continue small bubble activity for the longest periods. However, these small bubbles would only be visible on very close inspection of each component. The Calgon and Precissionaire products were more viscous solutions. These tended to form bubbles slower and the bubble activity tended to end within one to two minutes. However, even under the laboratory wind speed, the bubbles that had formed remained near the leak for extended periods of time, up to 10 minutes for the Calgon, and approximately 6.5 minutes for the Precissionaire. This would allow personnel to spot the leak for a considerable amount of time after the bubbles had stopped forming. The Sherlock Regular, Sherlock Type CG, Nupro Snoop, and Nupro Real Cool Snoop all had visible bubbles last for a period of one minute to one and one half minutes, which is significantly shorter than many solutions but should be adequate for leak detection. Alltech Leak Check had the worst performance with the smallest bubble size (0.8 cm) and the shortest duration of visible bubbles. It does not appear suitable for field application. However, it is important to note that this solution is targeted for laboratory use and has been specifically formulated not to leave residue on analytical equipment.

Excluding the Alltech Leak Check, all of the other solutions appear to meet suitable minimum requirements for leak detection under field conditions. Factors affecting selection include the ambient temperature, which might require non-freezing solution. However, these usually contain ethylene glycol which makes these liquids very slippery and care must be exercised to avoid a slipping hazard for facility personnel. Additionally, some formulations may contain flammable substances such as isopropyl alcohol (in this case, the Sherlock Type CG) which should be avoided at natural gas facilities.

Price, however, may help in choosing a solution. Again excluding the Alltech Leak Check, four of the commercial solutions ranged in price from $42.90 to $56.40, while the other four ranged from $7.50 to $8.85. Of the commercial solutions, the Episeal Leak Seek appears to have the best all around value, being moderately priced, suitable for a relatively cold temperature range (down to -10 “F) and forming both large and long lasting bubbles.

The value of using “homemade” leak solutions was also tested. Children’s bubble soap (Mr. Bubbles brand) and shampoo (Green Prell) were mixed with water to create leak test solutions. The results are also shown in Table 4. Solutions of Mr. Bubbles and water of 5%, 10%, and 20% were tested; pure Mr. Bubbles was also tested. Concentrations greater than 5% increased the initial bubble size somewhat but tended to reduce the duration of time that visible bubbles existed. Two solutions of Prell in water were tested. Both had initial bubble masses larger than Mr. Bubbles; bubbles from the 5% solution tended to last longer than the 2% solution. Ethylene glycol or propylene glycol (considered less toxic) could be added to these solutions to decrease the freezing point if necessary.

Table 4. Comparison of Bubble Characteristics of Leak Detection Solutions

Detector Solution	Temperature Range (as stated by manufacturer)	cost ($/gallon)	Maximum Size of Bubble Mass (in)	Duration of Bubbles > 0.2 in (min:sec)	Duration of Any Bubbles Presence (min:sec)
Alltech Leak Check	+30"F-+200"F	$86.67	0.8	0:30	0:40
Calgon Gas Leak Detector 41822	> 5°F	$52.17	2.0	10:00	10:00
EpiSeal Leak Seek	-10°F	$8.40	2.5	4:30	9:00
Nupro Real Cool Snoop	-65°F to 200°F	$56.40	1.5	1:30	8:00
Nupro Snoop	Temp: 27°F to 200°F	$42.90	2.5	1:00	1:15
Precissionaire Pro-Chem Fluorescent Leak Detector	"Non-Freezing"	$48.00	1.5	6:30	6:30
Sherlock Low Temp	-10°F	$8.85	2.5	2:50	10:00
Sherlock Regular	"Above Freezing"	$7.50	2.0	1:00	3:00
Sherlock Type CG	Not Speciifed	$ 7.50	2.0	1:20	2:15
5% Mr. Bubble in Water	Approx. 32°F	$0.63	1.2	1:45	2:00
10% Mr. Bubble in Water	Approx. 32°F	$0.76	1.5	1:30	2:15
20% Mr. Bubble in Water	Approx. 32°F	$1.01	1.5	1:00	2:00
Pure Mr. Bubble	Approx. 32°F	$1.56	1.5	0:45	2:00
2% Prell Shampoo in Water	Approx. 32°F	$0.91	2.0	1:15	2:00
5% Prell Shampoo in Water	Approx. 32°F	$1.52	2.0	2:00	2:30

The performance of the homemade solutions was similar to many of the commercial solutions and acceptable for conducting leak surveys. Additionally, the price is 5 to 10 times lower than even the low cost commercial solutions. Also significantly, it appears that although the type and amount of soap used may vary the performance of the solution, the variation is not significant enough to require careful mixing of each batch of solution.

We do not routinely track the amount of leak solution used during our surveys. However, by measuring the amount of solution sprayed out of a typical bottle in each spray, and estimating the number of times a component might be sprayed for detection, we can estimate the approximate use of solution at a facility. Based on past components counts, a 5000 component facility would have on average 4000 components which could be checked with leak detector solution. If each component were sprayed an average of three times, approximately 6 gallons of solution would be used. The cost of this solution could range from less than $5 to over $340, depending on which solution was chosen.

4.3 TVA-1000, Gasurveyor, CGI-201, and Soap Surveying Results

At Site 7, eight areas within the compressor facility were set aside for the leak detection survey. Table 5 presents the length of time required for each method to survey a particular area, based on a "Leak/No Leak" classification. These screening times should only be used for method comparison. Actual screening times at other sites will vary due to time required for orientation, identification of process streams, calibration of equipment, and the accessibility of components.

The screening times for each method vary considerably between the different areas of the facility due to differences in accessibility to components as well as background concentrations of natural gas. High background concentrations may make it appear that some components are leaking even though they are not. The fuel gas system in the meter building was the fastest area to screen because of its smaller components, open access, and low background concentrations. In this area, the standardized screening times for the CGI-211, Gasurveyor and TVA instruments were similar. Conversely, the compressor area of Unit 4 took the longest for all methods to screen because access to this area was very difficult. This area had a larger number of leaks, movement was limited by the cramped spacing of the compressors, and large background concentrations (= 400-600ppm) were present. The higher sensitivity of the TVA- 1000 may have been a benefit in this environment since the screening times for the CGI-211 and Gasurveyor units which were on average 43% and 25% slower, respectively, than the TVA-1000. Screening times for the CGI-211 and TVA in the suction/discharge lines of units 1 and 4 were fairly similar. The slower screening times within the Unit 1 suction/discharge valve area are also attributable to space limitations and difficult access. Screening times will also vary with different instrument operators.

Table 5. Leak Detection Screening Times for Site 7, based on Leak/No-Leak Classification

			Normalized Screening Time (Components/hr)			
Survey Area	Component Pressure[3]	Total No. of Leaks Detected[4]	SOAP[5]	CGI-211	GMI	TVA-1000
Meter Building (Inside)	Fuel Gas	14	375	250	333	375
Unit 4: Fuel Gas (Inside)	Fuel Gas	8	750	500	500	600
Unit 4: Compressors (Inside)[1]	Line	62	91	44	50	63
Unit 4: Suction/Discharge (Outside)[2]	Line	13	273	140	200	154
Unit 1: Compressors (Inside)[1]	Line	10	375	143	154	162
Unit 1: Suction/Discharge (Outside)[2]	Line	5	176	87	140	100
Unit 7 (Inside and Outside)[1]	Fuel Gas	19	400	200	207	176
Average for Method Over All Survey Areas			**349**	**195**	**226**	**233**

[1]Unit 1 and 4: Reciprocating engines; Unit 7: Turbine
[2]Windy Conditions (= 15-20 mph); Temperature 30-35 ^{0}F (snowing)
[3]Fuel Gas Pressure = 130 psi; Average Line Pressure'= 650 psi
[4]Total number of leaks detected by all methods
[5]No flange or open ended line components included in soap screening statistics

Table 6 presents the success rate of each leak detection method, sorted by leak size. The average screening time for each method is presented in the last row for comparison. A total of 131 leaks were detected by all methods in the seven areas of Site 7. Sixty-two of these leaks were below the Hi-Flow sampler measurable limit (= 0.1 scfh).

Table 6. Comparison of Leak Detection Techniques at Site 7, based on a Leak/No-Leak Classification

Leak Rate Size Range (scfh)	Total No. of Leaks Detected Using All Methods	No. of Leaks Found by Each Method[1]			
		CGI-211	TVA-1000	Gasurveyor	Soap
2 - 42	17	15 (88%)	16 (94%)	9 (53%)	15 (88%)
0.2 - 2	27	21(78%)	20 (74%)	18(68%)	17 (62%)
0.1 - 0.2	26	16(62%)	17 (65%)	12 (46%)	14 (53%)
< 0.1	62	25 (40%)	39 (63%)	14 (23%)	12 (19%)
Average Screening Rate (components/hour)[2]		195	233	226	349

[1]Percentage of total leaks found in parentheses
[2]Screening time based on components per man-hour

The CGI-211 and TVA-1000 success rates are similar for all leak ranges, except the smallest range (leaks lower than 0.05 1/min). At that point, the TVA-1000 found approximately 50% more leaks than the CGI-211, possibly due to better sensitivity. Since the sensitivity for the Gasurveyor is better than the CGI-211, the lower detection success rate of the Gasurveyor may be due to operator inexperience. Within the Unit I suction/discharge valve area the soap, TVA and CGI-211 had 80% detection rates while the Gasurveyor had a 40% success rate. For the Unit 4 suction/discharge valve area the soap and CGI-211 methods had a success rate of 60%, and the TVA a success rate of 1OO%, while the Gasurveyor detected only 31% of the leaks. During any screening survey, leak detection success rates can vary depending on operator experience.

On the average, soap screening was 50% faster than any other leak detection method. The TVA- 1000 was the next fastest method, but the difference between its rate of screening and the Gasurveyor is only 3%, and only 16% faster than the CGI-211. The increased sensitivity and faster response time of the TVA- 1000 was put to best use in the area of Unit 4 to differentiate leaks where there was a high background concentration.

As discussed in Section 4.1, a key factor in determining the success rate of a leak detection method is not just the total number of leaks found but also whether the leaks found represent the most significant leaks at the site and consequently the majority of the total leak rate. Table 7 compares the percentage of the total leak rate found by each method used at Site 7, based on a leak/no-leak classification.

Table 7. The Effectiveness of Leak Detection Methods Based at Site 7

Leak Detection Method	Total Leak Rate Found By Each Detection Method (Measured by Hi-Flow Sampler; scfh)	Percentage of Total Leak Rate
TVA-1000	179	93.6%
CGI-211	184	96.4%
Soap	78.1 (99.9)[1]	78.2%
Gasurveyor	139	72.9%
Total for all components detected	191 (99.9)[1]	100%

[1]Not all components could be surveyed using soap; Total leak rate for components that were surveyedusing soap was 99.9 scfh.

From this comparison, both the TVA-1000 and the CGI-211 were highly successful, finding 93.6% and 96.4% of the total leak rate from the surveyed components. Even the soap screening and the Gasurveyor, which had relatively less success in the total numbers of leaks found were still successful in finding the most important leaks at the site.

The Gasurveyor data at Site 7 was collected with the help of gas transmission company personnel who are conscientious, but generally do not spend the majority of their time performing leak surveys. Due to the uncertainties associated with inexperienced leak surveyors and the corresponding impact on leak detection study results, all leak detection, at Site 5, was performed by Indaco with the exception of the ultrasonic screening discussed in Section 4.1. Table 8 presents the results of the leak detection comparison at Site 5. Aside from the ultrasonic method, the comparison at this site focused on screening with the TVA- 1000 versus using soap screening and the CGI-211 in tandem. As discussed previously, the average screening times presented should be used for comparison only. Other tasks during leak detection surveys significantly slow actual leak detection programs at any given site.

Table 8. Comparison of Leak Detection Methods at Site 5.

Leak Rate Range (scfh)	Total No. of Leaks Detected by All Methods	No. of Leaks Found by Each Method[1]	
		Soap/CGI-211	TVA-1000[2]
2 - 42	33	33 (100%)	33 (100%)
0.2 - 2	92	92 (100%)	86 (93.5%)
0.1 - 0.2	35	34 (97.1%)	34 (97.1%)
< 0.1	78	78 (100%)	75 (96.2%)
Average Screening Time (components/hour)[3]		350	255

[1]Percentage of total leaks found in parentheses
[2]Screening performed using US EPA Method 21
[3]Screening time based on components per crew-hour (two person crew)

At this site, the leak detection success rate exceeds 95% in almost all cases. Consequently, the lower success rates at Site 7 may be due to the difficult access at that site and the inexperience of some operators used at that site. The combination of soap and CGI-211 screening had a slightly higher success rate for the percentage of leaks found than the TVA- 1000, even though the soap/CGI-211 method was almost 40% faster.

Some other factors affecting the screening speed of the TVA-1000 were also noted. Screening indoors with the TVA-1000 was performed approximately 9% faster than screening outdoors, probably due to less variability in screening concentrations due to wind. Screening was also conducted using two criteria for leak detection. The first was a careful quantification of screening concentration for any leaks that screened greater than 100 ppm, using the US EPA Method 21 approach. The second was yes/no leak determination, with the leak definition at 10,000 ppm. When using just a yes/no determination, screening was performed 42% faster than trying to quantify a screening concentration using US EPA Method 21. This indicates that at facilities with process streams other than primarily methane (such as natural gas production and processing facilities, refineries, and chemical plants) where an FID or PID system might be necessary instead of soap or catalytic detector, the screening could still be conducted more efficiently by using a yes/no leak definition followed by actual leak rate measurements with the Hi-Flow sampler rather than using screening correlations. The faster screening method would offset the extra time needed for the Hi-Flow measurements.

4.4 Leak Rate Estimates Using Emission Factors and Correlation Equations

As discussed in Section 2.2, past estimates of fugitive emissions from leaking components have relied either on emission factors or screening correlations. Table 9 presents the results of applying these approaches to the two sites where screening data were collected during this project. This analysis is for standard components only and does not include the large emitters at compressor sites such as rod packings and unit valve leakage.

Table 9. Comparison of Fugitive Emission Estimates

Emissions Method	Leak Rate at Site 7 (lb/day) (1310 components)	Leak Rate at Site 5 (lb/day) (2516 components)
Emission Factors (EPA 1995)	88.8	237.8
Screening Correlations (10,000 ppm pegged source; API 1996)	103.4	333.0
Hi-Flow Sampler	223.4	373.4

At both sites, the use of emission factors underestimated emissions significantly. At Site 7, the emission factors estimate was only 40% of the actual emissions (determined by Hi-Flow sampler measurements). At Site 5, the emission factor estimate was 63% of the actual emissions. The use of screening data and correlation equations improved the estimates. The correlation equation estimates were 45% and 89% of the actual emissions at Site 7 and 5, respectively.

If estimating emissions is the only goal, then using screening data can be successful in many cases, especially as the number of components surveyed increases. However, because the uncertainty associated with any one point of the correlation equation is at least three orders of magnitude, screening data is not acceptable for making repair decisions. Figures I, 2, and 3 illustrate this point, by identifying the top 160 leaks sorted by correlation equation based leak rate. These figures compare the leak rate estimated by screening correlation (using FID screening data) to the actual leak rate measured by Hi-Flow sampler at Site 5. If screening data were the basis for repair decisions, then the leaks estimated as the largest from the screening data would be repaired first. However, the actual leak rate data collected by the Hi-Flow sampler is shown next to each of the screening data estimates, and as seen in Figure 1, most of the leaks indicated for repair by the screening data are not cost effective to repair. This trend continues in Figure 2. In Figure 3, some leaks which would be ignored by the screening data are shown to have potential for the recovery of lost gas.

Figure 1. Comparison of Leak Rate Estimates using Correlation Equations and Hi-Flow Measurements -Sorted w.r.t Emission Factor Size

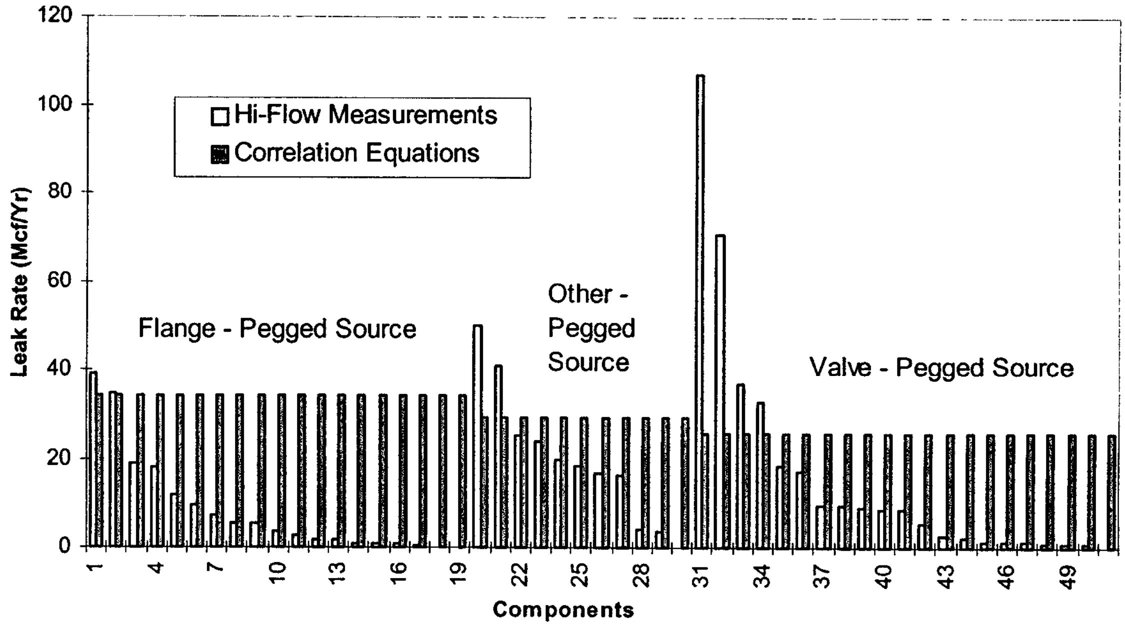


Figure 2. Comparison of Leak Rate Estimates Using Emission Factors and Hi-Flow Measurements - Sorted w.r.t Emission Factor Size

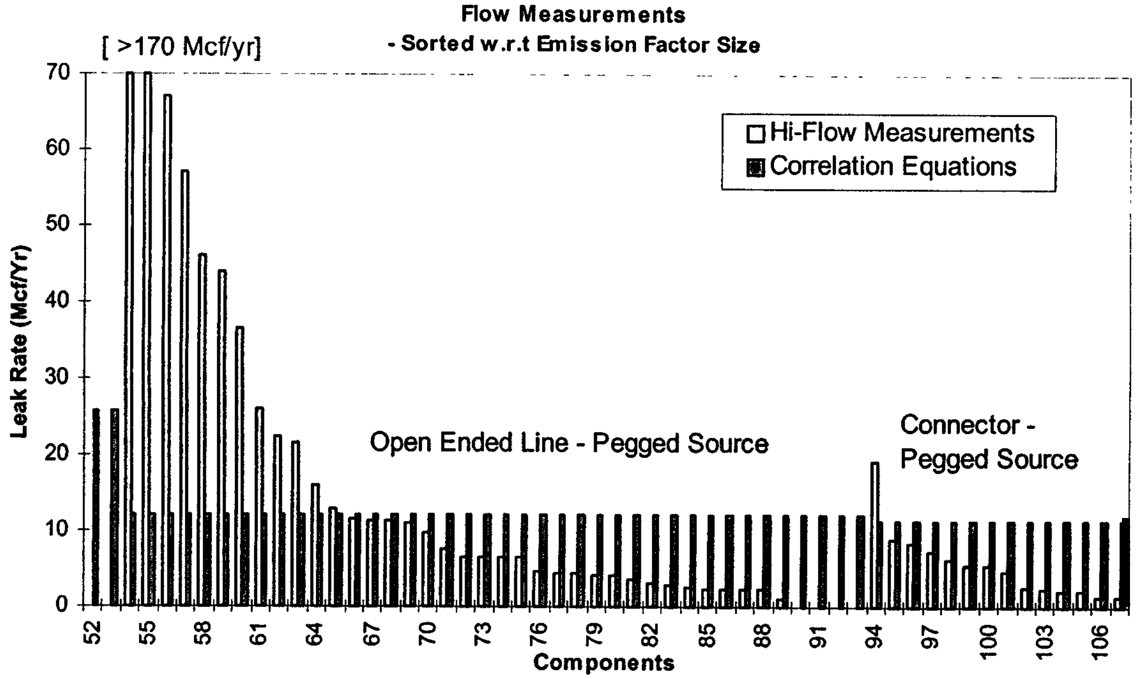
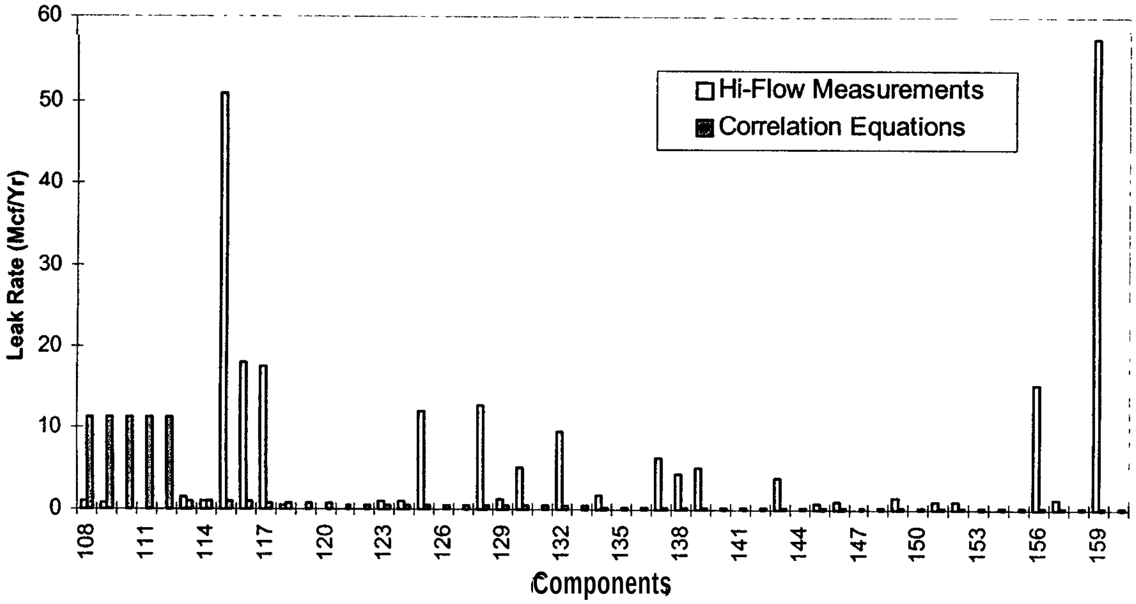


Figure 3. Comparison of Leak Rate Estimates Using Emission Factors and Hi-Flow Measurements - Sorted w.r.t Emission Factor Size



If screening data were used at Site 5 to determine the repair criteria for fixing leaks, many insignificant leaks would be repaired (Table 1O). Assuming all leaks that screened greater than 10,000 ppm were fixed, 112 components would require repair, resulting in a reduction in total leak rate of 62%. However, using actual leak rate data, if a repair criteria of 30 Mcf/yr or greater were designated, only 22 leaks would need to be fixed, corresponding to a total leak rate reduction of 66%. Clearly, without actual leak rate data, maintenance resources will be wasted on repairing leaks which are not significant, while potentially missing leaks that do contribute to the total leak rate.

Table 10. Comparison of Using Different Repair Criteria for Leak Fixes.

Repair Criteria	# of Components	% of Total Leaks Detected	Leak Rate Attributable to Repair Criteria Leaks[2] (Mcf/yr)	% of Total Leak Rate Measured*
> 10,000 ppm (pegged source; API 1996)	112	47%	1,766	62%
> 30 Mcf/yr ($60/yr)[1]	22	9%	1,880	66%

[1]Cost of gas = $2/Mcf
[2]Leak rate based on Hi-Flow[TM] measurements

5. Summary and Recommendations

Leak detection and quantification techniques were tested at natural gas transmission compressor stations to determine the time required to perform each method and the effectiveness of each method. The use of flame ionization detectors, catalytic oxidation/thermal conductivity detectors, leak detection bubble solution, and ultrasonic detection were tested during this work. The amount of time to perform each method, the number of leaks found, and the total leak rate were determined for each technique.

The use of a combination of homemade soap solution and a catalytic oxidation/thermal conductivity (CO/TC) detector when applied by experienced personnel was found to be as effective in the number of leaks found as using the more sensitive flame ionization detectors (FID). Moreover, the use of soap solution and the catalytic oxidation/thermal conductivity detector could screen 40% more components in the same amount of time as an FID, even though initial investment in the soap and CO/TC method is approximately 10% to 20% of the cost of an FID.

A variety of commercial and homemade leak detection solutions were also tested in the laboratory to determine their effectiveness. Although the performance of these solutions did vary in terms of the size and durability of bubbles formed, most of the solutions were found to be satisfactory and the performance was not related to price. The best performing commercial solution was a factor of 10 less expensive than the most expensive solution. Homemade solutions from children's bubble soap or shampoo were also found to be effective and could be made for an average of a factor of 10 less than the cheapest commercial solutions.

Ultrasonic screening can detect leaks at transmission compressor facilities, but that the results are varied and susceptible to interference from background noise. At two of the test sites no leaks could be detected. However, under laboratory conditions the instrument was found to be very sensitive, and was able to identify a leak of 0.25 scfh at a distance of 12 feet. During further testing at three more sites, ultrasonic screening was utilized after or in conjunction with other screening instruments. Under this scenario, the ultrasonic instrument proved more successful. Consequently, ultrasonic screening appears to be effective if used in conjunction with other leak detection methods. Areas with high levels of background ultrasonic noise that prevent the use of the ultrasonic leak detection can then be screened using other techniques.

Although emission factors and correlation equations could estimate average leak rates within 45% to 89% they were not effective at estimating leak rates for individual components. It is essential to accurately determine the leak rates for individual components to achieve cost effective leak reduction. When leak rates were estimated from screening concentrations using correlation equations, the wrong components were targeted for repair. At one of the sites surveyed, if all leaks that screened as a "pegged source" (> 10,000 ppm) were fixed, 112 leaks would need to be repaired, producing a corresponding leak rate reduction of only 62%. However, using actual leak rate data, if all components leaking greater than 30 Mcf/yr ($6O/yr at $2/Mcf) were repaired, only 22 leaks would require fixing. The corresponding total leak rate reduction would be 66%.

6.0 References

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Appendix II

Leak Rates from Compressor Rod Packings at Natural Gas Transmission Stations

1. Introduction

Large leak rates from natural gas transmission compressor stations continue to present both an economic and an environmental challenge to the natural gas industry. To further assess the leak rates from these facilities and to determine the most cost effective methods of mitigating this leakage, a cooperative leak rate survey program is currently being sponsored by PRC International (PRCI), the Gas Research Institute (GRI), and the U.S. Environmental Protection Agency (EPA). The goals of this program are to refine emission factors for the transmission segment of the gas industry, determine key areas of leakage to address, and to evaluate possible mitigation strategies.

Leak rate measurements sponsored by GRI have previously shown that large leak rates may occur across the unit valves of compressors that are off-line and depressurized (Howard et al., 1995a). In response to this problem, many facilities now leave reciprocating compressors pressurized when off-line. Unfortunately, leakage across rod packings is often significant on both running and idle compressors.

This report presents measurements of leak rates across rod packings made at ten natural gas transmission stations during the PRCI/GRI/EPA cooperative program, as well as data from measurements made at several private client facilities. These measurements were conducted to assess rod packing performance and to determine the effectiveness of current leak mitigation efforts.

2. Leak Rate Measurement Techniques

Leak rates across rod packings were measured, during this program, using a combination of techniques. The Hi-Flow™ sampler (Howard et al., 1995b) was used for leak rates that were less than 8 scfm. The Hi-Flow sampler uses a high flow rate of air and a partial enclosure to completely capture the gas leaking from the component. A catalytic oxidation/thermal conductivity sensor is used to measure the sample concentration in the air stream of the Hi-Flow system.

For leak rates exceeding 8 scfm, measurements were made using either an intrinsically safe hot wire anemometer or with a bag expansion technique. The hot wire anemometer was used to perform velocity traverses across a vent opening from which an average velocity is calculated. The flow rate from the vent was then calculated as the average velocity multiplied by the cross sectional area of the vent. The hot wire anemometer automatically corrects the velocity measurement to standard temperature conditions (70°F). The composition of the vent gas is also monitored using a catalytic oxidation/thermal conductivity screening instrument (Bascom-Turner CGI-211). Based on these readings, the anemometer was also corrected for the difference in thermal conductivity between natural gas and air.

The bag expansion technique used bags of known volume that have been constructed from anti-static plastic. These bags were attached to the vent and the time required to fill the bag was recorded. The gas temperature and ambient temperature were measured by an intrinsically safe thermocouple (Cole-Parmer Digi-Sense Model No. 8528-12) and were used with ambient pressure to convert the volumetric flow to standard conditions (70 “F, 1 atm). As with the anemometer measurement, the composition of the gas flow was monitored using a catalytic oxidation/thermal conductivity instrument.

3. Rod Packing Overview

A typical compressor rod packing consists of a series of rings, usually constructed of either brass, Teflon, or steel. These rings fit around the compressor cylinder rod to seal process gas into the compressor cylinder and prevent its flow to atmosphere through the compressor distance piece. Within the packing case, the rings are held in place by a series of packing cups. Because the rings form a seal against the compressor rod and packing cup face, it is important that both components are free from imperfections. Compressor rod packing rings are typically constructed of segments spring loaded against the compressor rod. This characteristic allows for easy installation around the rod, allows the rod to move freely back and forth within the packing, and theoretically maintains a tight seal as the rings wear.

Imperfections or wear in the rings and/or compressor rod mating faces, or misalignment of the rings or case can allow leakage. A rod packing vent is placed in each system to allow leakage out of the system. However, natural gas may also leak into the distance piece either along the rod or from the gasket at the end of the packing case. Some systems vent the rod packing vent into the distance piece while others have a separate packing vent. Where possible, separate measurements at the rod packing vent and the distance piece vent were made. In some cases, the measurement from the distance piece vent represents both leakage along the rod and from the packing vent. Additionally, measurements were taken at individual compressor cylinder packings where ever possible to quantify leakage from individual rod packings. At Sites 1,5 and 7, individual cylinder vent couplings could not be broken so measurements were taken for the whole unit.

4. Field Measurement Results

4.1 Summary

A summary of the characteristics of the compressors surveyed is presented in Table 1. Gas inlet pressures varied from 155 psig to 670 psig while outlet pressures varied from 525 psig to 865 psig. Gas outlet temperatures ranged between 71°F and 125°F with the exception of Site 1, which reached an outlet temperature of 200°F. Almost all sites used C. Lee Cook brand packing and there was an almost equal division between sites using bronze or bronze/Teflon packing. However, bronze packings outnumbered bronze/Teflon packings by a factor of two to one.

Rod packing leak rates were measured when compressors were both running and idle but still pressurized. Several of the sites have had measurements conducted at quarterly intervals to examine the performance of rod packings over time. Repairs were also implemented at some sites.

Table 1. Facility Characteristics.

	In P/ Out P (psi)	In T/ Out T (°F)	Engine Brand	#. of Units	Engine (RPM)	Engine (HP)	Rod Size (inch)	Bore Size (inch)	Stroke Length (inch)	Packing Type	Packing Brand
Site 1	155/525	50/200	Cooper Bessemer	13	250	2000	4"	15.25"	20"	Steel/Bronze	C. Lee Cook
Site 2	550/800	75/125	Clark (V8-8)	7	300	1800	3"	—	—	Bronze	C. Lee Cook
	550/800	75/125	Clark (TLA-6)	3	300	2100	—	—	—	Bronze	C. Lee Cook
	550/800	75/125	Clark (TCB-10)	3	300	3400	—	—	—	Bronze	C. Lee Cook
	550/800	75/125	Clark (TCB-16)	2	300	5500	4.5"	—	—	Bronze	C. Lee Cook
Site 3	400/750	72/125	Wyatts (W-64)	4	750	1000	2"	6"	6"	Bronze	C. Lee Cook
Site 4	625/800	76/135	Clark (TCA-6)	7	300	2000	4"	17"	19"	Bronze/Teflon	C. Lee Cook
Site 5	670/865	46/83	Cooper Bessemer	4	250	2000	4"	16"	18"	Bronze/Teflon	C. Lee Cook
	670/865	46/83	Cooper Bessemer	1	330	4000	4"	14.25"	20"	Bronze/Teflon	C. Lee Cook
	670/865	46/83	Cooper Bessemer	1	330	2250	3"	15"	14"	Bronze/Teflon	C. Lee Cook
Site 6	670/870	70/105	Ingersol-Rand	8	330	2000	3.5"	12.75"	15"	Bronze	CeCo
Site 7	600/825	38/71	Clark (TLA-10)	3	300	3600	4	17.5	19	Bronze	C. Lee Cook
	600/825	38/71	Clark (TCV-16)	2	300	6000	4.5	18	19	Bronze	C. Lee Cook
Site 8	450/600	55/110	Clark	2	300	4000	4.5"	21"	19"	Bronze/Teflon	C. Lee Cook
	450/600	55/110	Cooper Bessemer	1	315	10000	4.75"	19"	20"	Bronze/Teflon	C. Lee Cook
Site 9	550/710	67/120	Worthington ML-14	2	310	4000	4.5"	15.5"	18"	Bronze/Teflon	C. Lee Cook
Site 10	740/940	—	Cooper Bessemer	5	330	2000	3"	16"	14"	Bronze	C. Lee Cook
	740/940	—	Dresser Rand	1	330	2400	4"	16.5"	15"	Bronze	C. Lee Cook
	740/940	—	Dresser Rand	2	330	3680	4.5"	21"	19"	Bronze	C. Lee Cook

Table 2 presents the packing seal emission factors for each site, based on first quarter measurements. The average leakage from packing seals on running compressors was 870 ± 250 Mcf/yr, and on idle/pressurized compressors was 1,270 ± 550 Mcf/yr. The total leakage from all rod packings surveyed at these ten sites was 203,700 Mcf/yr, equivalent to a loss of $407,4OO/yr at $2/Mcf. The average loss per site was 20,400 Mcf/yr, equivalent to $40,800 per site.

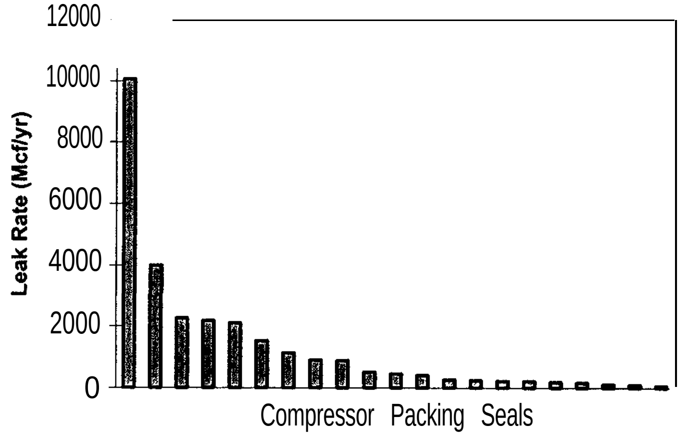
Table 2. Summary of Emission Factors per Facility

	Running Compressors		Idle/Pressurized Compressors	
	# of Seals	Emission Factor (Mcf/yr/packing seal)	# of Seals	Emission Factor (Mcf/yr/packing seal)
Site 1	—	—	12	590
Site 2	55	180	4	195
Site 3	8	110	8	120
Site 4	21	1,340	—	—
Site 5	13	1,320	2	1,410
Site 6	32	880	—	—
Site 7	24	1,270	4	1,850
Site 8	10	2,670	8	3,950
Site 9	—	—	8	320
Site 10	11	830	—	—
Total =	174	870 ± 250[1]	46	1,270 ± 550[1]

[1]Emission factors with associated 95% confidence levels.

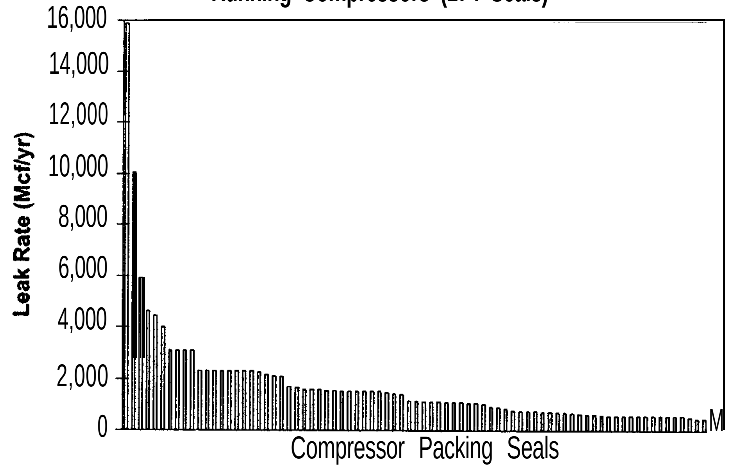
Figure 1 shows the distribution of individual leak rates from rod packings at Site 4, as measured during the first quarter. As with almost all leak distributions observed at compressor stations, the majority of the leakage came from a small percentage of the packing. The total leakage from the individual packings surveyed and shown in Figure 1 was 28,000 Mcf/yr, equivalent to $56,00O/yr at $2/Mcf. The single largest packing leak accounted for 36% of this leakage (10,000 Mcf/yr; $2O,OOO/yr). The largest 10% of these leaks (2 packing seals) accounted for 50% of the total leakage, while the largest 20% accounted for 66% of the total leakage.

Figure 1.
Site 4 - Packing Seal Leak Rate Distribution



Similar distributions can be noted on a system wide basis. Figure 2 illustrates the distribution of packing seal leak rates from all running compressors. Of the 174 seals measured during the first quarter, the top 10% of these leaks (17 packing seals) accounted for 49% of the total leak rate, while the largest 20% accounted for 70% of the total leakage. Clearly, by identifying the largest leaking seals significant emissions can be reduced. To achieve that goal, many facilities are instigating packing vent monitoring. At site 5, packing leakage was measured, by facility personnel, from the packing cup vent using a dry gas meter. The total leakage attributable to the packing seals was 4,060 Mcf/yr. However, this measurement did not account for distance piece leakage. Measurements that were conducted by Indaco at the same site showed that the combined packing cup and distance piece leakage totaled 19,930 Mcf/y, approximately five times more than the packing cup leakage alone. Table 3 illustrates the distribution in leakage from packing cup and distance piece vents on running compressors. Measurements conducted at two sites during this study, as well as at six private client facilities, indicate that distance piece leakage typically accounts for approximately 30% of the total leakage from the compressor packing seals.

Figure 2. Leak Rate Distribution
- Running Compressors (174 Seals)



Furthermore, in measurements conducted for private clients, leakage from the distance piece has in some instances ranged from 5,000 Mcf/yr to 50,000 Mcf/yr without showing significant packing cup vent leakage. These higher values represent not only significant losses of unaccounted for gas, but may also present a safety hazard due to the possibility of creating back pressure of gas against the wiper packing into the crankcase, which might result in gas entering the crankcase. We do not know what leak rates constitute a risk for this scenario. However, leak rates into the distance piece have exceeded 10,000 Mcf/yr (20 scfm) at 10% of the facilities we have surveyed as part of this program and other programs for private clients. At 4% of these facilities these leak rates have exceeded 45,000 Mcf/yr. Consequently, it is important that rod packing leakage be monitored on a routine basis, both from the packing cup and distance piece vents.

Table 3. Distribution of Leakage from Packing Cup and Distance Piece Vents on Running Compressors

Site	# of seals	Packing Cup Leakage (Mcf/yr)	Emission Factor (Mcf/yr/Packing Cup)	Distance Piece Leakage (Mcf/yr)	Emission Factor (Mcf/yr/Distance Piece)
Site 4	21	20200	960	7800	370
Site 6	32	13000	405	15300	480
Private Client Site 1	12	7400	620	5300	440
Private Client Site 2	8	3600	450	1900	240
Private Client Site 3	8	5200	650	1150	145
Private Client Site 4	39	13150	340	5700	145
Private Client Site 5	18	23700	1320	3200	180
Private Client Site 6	33	25200	765	12400	375
Average =			**690**		**300**
% Distribution =			**70%**		**30%**

4.2 Floating Compressors at Fuel Gas Pressure

The results from Table 2 indicate that the average packing seal leakage while the compressor is idle but pressurized is 45% larger than when it is running. Based on these observations, tests were conducted to determine if "floating" idle compressors at fuel gas pressure (70 to 100 psi) instead of at full pressure (700 to 900 psi) would reduce leakage. Table 4 details tests conducted at Sites 4 and 6. At Site 4, measurements were performed during the first and second measurement quarters.

Table 4. Compressor Packing Seal Measurements while the Compressor is Idle/Pressurized - at Full Pressure (700-900 psi) and Fuel Gas Pressure (100 -120 psi) Conditions

		Full Pressure (700-900 psi)		Fuel Gas Pressure (100-120 psi)		
Site	# of Seals	Total Leak Rate (Mcf/yr)	Emission Factor (Mcf/yr/Seal)[1]	Total Leak Rate (Mcf/yr)	Emission Factor (Mcf/yr/Seal)[1]	Average Reduction[2]
Site 4 - 1st Quarter	13	13,300	1,025 (695 psi)	5,460	420 (95 psi)	600 ± 1,070
Site 4 - 2nd Quarter	9	9,180	1,020 (695 psi)	4,680	520 (95 psi)	600 ± 540
Site 6	4	7,470	1,870 (870 psi)	2,660	665 (120 psi)	1,200 ± 960

[1]Pressure at which the packing seal measurement was performed in parentheses.
[2]Emission factors with associated 95% confidence levels.

The packing seal leakage under fuel gas pressure conditions was significantly reduced. The average reduction in leakage per seal was 600 Mcf/yr at Site 4, and 1200 Mcf/yr at Site 6. However, average leak rates still exceeded 400 Mcf/yr ($800/yr) while well maintained rod packings can generally reduce leakage to less than 100 Mcf/yr even on fully pressurized systems. Consequently this may be a useful method for reducing leakage but should not be substituted for good rod packing maintenance.

4.3 Packing Seal Maintenance

As noted in Figure 2, the packing seal leakage distribution measured at the ten sites showed considerable variation of leak rates. This variability may be due to site maintenance practices, packing seal type, age of packing, typical compressor activity usage, and other factors. Tables 5 and 6 present leak rates sorted by type of packing seal material. Table 5 contains information from the ten facilities measured during this study, while Table 6 contains information from forty-one private client sites. These private client sites were all part of the same gas company transmission system, and therefore may be influenced by company wide maintenance practices.

Table 5. Comparison of Rod Packing Leak Rates based on Rod Packing Material - PRCI/GRI/EPA Study [Sample Size = 220 Packing Seals]

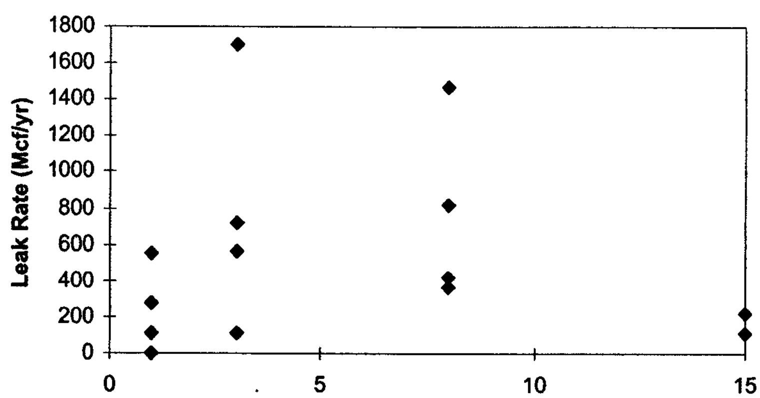
Packing Type	Bronze		Bronze/Teflon		Bronze/Steel	
Compressor Status	Running	Idle	Running	Idle	Running	Idle
No. of Packing Seals	136	8	46	18	12	N/A
Leak Rate (Mcf/yr) (± 95% Confidence Interval)	603 ± 148	126 ± 54	1633 ± 854	2194 ± 1271	593 ± 152	N/A

Table 6. Comparison of Rod Packing Leak Rates based on Rod Packing Material - Private Client Sites [Sample Size = 214 Packing Seals]

Packing Type	Bronze		Bronze/Teflon		Teflon	
Compressor Status	Running	Idle	Running	Idle	Running	Idle
No. of Packing Seals	49	91	18	32	14	10
Leak Rate (Mcf/Yr) (± 95% Confidence Interval)	800 ± 405	704 ± 237	840 ± 386	923 ± 313	225 ± 149	205 ± 76

In Table 5, bronze/Teflon packing leakage is considerably larger than the bronze material leak rate. However, in Table 6, both materials leak at a similar rate. Personnel at C. Lee Cook, a packing manufacturer, did not feel either type of packing was more appropriate to the typical pressures and temperatures observed at transmission compressor stations, and that both should perform at a similar level of success. Because the age of packings was usually not available, the influence of wear over time could not be included.

Figure 3. Packing Seal Age vs. Leak Rate - Site 6



It might be expected that packings with softer materials might have shorter longevity, and representatives from C. Lee Cook suggest that this is true (Harrison, 1997) unless additional lubrication is applied. However, there does not appear to be any manufacturer guidance on what typical packing lifetimes should be. Based on available data, Figure 3 shows the effect of age on leak rates across bronze rod packings at Site 6. Figure 3 indicates that there is a large variability in the leak rates of even relatively new packings. After only 1 month, four packing seals range between $5-$11OO/year of lost gas (at $2/Mcf). The largest packing leak rate occurred at a packing seal that had only been replaced 3 months prior to the measurement ($3,4OO/yr). Furthermore, there does not seem to be an observable trend in leak growth with packing age. The average packing seal leak rate after 1,3,8 and 15 months is 230, 770, 770, and 165 Mcf/yr, respectively. Since most sites do not seem to keep a detailed record of rod packing replacement schedules, further data regarding the age of rod packings is scarce.

To further investigate the factors that affect rod packing leak, an interview with a rod packing distributor (T.F. Hudgins, distributor of C. Lee Cook rod packing) was conducted (Parr, 1998). The following points summarize the recommendations of this distributor to reduce rod packing leakage:

1) Compressor Rods:
   a) Compressor rod misalignment (or rod run-out) should not exceed 0.004".
   b) Rod taper caused by uneven wear may also cause leakage, but there is no set guideline for the point at which this becomes a problem.
   c) Oversized rods will cause the arc of the packing to be off center and leakage will result.
   d) Rod finish should be between 8 to 12 µin rms. Smoother finishes (<8 µin) will not allow the packing material to imbed into the rod, while rougher finishes will cause excessive wear and tear on the packings. A new rod should be able to last for at least 15 years in a transmission pipeline application and can be expected to cost approximately $3000 to $3500.

2) Packing Cups and Case:
   a) The packing cup surfaces must be flat and smooth for the packing rings to seal to the face of the packing cup. Packing cups may require lapping to maintain this surface over time. One suggested test to determine if the packing cups require lapping is to hold a straightedge to the cup surface, shine a light from the opposite side, and look for light underneath the straightedge. It may be useful to stock a spare packing case at the site, at a cost of approximately $700.
   b) The packing case must allow the cups to float vertically and horizontally so that the packing can move up and down and side to side within the tolerances of rod misalignment.

3) Packing Materials
   a) The most common packing material is carbon filled Teflon used in combination with a bronze support backing ring. For higher temperature applications, bronze filled Teflon products conduct heat away better. For applications where hydrogen sulfide is present, cast iron is a better choice, than bronze, for the backing ring.
   b) Teflon packings in service at pressures greater than 200 psi should have a backing ring. Excessive heat can cause Teflon to extrude; excessive dirt will cause wear on the packing.
   c) Teflon packings can be lubricated or non-lubricated as the site chooses. In early carbon filled Teflon packing products, the carbon was leached out by lubrication, so that once lubrication was started it needed to be maintained, but this is no longer the case.
   d) Intermittent lubrication can cause materials that wear off the packing to accumulate and should be avoided.
   e) If hydrocarbon liquids are coming through in the gas stream, they may break down the lubricating oil and cause metal on metal wear if bronze packings are used, even though it may appear that adequate lubrication is present. If this scenario is likely, a Teflon packing may be a better choice to prevent this wear. Teflon packings may also reduce rod wear and will conform better to an uneven rod diameter.

4) The most common cause of leakage into the distance piece is the gasket on the crank end of the packing gland. This is usually a copper gasket, although some applications now use a Flexitallic™ gasket. If the gasket is over-tightened, it may deform and leak. Conversely, it may also leak if not tightened enough.

Many sites change rod packings without checking the packing case or the rod to determine if maintenance is needed. Based on these recommendations the data set was split into two identifiable groups: 1) sites that only changed rod packing without pulling the compressor rod, and 2) sites that changed rod packing by removing the rod and also inspecting the packing case. Of the ten reciprocating compressor sites surveyed, half changed the packing with the rod in place and half changed the packing by pulling the rod. This was not always a specific policy and all sites were familiar with both methods, but the sites were sorted by the predominant method used.

Table 7 summarizes leakage by packing seal replacement method. Data includes all packing seal measurements conducted at the ten sites, irrespective of the packing type, age or compressor type, age or usage factor. For running compressors, sites which changed rod packings with the rod in place had over twice the average leakage per rod packing as did the sites which conducted the more lengthy maintenance procedure of pulling the rod to change the packing. For idle compressors, the sites which changed rod packings without removing the rod had almost four times the average leak rate of sites where rods were removed, although the sample size for these sites is smaller and the results more uncertain.

Table 7. Rod Packing Leak Characteristics by Replacement Method - PRCI/GRI/EPA data

	Change Packing with Rod in Place	Change Packing with Rod Removed
Emission Factor' = Running Compressor	1,320 $\pm$ 530 Mcf/yr/seal (Sample Size = 76)	515 $\pm$ 140 Mcf/yr/seal (Sample Size = 98)
Emission Factor' = Idle Compressor	1,890 $\pm$ 2,390 Mcf/vr/seal (Sample Size = 22)	490 $\pm$ 275 Mcf/yr/seal (Sample Size = 24)
Percentage of Total Leaks < 100 Mcf/yr	17%	83%
Percentage of Total Leaks > I000 Mcf/yr	70%	30%

'Emission factors with associated 95% confidence levels.

Of the 220 packing seals measured during this study approximately 25% of the rod packings had a leak rate of less than 100 Mcf/yr. Hence, this rate of leakage appears to be an achievable goal. As shown in Table 7, of the rod packings surveyed during this project with leak rates of less than 100 Mcf/yr, 83% of these were at sites which pulled the rod to change packing, and only 17% were at sites that changed the packing with the rod in place. Conversely, larger leaks were more likely to be present on rod packings at the sites which change rod packings with the rod in place. 70% of the leaks larger than 1000 Mcf/yr occurred at these sites, while only 30% of the leaks greater than 1000 Mcf/yr occurred at sites which changed packing by removing the compressor rod.

Table 8 details results observed at private client site 4. The facility is currently in the midst of a thorough compressor packing seal maintenance program, and so provides a case study on the merits of different packing seal replacement strategies.

Table 8. Rod Packing Leak Characteristics by Replacement Method - Private Client Site 4

	Change Packing with Rod in Place	Change Packing with Rod Removed
Emission Factor' = Running Compressor	530 $\pm$ 370 Mcf/yr/seal	120 $\pm$ 85 Mcf/yr/seal
# of Packing Seals =	21	18

'Emission factors with associated 95% confidence levels.

As seen in Table 8 there is a marked difference between leakage from packing seals that have undergone thorough maintenance during replacement and those that have not. The average leakage from the packing seals for those compressors where the rod was removed was 120 Mcf/yr, while the average leakage from the packing seals that had been replaced with the rod in place was 525 Mcf/yr, nearly 4.5 times larger. These data indicate that if compressor packing seals are replaced by removing the compressor rod and the packing case, rod finish, rod level, and lubrication efficiency are checked, then packing seal leakage of approximately 100 Mcf/yr/seal is an achievable goal.

To confirm the effectiveness of this approach, a private client site with significant packing seal leakage was surveyed before and after maintenance was conducted based on the recommendations of T.F. Hudgins and using materials supplied by T.F. Hudgins but installed by site personnel. Table 9 presents the results of this work.

Table 9. Comparison of Packing Seal Leak Rates Before and After Total Maintenance

Compressor	Before Repair		After Repair	
	Total Leak Rate (Mcf/yr)'	Leak Rate/Seal (Mcf/yr)'	Total Leak Rate (Mcf/yr)'	Leak Rate/Seal (Mcf/yr)'
Compressor 1 - Running [4 Packing Seals]	8,300	2,075	460	115
Compressor 2 - Running [4 Packing Seals]	4,080	1,020	420	105

'Cost of gas = $2/Mcf

As Table 9 illustrates, a thorough approach to packing maintenance significantly reduced leakage at this site. Consequently, it appears that the recommendations by T.F. Hudgins may be a key tool in minimizing rod packing leakage and achieving leak rates of approximately 100 Mcf/yr.

4.4 Packing Seal Vent Monitoring

As Figure 1 illustrates, packing leakage can vary considerably even at sites that conduct uniform maintenance programs for all compressors. The best method of determining when maintenance is needed may be to institute routine monitoring of rod packings so that rod packings may be replaced when leakage reaches a given threshold based on either environmental, safety, or economic reasons.

Many sites have started to conduct such monitoring, but with differing approaches and results. Table 10 summarizes the packing seal monitoring currently being undertaken at several sites in this study, as well as at private client sites.

Table 10. Summary of Packing Monitoring Techniques at Various Sites

Site No.	Instrument Type	Packing Cup Monitoring	Distance Piece Monitoring	Packing Replacement Criteria	Comments
Site 2	Dry Gas Meter	Yes	No	> 0.6 cfm	No Distance Piece Vent Monitoring
Site 5	Dry Gas Meter	Yes	No	N/A	No Distance Piece Vent Monitoring - Distance piece leakage accounted for 83% of the total packing seal leakage.
Site 8	Dwyer Rotameter (O-200 cfh)	Yes	Yes	N/A	Rotameter creates back pressure on system, especially for large leaks--could lead to gas leaking past the wiper packing into the crankcase. Leak rates > 3.3 cfm are off the rotameter scale and cannot be quantified
Site 9	DwyerRotameter (O-200 cfh)	Yes	Yes	N/A	Same as Site 8
Private Client 4	Dwyer Magnehelic Pressure Gauge (O-50 in. H_2O)	Yes	No	> 40 in. H_2O	No Distance Piece Vent Monitoring--Distance piece leakage accounted for 30% of the total packing seal leakage.
Private Client 7	Dwyer Rotameter (O-100 cfh)	Yes	No	N/A	No Distance Piece Vent Monitoring--Distance piece leakage accounted for 25% of the total packing seal leakage. Leak rates > 1.7 cfm are off the rotameter scale and cannot be quantified.

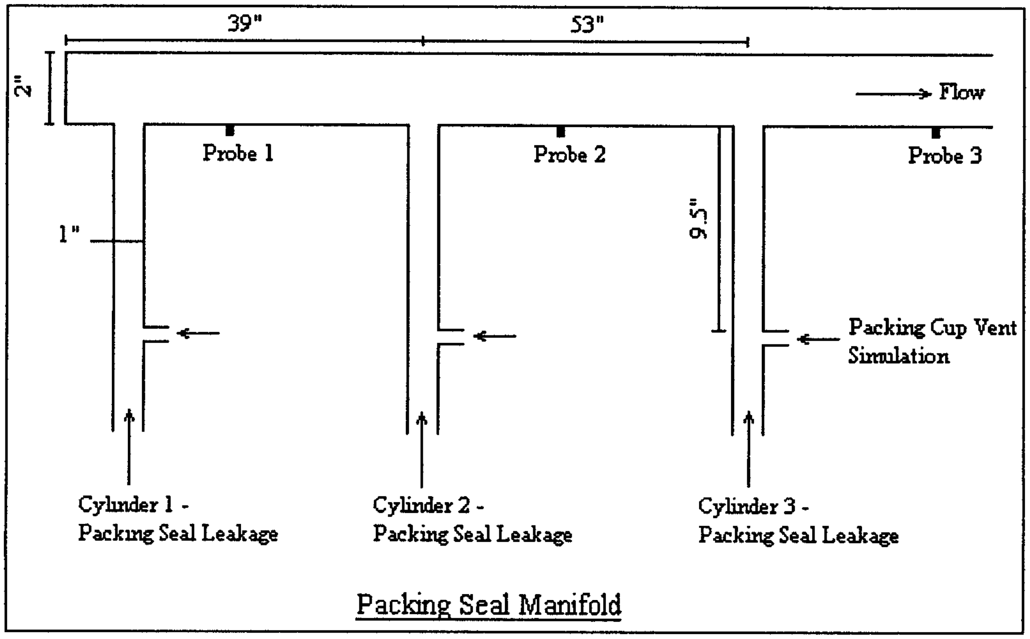
Most of the sites listed in Table 10 do not measure distance piece leakage. This can affect the threshold limit at which packing seal replacement decisions are made, since distance piece leakage on average is 30% of the total seal leakage. In some instances, distance piece leakage has far exceeded packing cup leakage. At one private client site leakage into the distance piece was approximately 86 cfm, while leakage from the packing cup vent totaled only 2.5 cfm. Consequently, the importance of measuring distance piece leakage should not be underestimated.

At Sites 8 and 9, rotameters were used to measure both the packing cup and distance piece leakage. Because the packing cup was vented into the distance piece, this method measures both leak pathways. However, the rotameter creates a back pressure on the distance piece vent which may present a safety hazard if leakage were to migrate into the crankcase.

Since a technique is clearly needed that is intrinsically safe, does not exert any pressure within the distance piece, and provides consistent, quick and accurate measurements, Indaco has tested the use of an intrinsically safe hot-wire anemometer probe to make these vent measurements. The anemometer probe would be used to determine the velocity in the packing cup/distance piece vent piping, and the flow rate calculated by multiplying the velocity with the pipe cross-sectional area. A correction factor may be needed to calibrate for vent characteristics. The hot-wire anemometer must be re-calibrated to account for the differences in heat transfer characteristics of air verses natural gas.

A vent manifold system was constructed using PVC, to simulate a three compressor cylinder reciprocating engine. Figure 4 details the test manifold constructed in the Indaco laboratory. To accommodate safety concerns, air was used as the test gas. Since the kinematic viscosity of both air and methane is approximately 0.16 and 0.14 cm^2/s, respectively, it was assumed that for the purposes of this experiment, air would simulate methane adequately.

Figure 4. Test Manifold for Monitoring Rod Packing Leakage with Hot Wire Anemometer



Based on standard velocity flow profiles, the centerline velocity is likely to overestimate average velocity, with the extent of this overestimation depending on whether the flow regime is turbulent or laminar. PVC piping was used, as opposed to steel (which forms the standard construction material for vent piping at most compressor facilities), due to the ease with which it could be manipulated for construction purposes. However, its roughness coefficient is close to that of a smooth pipe. Measurements conducted during this experiment would likely occur when the flow regime is in the transition zone. Since the boundary layer might be significant, there is likely to be some difference between the centerline and average velocity of flow within the pipe.

Compressed air was released into the manifold via a regulator and metered through a rotameter (Omega Engineering). Flow was directed into the three 1" vertical pipes (Figure 4), which were setup to mimic the flow patterns produced by three compressor cylinder seals leaking into the manifold. Ports (1/4 inch) were inserted into the 2" horizontal PVC section at different distances from each vertical riser. The hot wire anemometer was inserted into the ports to measure centerline flow velocities. Temperature and pressure were recorded concurrently with each measurement.

Several experiments were conducted to assess the reproducibility of the anemometer measurements under different leakage scenarios. The flows were varied into each of the three inlets to determine if the leakage from one rod packing might influence the measurement of leakage from a rod packing either upstream or downstream. Furthermore, in order to simulate the impact of separate packing cup tubing vents placed in the vertical pipe, air was metered into additional ports set within the vertical piping. It is believed that flow created from these packing cup tubing vents, which are common at many sites, might cause the most flow disruption and prevent an accurate measurement.

The optimum location for the anemometer port measurement appears to be in the horizontal header manifold. This would allow sufficient distance for the disruptions, created from the additional flow coming out of the separate packing cup vents, to smooth out. Port distances of 18 in, 25.5 in, and 36 in from where the vertical pipes connect with the horizontal header were tested. For this configuration, leakage from Cylinder No. 1 is directly measured by Probe No. 1, but leakage from cylinders vented to the manifold down stream of Cylinder No. 1 must be determined by difference. Therefore leakage from Cylinder No. 2 is equal to the leakage measured at Probe No. 2 minus the leakage measured at Probe No. 1. Similarly, leakage from Cylinder No. 3 is equal to the leakage measured at Probe No. 3 minus the leakage measured at Probe No. 2.

Flow rates calculated using the centerline velocity and the cross sectional area overestimated the actual flow rate by 30%, which is almost certainly due to centerline velocity overestimating average velocity. However, this factor was consistent throughout the different ranges of flow rates (0.8 to 24 scfm) and flow configurations. Once this factor was accounted for, the average variation between the anemometer calculations and the actual flow rates were less than 5%. When flow from a source had to be determined by the difference in measurement between two probes, this uncertainty increased, but remained less than 10%.

From these preliminary experiments the use of hot wire anemometer probes to monitor rod packing leakage appears to be feasible. However, it is not known if the ratio between centerline and average velocity will vary significantly between the laboratory manifold and actual compressor vents. Additionally, not all sites have a vent configuration that will allow this technique, although at least 80% of the sites we have surveyed during this and other programs appear to be good candidates. Valves to isolate oil drain systems from the distance piece temporarily during measurement would also need to be installed. If mitigation of rod packing leakage becomes a priority to the natural gas transmission industry, then field testing of this procedure should be considered.

Other approaches to mitigate compressor packing seal leakage are being developed. A&A Environmental Seals (Houston, Texas) have developed a system that captures gas leaking from rod packings for use as fuel gas. This system has not yet been tested on compressors at natural gas transmission stations. Tests are currently anticipated to begin in the winter of 1999 as part of the EPA Environmental Technology Verification Program for greenhouse gas technology. Potential benefits of this type of system would be the reduction of gas loss from rod packings to essentially zero and the reduction of rod packing maintenance costs, since theoretically the rod packings would only be worked on during major overhauls and would not need to be replaced routinely.

5.0 Summary and Conclusions

This report presents results of rod packing leakage measurements made during a program to determine cost effective methods of reducing leak rates at compressor stations sponsored by PRC International (PRCI), Gas Research Institute (GRI), and the Environmental Protection Agency (EPA). These leak rates have been made at 220 rod packings at ten sites during this work. The average leak rate per rod packing was 870 Mcf/yr for running compressors and 1270 Mcf/yr for idle compressors. The average total leak rate from rod packings was 20,400 Mcf/yr per station, equivalent to $40,80O/yr at $2/Mcf.

The distribution of leak sizes is critical to developing a cost effective strategy for mitigating this leakage. Of the 174 seals measured on running compressors, the largest 10% of these leaks accounted for 50% of the total leakage while the largest 20% accounted for 70% of the total. Compressor packing seal leakage occurs through both the packing cup and distance piece vents. The importance of leakage from the distance piece vent should not be underestimated, since it typically accounts for 30% of the total packing seal leak rate. At 10% of the sites that Indaco has surveyed for this and other programs, leakage into the distance piece has exceeded 20 cfm (10,000 Mcf/yr) on at least one compressor cylinder.

Leaving compressors at fuel gas pressure as opposed to full pressure when they are idle significantly reduced rod packing leakage. The average reduction per packing seal at the two sites assessed was 600 and 1200 Mcf/yr, respectively. However, leakage remained above 400 Mcf/yr/packing, so this technique should not be used in place of good rod packing maintenance.

There are several potential factors affecting rod packing leak rates, such as packing seal material, packing seal age, compressor usage, and packing maintenance practices. Of the 220 packing seals measured, nearly 25% had leak rates less than 100 Mcf/yr, indicating that this rate of leakage is an achievable goal. Information supplied by a packing seal distributor indicated that packing seal maintenance practices may be the primary factor in packing seal leakage. For packings replaced by removing the compressor rod and checking the packing case, lubrication, and rod finish as opposed to just changing the packing with the rod in place, the average packing leak rate was at least two times lower. Furthermore, 83% of rod packings with leak rates less than 100 Mcf/yr had undergone the more thorough maintenance. Similarly, 70% of the rod packings with leak rates larger than 1000 Mcf/yr occurred at compressors where the packings were replaced with the rod in place.

Measurements were conducted at a private client facility before and after it had undergone a thorough packing maintenance including rod replacement with correct finish, packing replacement, and packing case inspection. Leakage was reduced from over 1000 Mcf/yr/packing to approximately 100 Mcf/yr/packing. It appears that a thorough approach to rod packing maintenance may be the key tool in minimizing packing seal emissions.

An accurate, quick, and safe monitoring system is required for cost effective rod packing maintenance. Laboratory tests using a hot-wire anemometer to measure flow velocities via ports in a manifold system were conducted. The average variation between measured and actual flow rates was within 10% for all flow rates and flow configurations, indicating this may be a useful strategy for vent system monitoring.

6.0 References

American Petroleum Institute, 1996. Calculation Workbook for Oil and Gas Production Equipment Fugitive Emissions. API Publication 4638, Washington, DC.

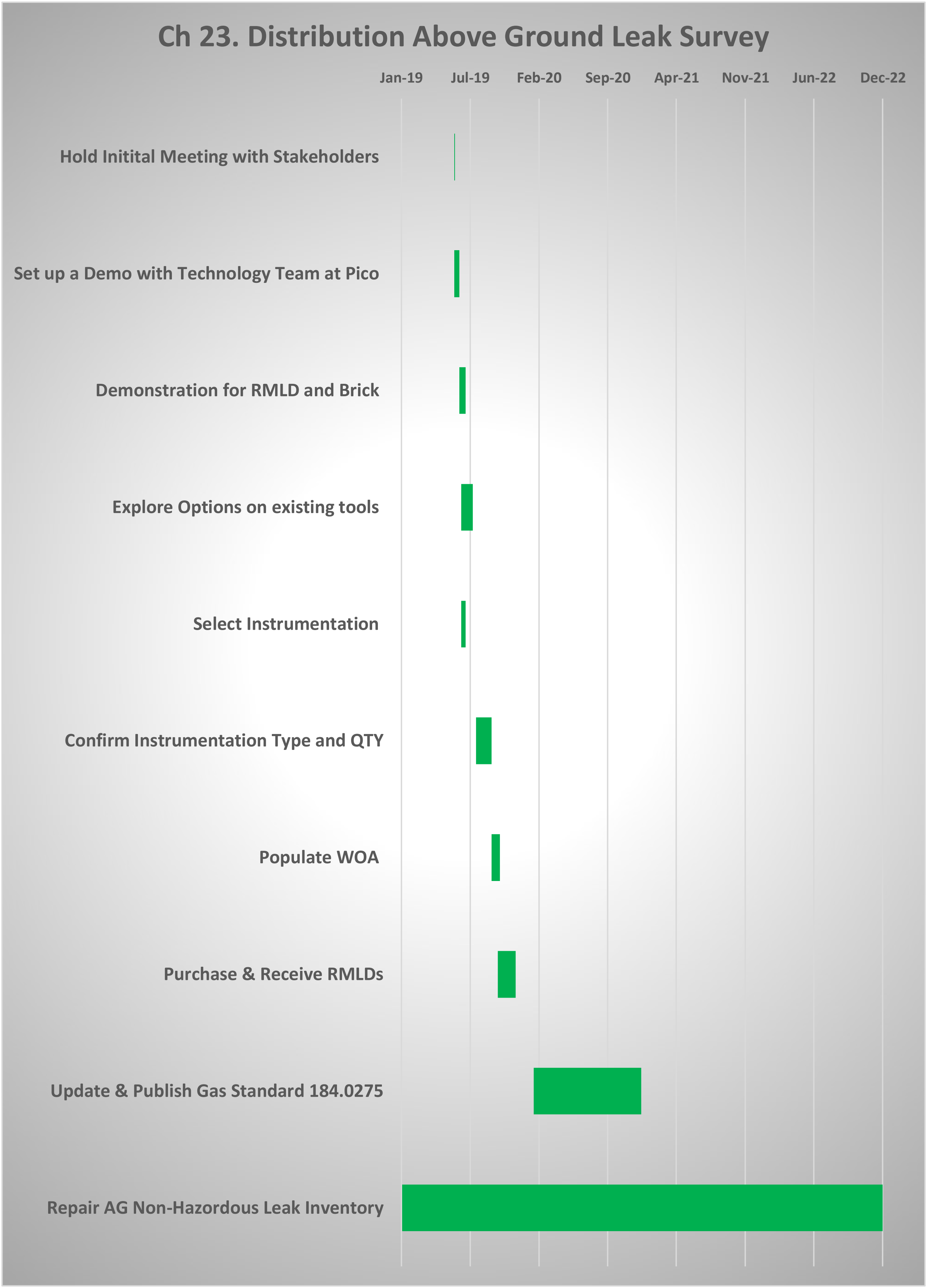
CMA, 1989. Improving Air Quality: Guidance for Estimating Fugitive Emissions from Equipment. Chemical Manufacturer's Association, Washington, DC 20037.

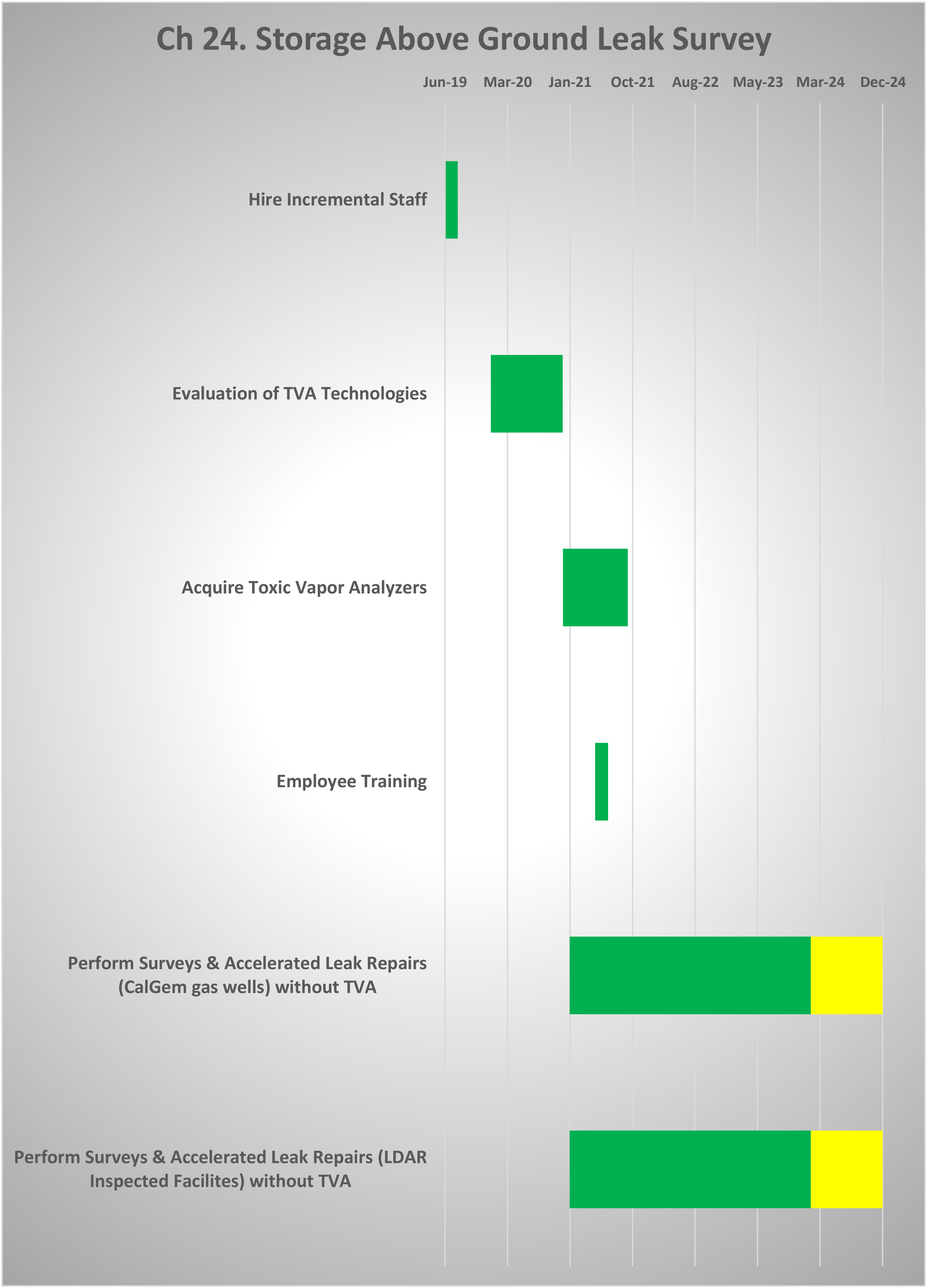
Harrison, M., K. Ferry, C. Loughran, 1997. Documentation of Existing Compressor Rod Packing Technology and Emissions, Gas Research Institute, Chicago, IL.

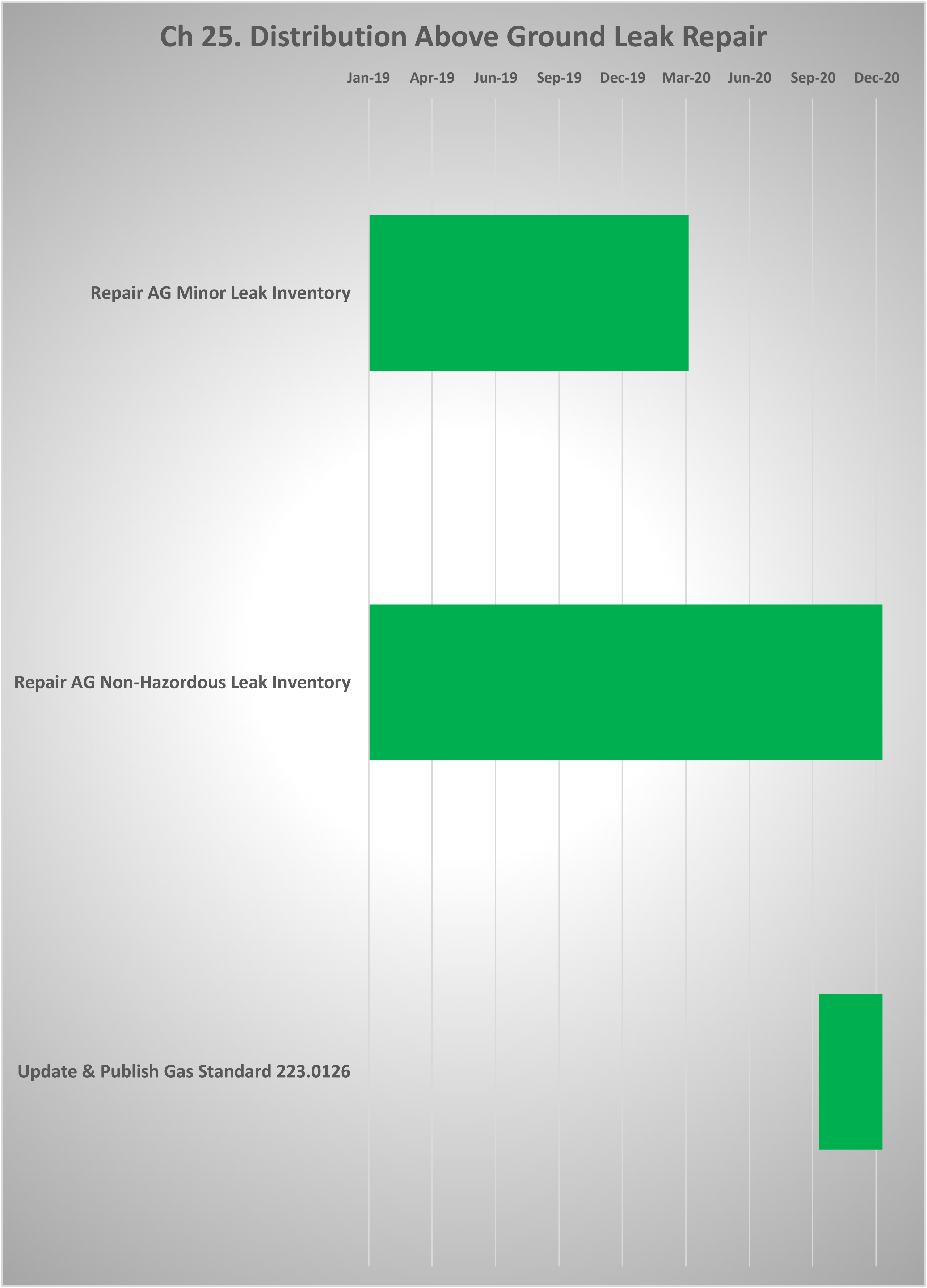
Howard, T., R. Siverson, A. Wenzlick, and P. Cooper, 1995a. Leak rates measurements at natural gas compressor stations. GRI-94/0257.37, Gas Research Institute, Chicago, IL.

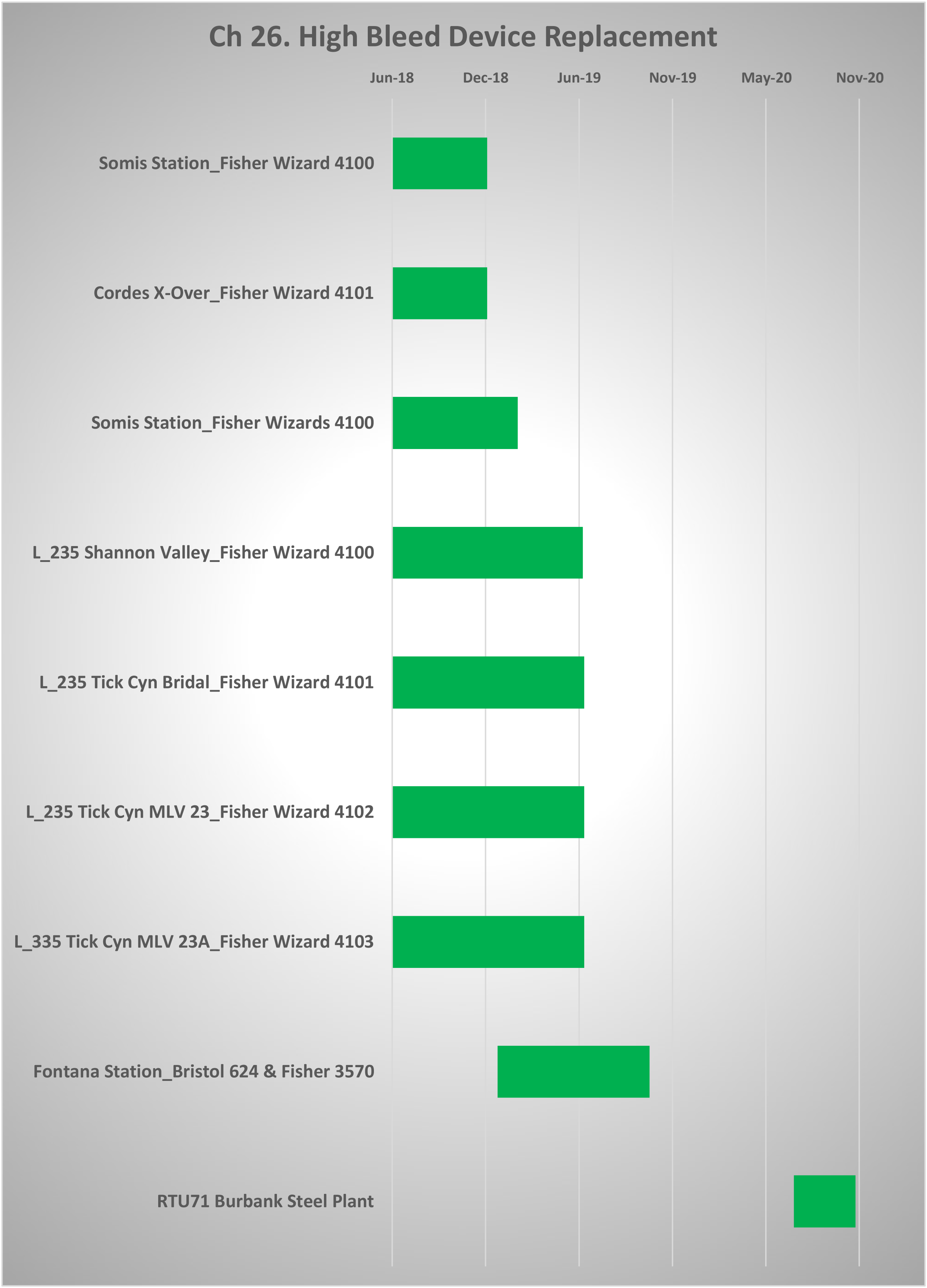
Howard, T., R. Siverson, A. Wenzlick, and P. Cooper, 1995b. A high flow rate sampling system for measuring leak rates at natural gas facilities. GRI-94/0257.38, Gas Research Institute, Chicago, IL.


Ch 22. Vapor Collections System
Jan-19
Jul-19
Feb-20
Sep-20
Apr-21
Nov-21
Jun-22
Dec-22
Submit WOA & Obtain an I/O number
Work with Gas Engineering to evaluate Full System Design
IFC Package and Approvals
Order & Receive Materials
Go Live Blythe
Blythe Project NOP & Close-out
Provide Final Cost for Blythe Project
Collect Emissions Data
Identify & Evaluate Cost per Emission Reduction
Submit Report on Findings


Ch 23. Distribution Above Ground Leak Survey
Jan-19
Jul-19
Feb-20
Sep-20
Apr-21
Nov-21
Jun-22
Dec-22
Hold Initital Meeting with Stakeholders
Set up a Demo with Technology Team at Pico
Demonstration for RMLD and Brick
Explore Options on existing tools
Select Instrumentation
Confirm Instrumentation Type and QTY
Populate WOA
Purchase & Receive RMLDs
Update & Publish Gas Standard 184.0275
Repair AG Non-Hazordous Leak Inventory


Ch 24. Storage Above Ground Leak Survey
Jun-19
Mar-20
Jan-21
Oct-21
Aug-22
May-23
Mar-24
Dec-24
Hire Incremental Staff
Evaluation of TVA Technologies
Acquire Toxic Vapor Analyzers
Employee Training
Perform Surveys & Accelerated Leak Repairs (CalGem gas wells) without TVA
Perform Surveys & Accelerated Leak Repairs (LDAR Inspected Facilites) without TVA


Ch 25. Distribution Above Ground Leak Repair
Jan-19
Apr-19
Jun-19
Sep-19
Dec-19
Mar-20
Jun-20
Sep-20
Dec-20
Repair AG Minor Leak Inventory
Repair AG Non-Hazordous Leak Inventory
Update & Publish Gas Standard 223.0126

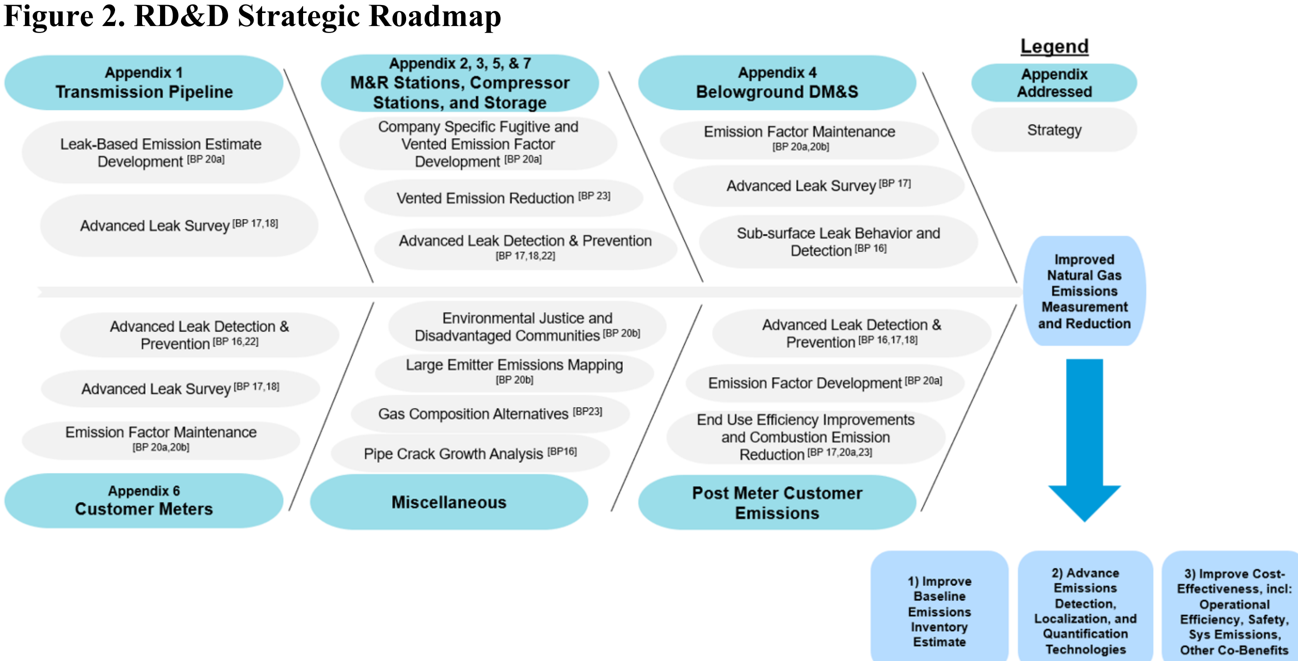

Ch 26. High Bleed Device Replacement
Jun-18
Dec-18
Jun-19
Nov-19
May-20
Nov-20
Somis Station_Fisher Wizard 4100
Cordes X-Over_Fisher Wizard 4101
Somis Station_Fisher Wizards 4100
L_235 Shannon Valley_Fisher Wizard 4100
L_235 Tick Cyn Bridal_Fisher Wizard 4101
L_235 Tick Cyn MLV 23_Fisher Wizard 4102
L_335 Tick Cyn MLV 23A_Fisher Wizard 4103
Fontana Station_Bristol 624 & Fisher 3570
RTU71 Burbank Steel Plant

2024 SB 1371 Compliance Plan
RD&D Summary

Best Practice Addressed	RD&D Project	Subject
16	16	Leak Detection and Prevention Algorithms
17, 20a	17	Evaluation of Instruments and Methods for Leak Detection, Quantification, Localization, and Speciation
18	18	Evaluation of Stationary Methane Detectors
20a, 20b	20a	Develop and Maintain Company-Specific EFs
22	22	Leak Prevention for Threaded Connections
23	23	Evaluation of Technologies to Mitigate Gas Blowdowns & Vented Emissions

Figure 2 provides a strategic roadmap for developing solutions (to the maximum extent cost-effectively feasible) for preventing or mitigating system emissions of natural gas for each section of Appendix 8 in the Annual Reporting requirements pursuant to R.15-01-008. The Miscellaneous research branch addresses Best Practices which are not directly reflected in annual emissions report, such as BP 20b Geographic Tracking, and gas composition alternatives which are integral to the underlying calculations within Appendix 8. The Post Meter Customer Emissions research branch addresses customer side methane emissions from leaks and incomplete combustion which, while not currently included in annual emissions report, do contribute to greenhouse gas emissions into the atmosphere. Based on CPUC guidance, the goal of the research proposed within this Compliance Plan aims to improve estimates of system emissions and strategically reduce system emissions while considering operational efficiency and cost effectiveness. Each section of this RD&D chapter is associated with the Best Practices provided in the strategy of the RD&D Strategic Roadmap which is focused on improving the cost effectiveness of these leak abatement Best Practices. These sections include estimates of the emission abatement potential and associated implementation cost.

Figure 2. RD&D Strategic Roadmap



2024 SB 1371 Compliance Plan
RD&D Summary #16
Leak Detection and Prevention Algorithms

Part 1. Best Practice Addressed in this Chapter

This section addresses the following Best Practice(s):

Best Practice 16: Special Leak Surveys
Utilities shall conduct special leak surveys, possibly at a more frequent interval than required by G.O. 112-F (or its successors) or BP 15, for specific areas of their transmission and distribution pipeline systems with known risks for natural gas leakage. Special leak surveys may focus on specific pipeline materials known to be susceptible to leaks or other known pipeline integrity risks, such as geological conditions. Special leak surveys shall be coordinated with transmission and distribution integrity management programs (TIMP/DIMP) and other utility safety programs. Utilities shall file in their Compliance Plan proposed special leak surveys for known risks and proposed methodologies for identifying additional special leak surveys based on risk assessments (including predictive and/or historical trends analysis). As surveys are conducted over time, utilities shall report as part of their Compliance Plans, details about leakage trends. Predictive analysis may be defined differently for differing companies based on company size and trends.

Part 2. Name and Type of RD&D Objective or Program Pilot

Name: Leak Detection and Prevention Algorithms

Type of Objective(s) or Program Pilot:

- Improve understanding of underground methane concentration “background” and leak migration behavior and validate current practices for belowground methane concentration threshold(s), resulting in improved leak detection efficiency.
- Continue advancing the understanding of how leak flow rates evolve over time on various pipeline materials.

Part 3. RD&D Objectives

Study methane environment around below-ground pipelines and determine factors that contribute to leak development and migration. Understanding of these factors will be used to develop numerical models to predict gas behavior in the distribution environment. Additionally, this research may be used to determine the appropriate below-ground methane concentration threshold(s) that should trigger the creation of a leak record and investigation. This knowledge will assist in improving system leakage estimates and EFs and help to optimize leak survey intervals based on projected emission growth rates. This research area has potential pipeline safety, integrity, and reliability co-benefits. The table below shows the primary and secondary focus areas across Transmission, Distribution, and Storage that would benefit from this research.

2024 SB 1371 Compliance Plan
RD&D Summary #16
Leak Detection and Prevention Algorithms

Areas Targeted

Transmission			**Distribution**			**Storage**	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
f			F		f	f	

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v – Vented

Part 4. Current and Proposed Projects

Current Projects (2022 Compliance Plan):

1. Leak Prevention with Intelligent Image Processing (SCG-2021-004)
   Explore the prevention of leaks on aboveground assets by automatically recognizing conditions that lead to leaks using intelligent image processing, such as corrosion condition, facility damage, encroachment, and tampering.
   - Anticipated Project Close Out: Q3 of 2024.
2. System Emissions Using Mass Balance with Advanced Meter Technology Research Project (SCG-2018-006)
   Assess the feasibility of developing algorithms designed for early detection of distribution system leaks using a mass-balance approach and leveraging consumption data from the Advanced Meter (AM) network for a defined study area.
   - Anticipated Project Close Out: Q3 of 2024.
3. PE Leak Growth Rate from Slow Crack Growth Research Project (OTD 7.15.c)
   Evaluate how leaks evolve over time due to slow crack growth on polyethylene (PE) pipe to gain a better understanding of its contribution to methane emissions from PE pipelines.
   - Anticipated Project Close Out: Q4 of 2024.

New Proposed Projects:

1. Leak Prevention through Root Cause Analysis of Large Leaks in the Distribution Environment and integration with DIMP risk algorithms
   - Anticipated Start Date: Q1 of 2025.
   - Anticipated End Date: Q4 of 2026.
2. Evaluate Leak Detection Threshold(s) for Distribution Leak Survey by Material
   - Anticipated Start Date: Q3 of 2025.
   - Anticipated End Date: Q3 of 2026.
3. PE Leak Growth Rate from Slow Crack Growth (Phase II)
   - Anticipated Start Date: Q1 of 2025.
   - Anticipated End Date: Q2 of 2026.

2024 SB 1371 Compliance Plan
RD&D Summary #16
Leak Detection and Prevention Algorithms

Part 5. Expected Results

- Use acquired understanding to determine the appropriate below-ground methane concentration threshold(s) that should trigger creation of a leak record and investigation.
- Use acquired understanding to enable field technicians to determine if below-ground methane indications are due to a leak from the natural gas piping system.
- Increase understanding of the impact on methane emissions from the leak growth rate due to cracks in the Polyethylene (PE) pipeline.

Part 6. Estimated Emissions Impact

- This research category has an estimated emission abatement potential of 5%-10% of total system emissions. To meet a target cost effectiveness of $22/MCF, this would require a solution with an estimated implementation cost of $2.5 million.
- Knowledge of the below-ground methane threshold may reduce both false positives (recording a leak when there is no leak) and false negatives (not recording a leak when one exists), which would increase operational efficiency and result in overall shorter leak duration and emission reductions.
- Potential co-benefits associated with this research category include improvements in pipeline safety due to early leak detection and/or prevention. These co-benefits should be considered in future implementation cost effectiveness calculations.

Part 7. Data Collection and Analysis Plan

The RD&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:

a) Simulated Field Evaluation (Emissions Sources)
   - Evaluate each test matrix in a simulated field environment utilizing controlled natural gas releases.

b) Pilot Study
   - Collect methane concentration samples.
   - Perform follow-up leak investigations.
   - Evaluate various methane concentration thresholds for early leak detection and compare to current practices.

c) Statistically analyze collected below-ground methane concentrations and flow rate data.

2024 SB 1371 Compliance Plan
RD&D Summary #16
Leak Detection and Prevention Algorithms

Part 8. Expected Utility Total Cost

Incremental Cost Estimates (Provided in 2024 Dollars and Direct Costs)

SoCalGas

2025	2026
$384,864	$488,576

SDG&E

2025	2026
$38,063	$48,321

Rate-Recoverable Loaded Costs Submitted in Advice Letters (NGLAPBA One-Way Balancing Account)

Utility	Total Loaded Costs
SoCalGas	$1,169,472
SDG&E	$115,662

2024 SB 1371 Compliance Plan
RD&D Summary #17
Evaluation of Instruments and Methods for Leak Detection, Quantification, Localization, and Speciation

Part 1. Best Practice Addressed in this Chapter

This section addresses the following Best Practice(s):

Best Practice 17: Enhanced Methane Detection
Utilities shall utilize enhanced methane detection practices (e.g. mobile methane detection and/or aerial leak detection) including gas speciation technologies.

Best Practice 20a: Quantification
Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together, with CPUC and ARB staff, to come to an agreement on a similar methodology to improve emissions quantification of leaks to assist the demonstration of actual emission reductions.

Part 2. Name and Type of RD&D Objective or Program Pilot

Name: Evaluation of Instruments and Methods for Leak Detection, Quantification, Localization, and Speciation.

Type of Objective or Program Pilot:

- Improve efficiency and reduce cost of system operations.
- Reduce emissions and improve efficiencies by detecting, differentiating, and rapidly responding to large leaks.
- Pilot studies to validate actual costs and leak detection, localization, and system capabilities of next generation.

Part 3. RD&D Objective

Develop and demonstrate instruments and/or methods to improve the efficiency and output of leak detection, localization, and quantification processes. Evaluate the performance and features of new instruments and/or methods and perform comparative analysis to existing methods for leak detection, source localization, and speciation of natural gas to estimate potential incremental benefits. The tables below show the primary and secondary focus areas across Transmission, Distribution, Storage, and Post-Meter emissions that would benefit from this research.

2024 SB 1371 Compliance Plan
RD&D Summary #17
Evaluation of Instruments and Methods for Leak Detection, Quantification, Localization, and Speciation

Areas Targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
F,v	F,v	F,v	F,v	F,v	F,v	F,v	F,v

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v – Vented

Post-Meter (Customer Emissions)			
Yard Line	House Line	Incomplete Combustion	Vented Emissions
F	F	V	V

Part 4. Current and Proposed Projects

Current Projects (2022 Compliance Plan):

1. Integrate Mobile Methane Mapping w/ Mobile Leak Survey Research Project (SCG-2018-005)
   Evaluate possibility of integrating GIS and wind (speed and direction) data into traditional mobile leak survey applications where mobile leak survey is conducted directly over the pipeline right-of-way. Increase the leak detection capabilities of mobile methane mapping by integrating multiple methane detection systems to increase lower detection limit and minimize false-positive indications.
   - Project Completed: Q1 of 2022.
2. Evaluate Mobile Mapping Services (SCG-2021-009)
   Evaluate algorithms to identify which mobile methane measurements have a high likelihood of being associated with natural gas emissions over multiple drives.
   - Project Completed: Q4 of 2022.
3. Aerial Methane Mapping (SCG-2019-012)
   Pilot studies were conducted in several distribution service areas and conditions to measure system capability for methane emissions detection, localization and quantification. As result of this study, additional insight was gained as to the varied sources of methane emissions in the distribution operating environment.
   - Project Completed: Q3 of 2023.
4. First Pass Leak Detection Optimization (NYSEARCH T-784)
   Develop and evaluate walking survey approach using various instruments to enhance walking leak survey detection and localization of leaks.
   - Anticipated Project Close Out: Q2 of 2024.

2024 SB 1371 Compliance Plan
RD&D Summary #17
Evaluation of Instruments and Methods for Leak Detection, Quantification, Localization, and Speciation

5. BackPack & Handheld Methane Detection Tools (Sensor) & Systems Research Projects (a.k.a. Next Generation Walking Leak Survey) (SCG-2018-004)
   Evaluate and develop the use of portable ppb-detection capable instruments to enhance walking leak survey detection and localization of leaks.
   - Anticipated Project Close Out: Q3 of 2024.
6. Evaluate New Mobile Leak Detection, Localization, and Speciation Technologies (SCG-2022-007)
   Evaluate new advanced mobile leak detection systems and compare with existing approved mobile technologies.
   - Anticipated Project Close Out: Q4 of 2024.
7. Aerial (sUAS) Leak Detection Research Projects (SCG-2016-001)
   Progressive development of drone and sensor instrument by respective manufacturers.
   - Anticipated Project Close Out: Q4 of 2024.
8. Aerial Leak Detection - Satellite (SCG-2021-005)
   Evaluate and demonstrate the capabilities of satellite technologies for leak detection and localization in transmission and distribution applications using satellite systems, and to evaluate the cost effectiveness in reducing emissions.
   - Anticipated Project Close Out: Q4 of 2024.

Lessons Learned:

- Handheld ppb-detection capable instruments have not yet shown significant advantages over traditional handheld ppm-detection instruments in leak detection capabilities. The next generation of this technology would attempt to improve detection capabilities (e.g., true positive rates), leak localization, quantification efficiency, and source attribution, to increase cost effectiveness.
- Mobile ppb-detection capable instruments have claimed improved detection capabilities over mobile ppm-detection instruments in some operating environments. However, the hardware technology alone does not produce adequate true positive detection rates. Further innovations (e.g., filtering algorithms) are needed. The next generation of this technology would attempt to improve detection capabilities (e.g., true positive rates), leak localization, quantification efficiency, and source attribution, which are expected to improve cost effectiveness.
- Technologies deployed on aerial platforms continue to show promising results during the 2022 Compliance Period. Further research efforts will attempt to improve probabilities of detection (detection at lower flow rates) and source attribution, which may increase cost effectiveness. The inclusion of program co-benefits, such as safety improvements associated with detection and repair of customer leaks, would further improve cost effectiveness.

2024 SB 1371 Compliance Plan
RD&D Summary #17
Evaluation of Instruments and Methods for Leak Detection, Quantification, Localization, and Speciation

- Aerial Methane Mapping (AMM) has been shown to be an effective incremental leak survey methodology (incremental to compliance walking leak survey). Unmanned aircraft technology platforms need to be developed for the next-generation advancement of the AMM program to improve the probabilities of detection at lower leak flow rates and overall cost effectiveness.
- Other aerial technologies (such as satellite-based methane detection and tethered balloons) continue to be evaluated as these methods mature over time from their current early-stage status, which is limited to leaks that exceed the size of typical fugitive emissions from the distribution environment.

New Proposed Projects:

1. Develop and pilot advanced handheld leak detection, localization, and speciation technologies.
    - Anticipated Start Date: Q2 of 2025.
    - Anticipated End Date: Q3 of 2026.
2. Develop and pilot next generation LiDAR sensors for aerial leak detection, localization, and speciation technologies.
    - Anticipated Start Date: Q1 of 2025.
    - Anticipated End Date: Q4 of 2026.
3. Develop and pilot augmentations for Advanced Meter algorithms to improve the cost-effectiveness and safety benefits of LiDAR based technologies.
    - Anticipated Start Date: Q1 of 2025.
    - Anticipated End Date: Q4 of 2026.

Part 5. Expected Results

- Identify more accurate, precise, reliable, and/or cost-effective instruments and methods for leak detection, localization, and speciation processes.
- Use acquired knowledge to improve the efficiency of current manned aircraft operations.
- Use acquired knowledge to determine the usefulness of each application to both small scale and large-scale needs in practical applications of gas utility routine or emergency operations.
- Use acquired knowledge to determine the feasibility of applying these technologies to both routine operations in difficult-to-access locations or for emergency response.
- Develop capability for quick response to assess emissions from the natural gas system during routine operational requirements or emergency response.

Part 6. Emissions Impact

- This research category has an estimated emission abatement potential of 10%-30% of the total natural gas emissions. To meet a target cost effectiveness of $22/MCF, this would require a solution with an estimated implementation cost of $7.5 million.

- Emission reductions could be realized by improving detection, leak localization, and quantification efficiency. Leaks detected and repaired earlier in the lifecycle would result in a reduction of emissions, while leak detection and localization efficiency would reduce operational costs.
- Potential co-benefits associated with this research include improvements in pipeline safety associated with early leak detection and/or prevention. These co-benefits should be considered in future implementation cost effectiveness calculations.

Part 7. Data Collection and Analysis Plan

The RD&D approach to meet the objective will involve a series of planned evaluations that can include one or more of the following:

a) Manufacturer Demonstration
   - Perform manufacturer demonstration to identify potential capabilities that could be leveraged for leak detection, speciation, and localization.

b) Laboratory Evaluation
   - Perform laboratory evaluation to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet research objectives (Go/No-Go Decision).
   - Leverage results of laboratory data to guide simulated field-testing plan.

c) Evaluate Cost of Implementation
   - Estimate cost to conduct simulated field evaluation.
   - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).

d) Simulated Field Evaluation (Controlled Environment)
   - Perform simulated field evaluation to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet research objectives (Go/No-Go Decision).
   - Leverage results of simulated field evaluation data to guide pilot study plan.
   - Evaluate integration of instrument data into Enterprise Data Management Systems and business process workflows.
   - Re-evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).

e) Pilot Study
   - Verify capability for intended applications, and that the technology, practices and/or procedures can meet research objectives (Go/No-Go Decision).

2024 SB 1371 Compliance Plan
RD&D Summary #17
Evaluation of Instruments and Methods for Leak Detection, Quantification, Localization, and Speciation

Part 8. Expected Utility Total Cost

Incremental Cost Estimates (Provided in 2024 Dollars and Direct Costs)

SoCalGas

2025	2026
$1,536,908	$1,575,331

SDG&E

2025	2026
$152,002	$155,802

Rate-Recoverable Loaded Costs Submitted in Advice Letters (NGLAPBA, One-Way Balancing Account)

Utility	Total Loaded Costs
SoCalGas	$4,091,724
SDG&E	$404,676

2024 SB 1371 Compliance Plan
RD&D Summary #18
Evaluation of Stationary Methane Detectors

Part 1. Best Practice Addressed in this Chapter

This project addresses the following Best Practice(s):

Best Practice 18: Stationary Methane Detectors for Early Detection of Leaks
Utilities shall utilize Stationary Methane Detectors for early detection of leaks. Locations include: Compressor Stations, Terminals, Gas Storage Facilities, City Gates, and Metering & Regulating (M&R) Stations (M&R above ground and pressures above 300 psig only). Methane detector technology should be capable of transferring leak data to a central database, if appropriate for location.

Part 2. Name and Type of RD&D Objective or Program Pilot

Name: Evaluation of Stationary Methane Detectors

Type of Objective or Program Pilot:

- Reduce emissions through earlier leak detection and repair.
- Develop new stationary leak detection technologies or deployment strategies.
- Perform pilot studies based on results of instrument evaluations and evaluate implementation costs and emission reductions.

Part 3. RD&D Objective

Develop and/or evaluate stationary methane sensors for early detection of leaks. The table below shows the primary and secondary focus areas across Transmission, Distribution, and Storage emissions that would benefit from this research.

Areas Targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
	F,V	f,v		f,v	F,V	F,V	f,v

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v – Vented

Part 4. Current and Proposed Projects

Current Projects (2022 Compliance Plan):

1. Develop Remote Sensing and Leak Detection Platform with Multiple Sensors (OTD 7.20.a)
   Improved and deployed additional instances of a defensive pipeline right-of-way (ROW) monitoring system based on stationary sensors mounted on and near the

pipeline. Sensor data from multiple locations along the pipe was wirelessly forwarded to a central location for processing. Analytics at the central location correlated data from multiple sensors to rapidly alert operators to events occurring in the ROW. One prototype system was deployed.
   - Project Completed: Q4 of 2023.
2. Evaluate New and/or Prototype Stationary Methane Sensor Technologies
   Compare sensors with manufacturer's specifications, measurement accuracy, efficiency, and repeatability as compared to similar sensors.
   - Anticipated Project Close Out: Q1 of 2024.
3. Stationary Methane Detector for Facility Applications (SCG-2021-003)
   Evaluate application of residential methane detectors (RMDs) that detect at 10% Lower Explosive Limit (LEL) to indoor and difficult to reach meter locations. Detectors to be evaluated during one-year pilot field study.
   - Anticipated Project Close Out: Q4 of 2024.
4. Stationary Methane Sensor Evaluation for Transmission M&R (SCG-2021-010)
   Evaluate additional stationary methane sensor technologies and perform a pilot study at transmission M&R stations.
   - Anticipated Project Close Out: Q4 of 2024.

Lessons Learned:

- Stationary methane detection instruments showed reasonable methane detection capabilities during previous Compliance Periods.
- For distribution and transmission M&R facilities, stationary methane sensors did not produce a cost-effective mitigation approach to the relatively low fugitive emissions present at these facilities.
- Research related to detecting vented emission events from actuators at transmission M&R facilities demonstrated that understanding temporal release data is critical to properly estimating emissions.

New Proposed Projects:

1. Evaluate Potential Cost-Effective Applications for New Stationary Methane Sensors.
   - Anticipated Start Date: Q2 of 2025.
   - Anticipated End Date: Q2 of 2026.

Part 5. Expected Results

- Identify viable cost-effective applications for stationary sensors to accurately detect and/or quantify emissions from leaks and actuators.
- Accurately assess the performance of stationary sensors that are fit-for-purpose regarding field deployment to provide actionable data leading to quicker leak detection,

localization, and repair.
- Identify opportunities to detect and mitigate abnormalities in vented emissions associated system actuators

Part 6. Emissions Impact

- Studies quantifying emissions were conducted during the previous Compliance Periods. As a result of this research, the estimated mitigation potential from this best practice for M&R and storage, from both leak mitigation and more accurate accounting of emissions, is approximately 10% of total emissions. To meet a target cost effectiveness of $22/MCF, this would require a solution with an estimated implementation cost of $2.5 million.
- Potential co-benefits associated with this research include improvements in system reliability by leveraging automation of data gathering and analytics.

Part 7. Data Collection and Analysis Plan

The RD&D approach to meet the objective will involve a series of planned evaluations that can include one or more of the following:

a) Manufacturer Demonstration
    - Perform manufacturer demonstrations to identify potential capabilities that can be leveraged for leak detection, speciation, and localization.
b) Laboratory Evaluation
    - Perform laboratory evaluation to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet research objectives (Go/No-Go Decision).
    - Leverage results of laboratory data to guide simulated field-testing plan.
c) Evaluate Cost of Implementation
    - Estimate cost to conduct simulated field evaluation.
    - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
d) Simulated Field Evaluation (Controlled Environment)
    - Perform simulated field evaluation to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet research objectives (Go/No-Go Decision).
    - Leverage results of simulated field evaluation data to guide pilot study plan.
    - Evaluate integration of instrument data into EDMS and business process workflows.
    - Re-evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).
e) Pilot Study
    - Verify capability for intended applications, and that the technology, practices and/or procedures can meet research objectives (Go/No-Go Decision).
    - Re-evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).

2024 SB 1371 Compliance Plan
RD&D Summary #18
Evaluation of Stationary Methane Detectors

Part 8. Expected Utility Total Cost

Incremental Cost Estimates (Provided in 2024 Dollars and Direct Costs)

SoCalGas

2025	2026
$76,321	$78,228

SDG&E

2025	2026
$7,548	$7,737

Rate-Recoverable Loaded Costs Submitted in Advice Letters (NGLAPBA One-Way Balancing Account)

Utility	Total Loaded Costs
SoCalGas	$238,651
SDG&E	$23,603

2024 SB 1371 Compliance Plan
RD&D Summary #20a
Develop and Maintain Company-Specific Emission Factors

Part 1. Best Practice Addressed in this Chapter

This project addresses the following Best Practice(s):

Best Practice 20a: Quantification
Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together, with CPUC and ARB staff, to come to an agreement on a similar methodology to improve emissions quantification of leaks to assist the demonstration of actual emission reductions.

Best Practice 20b: Geographic Tracking
Utilities shall develop methodologies for improved geographic tracking and evaluation of leaks from the gas systems. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve geographic evaluation and tracking of leaks to assist demonstrations of actual emission reductions. Leak detection technology should be capable of transferring leak data to a central database in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

Part 2. Name and Type of RD&D Objective or Program Pilot

Name: Develop and Maintain Company-Specific Emission Factors.

Type of Objective of Program Pilot:

- Company-Specific Emission Factors (EFs) would result in more accurate quantification of emissions than current methods.
- Facilitate cost-effective reduction of emissions through defining leak-based EFs and reduction in time to repair and increase frequency of leak survey.

Part 3. RD&D Objective

Develop Company-Specific EFs based on SoCalGas and SDG&E data. These EFs would replace current “facility-based” or “population-based” EFs. The tables below show the primary and secondary focus areas across Transmission, Distribution, Storage, and Post-Meter emissions that would benefit from this research.

2024 SB 1371 Compliance Plan
RD&D Summary #20a
Develop and Maintain Company-Specific Emission Factors

Areas Targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
F,V	F,V	F,V	F		F	F,V	F,V

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v – Vented

Post-Meter (Customer Emissions)			
Yard Line	House Line	Incomplete Combustion	Vented Emissions
F	F	V	V

Part 4. Current and Proposed Projects

Current Projects (2022 Compliance Plan):

1. Develop Company-Specific EFs for Customer Emissions
   Estimated emissions associated with customer side sources such as leaks and incomplete combustion. Results provided in AMM research report.
   - Project Completed: Q2 of 2023.
2. Develop Company Specific Emission Factors for Customer Meter Facilities (60 PSI or less)
   - Anticipated Project Close Out: Q2 of 2024.
3. Methane Emissions Studies (Distribution Main & Services Additional Sampling - SoCalGas and SDG&E) (SCG-2019-011)
   Develop Company-Specific EFs for buried Distribution Mains and Services (DM&S).
   - Anticipated Project Close Out: Q2 of 2024.
4. Transmission M&R Station Emission Factor Study (SCG-2021-002)
   Obtain aerial (top-down) and ground level (bottom-up) emissions profiles from transmission M&R stations to develop EFs for these facilities while also evaluating the accuracy of top-down quantification.
   - Anticipated Project Close Out: Q4 of 2024.
5. Develop Company-Specific Leak-Based EFs for Above Ground Leaks Using Concentration Method
   Determined if an accurate and reliable quantification relationship exists between leak concentration and leak rate for aboveground fugitive emissions. Results were provided in above-ground EF research report.
   - Project Completed: Q4 of 2022.

6. Geographic Leak Data Environmental Justice Analysis (SCG-2021-006)
   Determine if correlations exist between different populations in the SoCalGas service area (in terms of demographic parameters such as residential location, income, minority populations, or age) and quantity of methane emissions, especially those related to system leaks.
   - Anticipated Project Close Out: Q4 of 2024.

Lessons Learned:

- Several Company-Specific EFs were developed during the previous Compliance Periods, including EFs for transmission M&R stations, transmission compressor stations, DM&S pipelines, distribution M&R stations, and meter set assemblies (MSAs). The next phase of EF development would focus on Company-Specific EFs and/or engineering estimate methodology for transmission pipeline leaks and storage facilities. Quantifying emissions from customer leaks and incomplete combustion would also be evaluated.

New Proposed Projects:

1. Evaluate Framework for Emission Factor Maintenance and Quality Control
   - Anticipated Start Date: Q2 of 2025.
   - Anticipated End Date: Q4 of 2026.
2. Leak-Based Emission Estimate Development for Transmission Pipeline Leaks
   - Anticipated Start Date: Q2 of 2025.
   - Anticipated End Date: Q2 of 2026.
3. Evaluate Emission Estimates for Customer Leaks
   - Anticipated Start Date: Q2 of 2025.
   - Anticipated End Date: Q3 of 2026.

Part 5. Expected Results

- EFs based upon present day conditions and local leak measurements would improve emission estimates and support better strategic decisions.
- Creation of repeatable process for annual maintenance of EFs to account for any system changes.

Part 6. Emissions Impact

- Leaker-based EFs would enable more accurate emissions reporting to facilitate proper planning and resource allocation to the emissions sources that provide greater emission reductions.
- Studies quantifying emissions were conducted during previous Compliance Periods. As a result of this research, an adjustment of approximately 1,200,000 MCF has been made to the emission baseline because of inaccuracies associated with population-based factors. This continues to identify and focus efforts on mitigation strategies with a more

significant impact on methane emissions, thus improving cost effectiveness across all aspects of the NGLAP.

Part 7. Data Collection and Analysis Plan

The RD&D approach to develop Company-Specific EFs would involve a series of planned evaluations that could include one or more of the following:

a) Field Measurements
   - Determine statistically significant number of samples needed based on population of facilities and annual number of leaks as well as conduct leak measurements on a statistically random basis.
   - Evaluate leak quantification method in an actual field environment which may include controlled natural gas releases.

b) Statistically Analyze Leak Data
c) Analyze System Population and Perform Inferential Statistics
d) Develop Company-Specific EFs

Part 8. Expected Utility Total Cost

Incremental Cost Estimates (Provided in 2024 Dollars and Direct Costs)

SoCalGas

2025	2026
$1,146,975	$1,175,649

SDG&E

2025	2026
$113,437	$116,273

Rate-Recoverable Loaded Costs Submitted in Advice Letters (NGLAPBA One-Way Balancing Account)

Utility	Total Loaded Costs
SoCalGas	$3,131,121
SDG&E	$309,671

2024 SB 1371 Compliance Plan
RD&D Summary #22
Leak Prevention for Threaded Connections

Part 1. Best Practice Addressed in this Chapter

This project addresses the following Best Practice(s):

Best Practice 22: Pipe Fitting Specification & Tolerances
Utilities shall eliminate or greatly reduce emissions from metal pipe and fitting threaded connections most commonly used on aboveground facilities, such as on customer meter set assemblies and meter and regulation stations. This is accomplished with improved quality control inspection of supplier's threaded products and the application of high-performance thread sealant compounds during construction.

Part 2. Name and Type of RD&D Objective or Program Pilot

Name: Leak Prevention for Threaded Connections

Type of Objective of Program Pilot:

- Reduce emissions by reducing fugitive gas loss at threaded connections.
- Pilot studies to be initiated based on results of sealant evaluations. Pilot studies would validate actual costs and emission reductions.

Part 3. RD&D Objective

Analyze most common failure modes and components for threaded connections, especially those associated with customer MSAs. Evaluate the sealing performance of pipe thread specifications, tolerances, and sealing compounds (spray-on, brush-on, putty, or epoxy leak sealant products) for threaded fittings to lock and prevent gas leakage under varying environmental conditions, internal pressures, and external loading. Identify the technologies that can seal low pressure (7 IWC or 2 PSIG) thread leaks on existing MSAs and conduct a thorough evaluation of these products. The table below shows the primary and secondary focus areas across Transmission, Distribution, and Storage emissions that would benefit from this research.

Areas Targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
f	f		f	f	F	f	

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v – Vented

2024 SB 1371 Compliance Plan
RD&D Summary #22
Leak Prevention for Threaded Connections

Part 4. Current and Proposed Projects

Current Projects (2022 Compliance Plan):

1. Study Quality of Existing Pipe Fitting Inventory Research Project (NYSEARCH M2018-001)
   To understand the influence thread quality has on sealing performance by evaluating the thread specifications from National Pipe Taper (NPT) and Aeronautical NPT and test representative samples for sealing performance. Project also investigating workmanship, sealant application method, and applied torque to determine if these factors influence leak rate.
   - Anticipated Project Close Out: Q2 of 2024.
2. Pipe Thread Sealant Performance in Storage Applications
   To understand the effectiveness of various thread sealants on sealing performance for high pressure, high temperature storage applications. Project also investigating workmanship, sealant application method, and applied torque to determine if these factors influence leak rate.
   - Anticipated Project Close Out: Q4 of 2024.

Lessons Learned:

- Threaded connections remain an area of fugitive emissions that require further research to preemptively mitigate. Reducing the frequency of leak occurrence and simplifying the repair process are critical to reducing these emissions in a cost-effective manner.
- Data from MSA EF study could facilitate fitting replacement program for components identified to have significant leak volumes.

New Proposed Projects:

1. Threaded Connection Failure Mode Analysis
   - Anticipated Start Date: Q2 of 2025.
   - Anticipated End Date: Q4 of 2025.
2. Evaluate Threaded Connection Alternatives
   - Anticipated Start Date: Q3 of 2025.
   - Anticipated End Date: Q3 of 2026.

Part 5. Expected Results

- Reduce or eliminate fugitive methane emissions from aboveground threaded connections on customer MSAs, M&R stations, and storage facilities.
- Evaluate potential alternatives to threaded connections, such as welded assemblies, which could potentially lead to a significant reduction in leak frequency.
- Use of high-performance thread sealants could eliminate fugitive methane emissions.

2024 SB 1371 Compliance Plan
RD&D Summary #22
Leak Prevention for Threaded Connections

- Implement a threaded fitting replacement program for threaded components identified to have significant thread leaks.
- Identify the most economical thread sealants that resist leakage when exposed to varying pressure, temperature changes, vibration, and general environmental conditions that provide a cost-effective solution when considering any recommended changes to operational practices.

Part 6. Emissions Impact

- Studies quantifying emissions were conducted during previous Compliance Periods. As a result of this research, the estimated mitigation potential for this emission category is 10%-30% of the total emissions. To meet a target cost effectiveness of $22/MCF, this would require a solution with an estimated cost of $8 million, with an average mitigation cost of approximately $120 per leak event (averaged over the life of the technology).
- Applying a solution across all 6 million customer meters in the system would require a solution with an average cost of approximately $33 per meter (averaged over the life of the meter), which would only be achievable by prioritizing work on the highest emitting MSA components. Research proposed in this Compliance Plan will determine which components should be prioritized and how to cost-effectively address them through additional leak sampling and failure mode analysis.
- Potential co-benefits associated with this research include minimizing impacts to the public through avoidance of service interruptions, construction disruptions, reduced customer odor complaints, and service trips associated with this work, which leads to improved ratepayer satisfaction. These co-benefits should be considered in future implementation cost effectiveness calculations.

Part 7. Data Collection and Analysis Plan

The RD&D approach to meet the objective would involve a series of planned evaluations that could include one or more of the following:

a) Laboratory Evaluation
    - Perform laboratory evaluation to establish performance baselines and to determine which sealants proceed to the field evaluation.

b) Field Evaluation (Controlled Environment)
    - Perform field evaluation to compare to company specifications and guide the pilot study.

c) Evaluation Cost of Implementation
    - Estimate cost to conduct pilot studies.
    - Estimate emissions reduction cost reduction, and cost avoidance benefits (Go/No-Go Decision).

d) Pilot Study
    - Perform pilot study to evaluate system facilities for implementation.

2024 SB 1371 Compliance Plan
RD&D Summary #22
Leak Prevention for Threaded Connections

Part 8. Expected Utility Total Cost

Incremental Cost Estimates (Provided in 2024 Dollars and Direct Costs)

SoCalGas

2025	2026
$578,898	$608,593

SDG&E

2025	2026
$57,254	$60,190

Rate-Recoverable Loaded Costs Submitted in Advice Letters (NGLAPBA One-Way Balancing Account)

Utility	Total Loaded Costs
SoCalGas	$1,516,494
SDG&E	$149,983

2024 SB 1371 Compliance Plan
RD&D Summary #23
Evaluation of Technologies to Mitigate Gas Blowdowns & Vented Emissions

Part 1. Best Practice Addressed in this Chapter

This project addresses the following Best Practice(s):

Best Practice 23: Emissions from Operations, Maintenance and other Activities
Utilities shall minimize emissions from operations, maintenance and other activities, such as new construction or replacement, in the gas distribution and transmission systems and storage facilities. Utilities shall replace high-bleed pneumatic devices with technology that does not vent gas (i.e. no-bleed) or vents significantly less natural gas (i.e. low-bleed) devices. Utilities shall also reduce emissions from blowdowns, as much as operationally feasible.

Part 2. Name and Type of RD&D Objective or Program Pilot

Name: Evaluation of Technologies to Mitigate Gas Blowdowns and Vented Emissions.

Type of Objective(s) or Program Pilot:

- Emission reduction effort through mitigation of natural gas released during normal system operation and customer end use.
- Perform pilot projects to demonstrate efficacy of technologies and establish basis for cost effectiveness estimates.

Part 3. RD&D Objectives

Evaluate the effectiveness of various technologies (new or as discovered during records search) to mitigate vented emissions and gas blowdowns. Evaluate emissions from system components designed to have vented emissions. Identify opportunities to reduce vented emissions through improved maintenance practices, component designs, new materials, or novel solutions. Review relevant operating procedures where gas is currently released as part of the operation to identify opportunities to reduce methane emissions by changing current practices and utilizing new technology, tools and equipment, and/or practices. The table below shows the primary and secondary focus areas across Transmission, Distribution, and Storage emissions that would benefit from this research.

Areas Targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
V	V	V	V	V	V	V	V

Primary Area of Focus: F – Fugitive; V – Vented
Secondary Area of Focus: f – Fugitive; v – Vented

2024 SB 1371 Compliance Plan
RD&D Summary #23
Evaluation of Technologies to Mitigate Gas Blowdowns & Vented Emissions

Part 4. Current and Proposed Projects

Current Projects (2022 Compliance Plan):

1. Rod Packing Study (SCG-2020-003)
   Perform a study on compressor rod packing emissions examining multiple stations and collecting data in different operating conditions. Conduct a survey of the equipment and current operating practices. The data collection of this project would support multiple implementation projects (e.g., valve maintenance procedures).
   - Anticipated Project Close Out: Q3 of 2024.
2. Linear Compressor (OTD 7.20.L)
   Design, build, and test a high-pressure linear motor leak recovery compressor for cost-effective recovery of methane leaks within the transmission, storage, gathering, and processing sectors of the natural gas value chain. The linear compressor would be designed and built using a proven linear motor compressor architecture.
   - Anticipated Project Close Out: Q4 of 2024.
3. Alternative Fuel Substitution Analysis (SCG-2021-007)
   Estimate the impact on total methane emissions from the incorporation of renewable natural gas and hydrogen blending into the natural gas system.
   - Anticipated Project Close Out: Q4 of 2024.

Lessons Learned:

- Studies quantifying the vented emissions from pressure regulating components are being conducted during the 2022 Compliance Period. Cost-effective emission reduction technologies for this category need to be investigated. These technologies would focus on improved operational practices and/or replacing existing equipment/materials/components with new designs that reduce these emissions.
- Compressor-based technologies demonstrated promising potential for mitigating gas blowdowns for high pressure pipelines. The size and cost of these technologies, however, make it unfeasible for medium- and low-pressure applications. The next generation of this technology would attempt to reduce system size and cost, which would increase cost effectiveness for non-high-pressure applications.

New Proposed Projects:

1. Field Demonstrations and Evaluation of Mitigation Technologies
   - Anticipated Start Date: Q2 of 2025.
   - Anticipated End Date: Q4 of 2026.
2. Evaluate Impact of Utilizing New Technology, Tools, and Equipment on Practices and Procedures
   - Anticipated Start Date: Q2 of 2025.
   - Anticipated End Date: Q4 of 2026.

3. Develop Method for Tracking Vented Emissions at Compressor, M&R, and Storage facilities.
    - Anticipated Start Date: Q1 of 2025.
    - Anticipated End Date: Q3 of 2026.

Part 5. Expected Results

- The evaluation of various technologies to mitigate gas blowdowns and vented emissions would result in recommendations to reduce blowdown events and vented emissions.
- Opportunities that are identified during the review of operating procedures could result in recommendation to change existing practices or to utilize new practices, tools, and equipment/technology.

Part 6. Emissions Impact

- The estimated mitigation potential for blowdowns across all system categories is 1%-3% of the total emissions. To meet a target cost effectiveness of $22/MCF, this would require an average mitigation cost of approximately $14 per blowdown event (averaged over the life of the technology).
- Studies quantifying vented emissions are being conducted during the current Compliance Period but the current estimated mitigation potential for this emission category is 1%. To meet a target cost effectiveness of $22/MCF, this would require an average mitigation cost of approximately $26 per device (averaged over the life of the technology).
- Note that focusing on blowdown and vented emissions related to compressors may be more cost-effective. This represents 42% of the emissions from the above two categories, with a target cost effectiveness of approximately $493 per event/component (averaged over the life of the technology).
- Potential co-benefits associated with this research include minimizing impacts to the public through avoidance of service interruptions, construction disruptions, reduced customer odor complaints, and service trips associated with this work, which leads to improved ratepayer satisfaction. These co-benefits should be considered in future implementation cost effectiveness calculations.

Part 7. Data Collection and Analysis Plan

The RD&D approach to meet the objective would involve a series of planned evaluations that could include one or more of the following:

a) Manufacturer/In-house Demonstration
    - Facilitate demonstrations by manufacturers or set-up in-house prototypes of new technologies, tools, or equipment.

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RD&D Summary #23
Evaluation of Technologies to Mitigate Gas Blowdowns & Vented Emissions

b) Laboratory Evaluation
- Establish baseline performance for technologies, tools or equipment that are evaluated.
- Comparative evaluation to manufacturer specifications and currently approved methods.
- Evaluate the technologies, tools, or equipment to Company requirements for intended applications.
- Evaluate technologies, tools, or equipment in a simulated field environment.
- Compare to currently approved technologies, tools, or equipment.

c) Pilot Study
- Evaluate technologies, tools, or equipment in an actual field environment, including controlled natural gas releases.
- Compare to currently approved technologies, tools, or equipment.

Part 8. Expected Utility Total Cost

Incremental Cost Estimates (Provided in 2024 Dollars and Direct Costs)

SoCalGas

2025	2026
$500,146	$512,649

SDG&E

2025	2026
$49,465	$50,702

Rate-Recoverable Loaded Costs Submitted in Advice Letters (NGLAPBA One-Way Balancing Account)

Utility	Total Loaded Costs
SoCalGas	$1,324,934
SDG&E	$131,037

2024 SB 1371 Compliance Plan
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