

2020 SB 1371

COMPLIANCE PLAN





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March 16, 2020

Mr. Fred Hanes, P.E.
Senior Utilities Engineer
Safety and Enforcement Division – RASA Section
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: Leak Abatement Compliance Plan

Dear Mr. Hanes:

Southern California Gas Company (SoCalGas) submits its 2020 Leak Abatement Compliance Plan pursuant to California Public Utilities Commission (CPUC) Decision (D.) 17-06-015 and D.19-08-020 implementing Senate Bill 1371. At the CPUC's direction, the operator must submit an overall program summary highlighting their major efforts to reduce methane emissions and estimated incremental costs where known. This Section summarizes the total anticipated emission reductions from the proposed practice projected for the two-year compliance period.

SoCalGas' 2020 Leak Abatement Compliance Plan encompasses proposed activities to achieve methane emission reductions through the 26 Best Practices adopted in D.17-06-015. Proposed activities were evaluated for cost-effectiveness and emissions reduction opportunity, where data was available. Milestones were developed to achieve those emission reductions and develop a timeline for implementation where possible. Activities include policy and procedure development, training development and deployment, increased leak surveys, installation of methane sensing technologies, faster leak repair times, capture of blowdown gas, expansion of damage prevention programs, information technology projects, and development of tools to support monitoring, record-keeping, and reporting.

In addition to the major efforts outlined in Table 1, a variety of research, development, and demonstration (RD&D) projects are referenced where SoCalGas is a direct funder or provides in-kind support. These projects were proposed and initiated by leading industry organizations, including SoCalGas, in response to this proceeding and other environmental regulations targeting overall reduction of natural gas emissions. Additional RD&D projects and pilot studies are also proposed where tools and technologies require further development or where knowledge and information is needed to understand the potential for emissions reduction and to estimate the cost of implementation for SoCalGas.

Table 1, Major Efforts to Reduce Emissions, summarizes SoCalGas' proposed major activities and estimated emissions reductions proposed in the 2020 SoCalGas Leak Abatement Compliance Plan.

Table 1: Major Efforts to Reduce Emissions

Chapter	2021 Emissions Reduction, MCF	2025 Emissions Reduction, MCF	2030 Emissions Reduction, MCF	Standard Cost Effectiveness (\$/MCF)
Chapter 1 - Leak Inventory Reduction	322,711	467,512	467,512	571.54
Chapter 2 - Increased Leak Survey	129,260	153,366	153,366	33.28
Chapter 3 - Blowdown Reduction Activities	60,000	94,317	94,317	52.18
Chapter 4 - Large Leak Prioritization	54,646	54,646	54,646	26.37
Chapter 5 - Damage Prevention Algorithm and Proactive Intervention	6,060	6,060	6,060	461.35
Chapter 6 - Advanced Meter Analytics Algorithm***	37,257	37,257	37,257	6.88
Chapter 14 - Aerial Monitoring	76,834	76,834	76,834	97.55
Chapter 18 - Meter Calibration Factor***	74	74	74	N/A*
Chapter 23 - Differential Pressure Testing***	5	5	5	N/A*
Chapter 28 - High Bleed Device Replacement***	1,500	1,500	1,500	N/A**
Chapter 29 - 5-to-3 Year Leak Survey on SOTA Pipe	2,973	10,822	10,822	883.77
Summary	652,484	863,557	863,557	
Percentage Reduction	23.47%	31.06%	31.06%	

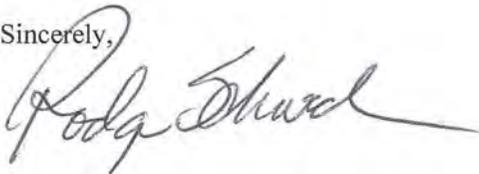
*This project has negative cost-effectiveness, because the operational benefits exceed the cost of the project

**The costs for this project are not complete as of February 2020

***The emission reductions for this project currently will not be recorded due to use of population-based Emission Factors

SoCalGas appreciates the opportunity to submit its 2020 Leak Abatement Compliance Plan and looks forward to continuing to work with the CPUC and its staff to further the goals of Senate Bill 1371 in a safe and cost-effective manner.

Sincerely,



Rodger Schewecke
Senior Vice President, Gas Operations & Construction

Introduction

SoCalGas submits this Biennial Compliance Plan on March 16, 2020 (Compliance Plan). Implementation of the activities for each Best Practice will begin after cost recovery is approved, with an expectation of implementation for 2021 – 2022.

The Compliance Plan proposes to achieve methane emission reductions through the 26 Best Practices. Proposed activities are evaluated for cost-effectiveness and emission reduction opportunity, where data is available. All requests for cost recovery 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 regulations implemented by California Air Resources Board, Environmental Protection Agency, Local Air Pollution Control Districts, and the Department of Oil, Gas, and Geothermal Resources. Some of these environmental policies overlap with SB 1371 requirements, and that overlap is addressed in the relevant chapters herein.

Emissions Reductions

The current 2015 baseline for SoCalGas' system is 2,779,851 MCF per year. Annual estimated emission reductions resulting from activities proposed in this Compliance Plan from 2021 – 2030 are estimated at 863,557 MCF. Expected annual emissions in 2030, based on modeling and assumptions as stated in this Compliance Plan, are 1,916,294 MCF, an estimated 31% reduction. It should be noted that the 2015 baseline is expected to change in Q2 2020 once proposals from the 2020 Winter Workshop are reviewed. As such, the estimated percentage reduction will likely change as a result of the new 2015 baseline.

The current estimate of a 23% reduction in emissions from the 2015 baseline by 2025 and 31% by 2030 is based on emissions models of the Compliance Plan. However, there is insufficient data to model emission reductions for many of the proposed activities. In addition, the existing models may not be entirely accurate, and the projected reduction may be higher or lower in actual practice. For example, there are measures where emission reductions cannot be calculated but emissions may be reduced by the proposed activities, such as improved training, policy changes and project bundling, and better record keeping. Additionally, some measures may have overlapping emission reductions, such as Chapters 4 and 14. As proposed research projects and pilots are completed, more accurate modeling may be available for activities such as the installation of methane sensors, transmission pipeline leaks, repairs of minor leaks, and above ground leak inspection and repair.

For SoCalGas' 2018 Annual Emissions Report, 56% of emissions were based on population, facility, or component-based emission factors. Some of the reductions targeted in this plan are fugitive emissions, which are estimated using emission factor-based models. The emission factor estimates currently in use in these models cannot be changed without approval from the California Public Utilities Commission. Since almost all fugitive emissions are based on emission factors, projecting and recording more than a 31% reduction will not be possible until these emission factors are addressed.

It should be noted that, in most cases, SoCalGas is unable to evaluate historical cost-effectiveness due to implementation still being in progress. Revenue requirements can only be accurately calculated for historical measures when the measure is completed.

Table 1, Major Efforts to Reduce Emissions, summarizes SoCalGas' proposed major activities and estimated emissions reductions proposed in the 2020 SoCalGas Leak Abatement Compliance Plan.

Table 1: Major Efforts to Reduce Emissions

Chapter	2021 Emissions Reduction, MCF	2025 Emissions Reduction, MCF	2030 Emissions Reduction, MCF	Standard Cost Effectiveness (\$/MCF)
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Calculating Cost Effectiveness

All cost effectiveness calculations used average annual revenue requirement, which was modeled by SoCalGas based on data from December 2019. Annualized revenue requirement is calculated by dividing the cumulative revenue requirement for each measure by the useful life of the measure or asset.

Standard Cost Effectiveness:

$$\frac{\text{Annualized Rev Req} * 10 \text{ years} - \text{Cost Benefits}}{\text{Emissions Reductions, 2021 - 2030}}$$

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

Cost Effectiveness with avoided Cap & Trade Costs:

$$\frac{\text{Annualized Rev Req} * 10 \text{ years} - \text{Cost Benefits} - \text{Avoided Cap \& Trade Costs}}{\text{Emissions Reductions, 2021 - 2030}}$$

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

$$\frac{\text{Annualized Rev Req} * 10 \text{ years} - \text{Cost Benefits} - \text{Avoided Cap \& Trade Costs} - \text{Social Cost of Methane}}{\text{Emissions Reductions, 2021 - 2030}}$$

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. Full Time Equivalent (FTEs) are internal company employees and their 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.
2. Vehicle costs for employees are included in the loaders for employees and, therefore, are not specifically line itemed, unless noted otherwise.
3. Cost estimates were created in December 2019 dollars and loaded with December 2019 loading factors.
4. When measures benefit both SoCalGas and SDG&E and the cost split is unknown, the costs are assumed to be 91% SoCalGas and 9% SDG&E. This percentage split was calculated based on the 2016 Emissions Inventory (reported in 2017) to remain consistent with the 2018 Compliance Plan.
5. The social cost of methane used was \$21/MCF, as noted on page 16 of D.19-08-020 for the year 2020 at a 3% discount rate.
6. 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.
7. Cap & Trade costs are \$20.82/MTCO_{2e}, assuming December 2022 vintage prices, based on a 5-day average of trading days January 6 – 10, 2020. This futures data was acquired from the International Exchange. Converting from MTCO_{2e} to MCF results in a cost benefit of \$13.61/MCF.
8. All loaded chapter costs include a 10% contingency, as noted in the Advice Letter and each chapter cost summary section.

SoCalGas Table of Concordance

Chapter	Best Practices Addressed	Subject	Page Number
1	21	Leak Inventory Reduction	10
2	15, 16	Increased Leak Survey	14
3	23, 3-7	Blowdown Reduction Activities	20
4	15, 16, 20a, 21	Large Leak Prioritization	26
5	24, 25, 26	Damage Prevention Algorithm & Proactive Intervention	31
6	17	Advanced Meter Analytics Algorithm	35
7	9	Recordkeeping IT Project	39
8	9, 20b	Geographic Tracking	45
9	13	Competency Based Training Development	48
10	13	Training Facility Enhancements	51
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12	18	Stationary Methane Detectors	56
13	20b	Electronic Leak Survey	59
14	15, 16, 20a, 21	Aerial Monitoring	62
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Chapter	Best Practices Addressed	Subject	Page Number
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20	20b	Public Leak Maps	79
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22	23	Vapor Collection Systems	82
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26	11, 12	Methane Emissions Training	91
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SoCalGas Attachment Library

Attachment	Chapter	Attachment Name
A	1 - Leak Inventory Reduction	Updated Gas Standard 223.0125
B	1 - Leak Inventory Reduction	Red-lined Gas Standard 223.0125
BB	1 - Leak Inventory Reduction	Leak Inventory Extension list
C	2 - Increased Leak Survey	Updated Gas Standard 223.0100
D	3 - Blowdown Reduction Activities	Updated Gas Standards
E	4 - Large Leak Prioritization	Emission Reduction Calculations for Accelerated Large Leak Repairs in 2020
F	5 - Damage Prevention Algorithm and Proactive Intervention	Historic Project Schedule for Damage Prevention
G	6 - Advanced Meter Analytics Algorithm	Business Case Estimation
H	6 - Advanced Meter Analytics Algorithm	Advanced Meter Presentation
I	7 - Recordkeeping IT Project	Historic Project Schedule for Data Lake
J	8 - Geographic Tracking	Historic Project Schedule for Geographic Tracking
K	8 - Geographic Tracking	Proposed Schedule for the 2021-2022 implementation
L	9 - Competency Based Training Development	Historic Project Schedule for Performance Focused Training Program
M	9 - Competency Based Training Development	Presentation of Performance Focused Training Program
N	11 - Storage Projects	Storage Operations Project Schedule 2018-2020
O	12 - Stationary Methane Detectors	Historic Project Schedule for Stationary Methane Sensor Project
P	12 - Stationary Methane Detectors	Presentation of Stationary Methane Sensor Project
Q	13 - Geographic Tracking	Historic Project Schedule for Electronic Leak Survey
R	13 - Geographic Tracking	Presentation of Electronic Leak Survey
S	14 - Aerial Monitoring	Technical specifications for Bridger Photonics LiDAR Technology

T	14 - Aerial Monitoring	Aerial Survey Emission Reduction Estimates
U	15 - Damage Prevention Public Awareness	Line Item Cost Breakdown
V	15 - Damage Prevention Public Awareness	Historic Project Schedule for Damage Prevention
W	16 - Pipe Fitting Specifications	Historic Project Schedule for Pipe Fitting Specifications
X	17 - Dig-Ins and Repeat Offenders	Historic Project Schedule for Repeat Offender System
Y	18 - Meter Calibration Factor	Historic Project Schedule for Meter Calibration
Z	19 - Enhanced Methane Detection	Historic Project Schedule for Enhanced Methane Detection
AA	21 - Greenhouse Gas Policy Update	Updated SoCalGas Environmental Excellence Policy
AB	22: Vapor Collection Systems	Historic Project Schedule for Blythe Compressor Station Vapor Recovery System
AC	23 - Differential Pressure Testing	Gas Standard 185.0347
AD	23 - Differential Pressure Testing	Gas Standard 107.0313
ADD	23 - Differential Pressure Testing	Historic Project Schedule for Differential Pressure Testing
AE	24 - Distribution Above Ground Leak Survey	RMLD Technical Specifications
AF	24 - Distribution Above Ground Leak Survey	Gas Standard 184.0275 Inspection Schedule
AG	25 - Storage Above Ground Leak Survey	TVA Specifications
AH	26 - Methane Emissions Training	Historic Project Schedule for Implementation of Methane Emissions Training
AI	27 - Distribution Above Ground Leak Repair	Updated Gas Standard 223.0126
AJ	28 - High Bleed Device Replacement	Historic High Bleed Pneumatic Devices Project Schedules
AK	29 - Leak Inventory Reduction	Redlined Gas Standard 223.0100 Leak Inventory Reduction
AL	Research & Development	Research & Development Templates

2020 SB1371 Compliance Plan
CHAPTER 1: Leak Inventory Reduction

Part 1. Evaluate the Current Practice Addressed in this Chapter

This Chapter addresses the following Best Practice:

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.

Over the years, SoCalGas accumulated an inventory of non-hazardous leak indications. Prior to the SB 1371 Proceeding, SoCalGas made efforts to reduce this inventory. SoCalGas created a Project Management Team in 2017, which centralized leak inventory reduction efforts and hired leakage-focused crews to gain efficiency through leak repair repetition. The Project Management Team tracked the costs of leak repairs, field crew productivity, and communicated the leak inventory efforts to municipalities for awareness. This work was also performed by prioritizing and performing main replacements on main segments identified to have both historical leakage as well as multiple leaks. Additionally, this effort also focused on repairing leaks based on detection year and targeted the oldest leaks.

Leak repair timeframes are required to meet safety standards prescribed in 49 CFR 192. All repairs proposed in this chapter are incremental to safety and regulatory requirements.

In the 2018 Compliance Plan, SoCalGas requested and was approved to expand this project management team and hire incremental leakage crews to expedite leak repair and reduce the inventory to less than three years by June 15, 2020.

To support these efforts, SoCalGas has staffed 36 field leakage personnel, two (2) Field Supervisors, six (6) Leakage Clerks, and four (4) Planning Associates. This is in addition to the previously hired Project Management Team which includes four management employees and 36 field leakage personnel, for a total of 88 employees dedicated to reducing the nonhazardous leak inventory. SoCalGas has purchased vehicles and tools for the incremental employees and most of the incremental staff has completed required training.

There are some situations where leaks in the Code 3 inventory are very costly or complex to repair due to permitting, size and scope of main alterations/replacements for certain leaks, right-of-way issues and/or city moratoriums. Pursuant to Decision 17-06-015 BP 21, SoCalGas requests reasonable exceptions for these repairs. A summary of these leaks where extensions are being requested, including forecasted repair dates and reason for extensions, can be found in Attachment B1.

2020 SB1371 Compliance Plan
CHAPTER 1: Leak Inventory Reduction

Emission Reductions Achieved

The Distribution Pipeline Graded Leak Emissions reported in 2015 (baseline) was 541,419 MCF¹. The Distribution Pipeline Leak Emissions for Graded Leaks reported in the calendar year 2018 was 505,124 MCF², an estimated reduction of 36,295 MCF. The majority of the work completed in 2018 was funded through the GRC and not recorded to the Leak Abatement Balancing Accounts.

The reduction forecasted to be achieved from reducing the below ground leak inventory by the end of 2019 in the 2018 Amended Compliance Plan was 120,685 MCF. Evaluation of the emission reductions achieved in 2019 have not be validated and is expected by June 2020, when the Annual Emissions Report is complete.

Cost Effectiveness Evaluation on Historic Work

The majority of the work completed in 2018 was funded through the GRC and not recorded to the Leak Abatement Balancing Accounts. Cost effectiveness for 2019 cannot be evaluated at this time due to insufficient data.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes a new goal of reducing to a 15-month inventory by the end of 2022. This goal will bring the repair timeframe for Code 3 steel leaks to be in line with the repair timeframe for Code 3 plastic and Code 2 leaks.

If a 15-month inventory goal is achieved before the end of this Compliance period, SoCalGas proposes to continue to expand the measure to achieve more aggressive leak repair goals for Code 3 steel leaks, Code 3 plastic, and Code 2 leaks. In addition to leak inventory reduction, SoCalGas proposes funding incremental leak repairs on increased leaks (for all codes) forecasted to be detected due to increased leak survey, as discussed in Chapters 2, 4, 14, and 29.

In addition to the previously hired employees, SoCalGas proposes expanding the Project Management Team by two incremental employees to provide more oversight and strategy to achieve these goals. The necessary tools and vehicles have already been purchased. No operational changes are necessary for this Compliance period beyond continuing the inventory reduction work to meet the more aggressive proposed goals.

Gas Standard 223.0125 was previously updated to reflect the three-year repair requirements (See Attachment A). It will need to be further revised to reflect the 15-month repair requirements proposed. A red-lined version of the Gas Standard is included as Attachment B.

¹ SoCalGas Natural Gas Leakage Abatement 2016 Annual Report; available at https://www.socalgas.com/regulatory/documents/r-15-01-008/SCG_Appendix8_Summary_Tables_Rev%203_09.09.16.pdf

² 2019 SoCalGas Annual Report, Appen. 4 (Distribution Mains Services) at p. 1 (pipeline leaks summary showing sum of graded leak total for both emissions carried over from prior years and emissions from leaks discovered in the year of interest); available at (https://www4.socalgas.com/regulatory/documents/r-15-01-008/R1501008_SCG-2019_Annual_Report_Appendix_4_Distribution_Mains_Services.pdf).

2020 SB1371 Compliance Plan
CHAPTER 1: Leak Inventory Reduction

Project Milestones

- Update Gas Standard (estimated by January 2021)
- Hire incremental project management employees (estimated by January 2021)
- Achieve 24-month leak inventory (estimated by December 2021)
- Achieve 15-month leak inventory (estimated by December 2022)

Part 3. Abatement Estimates

SoCalGas estimates that the emission reductions achieved by reducing the leak inventory to 15 months will result in a total emission reduction of 232,549 MCF from the 2015 baseline of 548,600 MCF. This amount includes emission reductions that were achieved during the 2018 Compliance Plan period. The incremental amount to be achieved during this Compliance period is estimated at 92,709 MCF. These emissions will be reduced from the Pipeline Leaks Emission Source Category within the Distribution Mains and Services System Category, by summing the Graded Leaks Total. The emission reduction estimate was forecasted using the emission factors from the Annual report and applying a shorter time to repair.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Leak Repair Labor	\$5,253,000	\$10,814,000	\$5,253,000	\$10,814,000	\$47,880,998
Leak Repair Nonlabor	\$7,880,000	\$9,715,000	\$7,880,000	\$9,715,000	
Project Management Office Labor	\$600,000	\$1,235,000	\$600,000	\$1,235,000	

Capital Cost Estimates					
Activity	2021		2022		Total Loaded Capital Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Service Replacement Labor	\$2,606,000	\$3,726,000	\$2,606,000	\$3,726,000	\$33,264,000
Service Replacement Nonlabor	\$6,080,000	\$8,694,000	\$6,080,000	\$8,694,000	
Main Replacement Labor	\$566,000	\$810,000	\$566,000	\$810,000	
Main Replacement Nonlabor	\$1,322,000	\$1,890,000	\$1,322,000	\$1,890,000	

2020 SB1371 Compliance Plan
CHAPTER 1: Leak Inventory Reduction

Total Revenue Requirement over expected life of investment: \$111 million
Average Annual Revenue Requirement: \$26 million

Cost Assumptions

- Each leakage crew can repair 12.5 leaks per month
- Average O&M leak repair cost is \$3,500 per leak
- Average service replacement cost is \$10,000
- Average main replacement cost is \$50,000
- 76% of leaks can be repaired using O&M
- 23% of leaks are on services and will require a service replacement
- 1% of leaks will require a main replacement
- 10% Contingency is included in the total loaded O&M and Capital cost

Part 5. Cost Effectiveness/Benefits

Standard Cost Effectiveness Calculation
\$571.74/MCF

Standard Cost Effectiveness Calculation including Cap and Trade Cost Benefits
\$568.82/MCF

Standard Cost Effectiveness Calculation including Social Cost of Methane Benefits
\$564.62/MCF

Part 6. Supplemental Information/Documentation

Attachment A: Current Gas Standard 223.0125

Attachment B: Red-lined Gas Standard 223.0125

Attachment BB: Leak Inventory Extension List

2020 SB1371 Compliance Plan
CHAPTER 2: Increased Leak Survey

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practices:

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 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.

Leak surveys on distribution lines have historically been performed according to the requirements in 49 CFR 192.723 for safety reasons. SoCalGas pipelines are typically leak surveyed at intervals of one, three, or five 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 Pre-1986 Aldyl-A pipe from 5-year and 3-year to annual. This activity was funded by the Distribution Integrity Management Program (DIMP).

In the 2018 Compliance Plan, SoCalGas requested and was approved to move unprotected steel pipe from three-year to annual leak survey cycles. To support these efforts, SoCalGas staffed the following dedicated employees:

Thirteen (13) Construction Technicians;
Two (2) Field Operations Supervisors; and
Two (2) Quality Assurance Employees.

2020 SB1371 Compliance Plan
CHAPTER 2: Increased Leak Survey

SoCalGas purchased vehicles and tools for the incremental employees and all of the incremental staff have completed required training. Because increased survey will increase the number of leaks found, SoCalGas also staffed incremental leakage personnel as outlined in Chapter 1 to support incremental leak repair.

In addition to surveying efforts above, a considerable amount of additional employee time is required for updating internal reporting and mapping systems (SAP & GIS) to update leak survey maps as a part of the increased survey cycle. Updating map systems requires incremental leak survey to levelize the survey requirements across each month. This effort to levelize the survey maps is planned to be completed in 2020. The cost for this levelization is covered in Chapter 29 since efforts to levelized survey maps for Post-86 Plastic and protected steel pipe will occur simultaneously in order to be most cost effective.

Gas Standard 223.0100 was updated to reflect the annual survey cycles for unprotected steel and Non-State Of The Art (NSOTA) plastic pipe. A red-lined version of the Gas Standard is included as Attachment C.

Emission Reductions Achieved

SoCalGas has not had the opportunity to evaluate emission reductions for annual survey on unprotected steel due to full implementation beginning in 2020.

The portion of emissions associated with Pre-86 Aldyl-A in the 2015 baseline Distribution Pipeline Leak Emissions was 93,666 MCF. The reduction achieved in 2018 after 1 year of annual survey performed on Pre-86 Aldyl-A was 35,836 MCF, compared with the forecasted reduction of 16,749 MCF.

Cost Effectiveness Evaluation of Historic Work

Cost effectiveness cannot be calculated at this time for unprotected steel annual survey because SoCalGas has not had the opportunity to evaluate emission reductions due to full implementation beginning in 2020.

Regarding the annual survey of Pre-86 Aldyl-A, no costs were recorded to this program because this effort was funded through DIMP. Therefore, there is insufficient data to calculate cost effectiveness.

2020 SB1371 Compliance Plan
CHAPTER 2: Increased Leak Survey

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to continue performing annual leak survey on unprotected steel and Pre-86 Aldyl A pipe. SoCalGas is not requesting additional funds for the Pre-86 Aldyl-A survey in this program.

The activities proposed in this measure can be 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 operational changes are necessary beyond continuing implementation of the increased leak survey cycles.

Part 3. Abatement Estimates

SoCalGas estimates that the emission reductions achieved by increasing leak survey cycles on unprotected steel and Pre-86 Aldyl-A to annual survey cycles will result in a total emission reduction of 149,672 MCF from the 2015 baseline by the end of this Compliance period. These emissions will be reduced from the Pipeline Leaks Emission Source Category within the Distribution Mains and Services System Category.

Scenario	Baselines Emissions (MCF)	Estimated Emission Reductions (MCF)					
		2018	2019	2020	2021	2022	2023
Year	2015						
Non-State of the Art Plastic (Pre-86 Aldyl-A) Pipe from 5 Yr to 1 Yr	93,666	35,836	44,657	61,060	61,060	61,060	61,060
Unprotected Steel 3 Yr to 1 Yr	190,994	0	0	29,916	66,928	88,612	89,066

2020 SB1371 Compliance Plan
CHAPTER 2: Increased Leak Survey

Calculation Methodology:

The calculation methodology used to calculate the estimated reduction in emissions is the same methodology used to calculate emissions from the distribution system in the Annual Emissions Report.

1. Derive the annual system leak rates by materials and facilities
2. Estimate the number of leaks detected and their associated emissions when shifting the survey cycle from 5-year and 3 year to annually
3. Project emissions reduction in future years during and after implementation of this Best Practice

This methodology is based on the assumptions that:

- Leaks develop on the system at a linear rate over the entire leakage survey cycle
- O&M leaks are assumed will not have an impact in the emissions reduction estimation
- All leaks are assumed to have been leaking since the beginning of the year at the full emission factor leak rate
- Known system leaks are allocated to the various leak survey cycles based on the annual system leak rate
- The number of unknown leaks is assumed to be zero since there are no areas that are not surveyed during the year of interest
- The 2016 emissions inventory is used as the baseline due to changes in reporting templates made from the 2015

2020 SB1371 Compliance Plan
CHAPTER 2: Increased Leak Survey

Part 4. Cost Estimates

Cost estimates below include only costs associated with annual survey cycles on unprotected steel. SoCalGas is not requesting funding for Pre-86 Aldyl-A survey in this program.

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Incremental Leak Survey Field Employees	\$1,089,899	\$2,688,766	\$1,089,899	\$2,688,766	\$8,665,586
Incremental Leak Survey Supervisors	\$202,400	\$500,055	\$202,400	\$500,055	
Incremental QA Employees	\$303,600	\$750,082	\$303,600	\$750,082	

Total Revenue Requirement over expected life of investment: \$9.4 million

Average Annual Revenue Requirement: \$4.7 million

Cost Assumptions

- 6,114 feet surveyed per day
- Represented Employee Hourly Rate: \$39.73
- 13 Incremental Leak Survey field FTE's
- 3 Incremental Survey Supervisors
- 2 Quality Assurance FTE's
- \$100K annual salary for Supervisors and QA employees
- 10% contingency is included in the total loaded O&M cost

Part 5. Cost Effectiveness/Benefits

Determine cost effectiveness in dollars per MSCF using the Average Annual Revenue Requirement from Part 4 as the cost basis, divided by the corresponding emission reductions.

Standard Cost Effectiveness Calculation

\$33.28

Standard Cost Effectiveness Calculation including Cap and Trade Cost Benefits

\$30.56

Standard Cost Effectiveness Calculation including Cap and Trade Cost Benefits and Social Cost of Methane Benefits

\$26.36

2020 SB1371 Compliance Plan
CHAPTER 2: Increased Leak Survey

Part 6. Supplemental Information/Documentation

Attachment C: Updated Gas Standard 223.0100 highlighted to reflect updates regarding new leak survey cycle for NSOTA plastic and unprotected steel.

2020 SB1371 Compliance Plan
CHAPTER 3: Blowdown Reduction Activities

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practices:

Best Practice 23: Minimize Emissions from Operations, Maintenance, and Other Activities
Best Practice 23: 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 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 and underground storage infrastructure consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of Compliance Plan filing.
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. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.
Best Practice 5: Methane Evacuation Procedure
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 and how to use them consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.
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. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.
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

2020 SB1371 Compliance Plan
CHAPTER 3: Blowdown Reduction Activities

sources of supply to reliably serve customers. Company policy shall define situations where work bundling is not practicable. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

SoCalGas has documented use of cost-effective methods to reduce blowdown since 1993 during operations on high pressure construction projects, including pressure reduction using mobile compressors, transfer of gas to lower pressure systems, and isolation of sections 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. Typically, operators block the smallest possible linear section of the pipeline and depressurize it by venting gas to the atmosphere. Using pump-down techniques to lower gas line pressure before performing maintenance and repair activities is an effective way to reduce emissions and yield significant economic savings. Pipeline pump-down techniques involve using in-line compressors either alone or in sequence with portable compressors. Using in-line compressors is generally justifiable because there are no capital costs, and payback is immediate. The cost-effectiveness of also using a portable compressor to increase gas recovery depends greatly on site-specific factors and operating costs. Regardless of the pump-down technique selected, emission reductions are directly proportional to how much pipeline pressure is reduced before venting occurs. Pipeline pump-down techniques are most economical for larger volume, higher pressure gas lines and work most effectively for planned maintenance activities and cases in which sufficient manifolding exists to connect a portable compressor.

In the 2018 Compliance Plan, SoCalGas requested and was approved for funding to continue blowdown reduction efforts. SoCalGas was also approved to increase the capabilities of blowdown gas capture. This includes but is not limited to expanding a centralized blowdown reduction organization, purchasing compressors and ZEVAC units to reduce blowdown emissions, increasing field operations staffing to support the incremental time to reduce blowdown, and creating a record keeping and compliance process to document that the requirements of the Best Practices were being met.

To support these efforts, SoCalGas is in the process of staffing positions across several departments. The capabilities of a centralized organization are being expanded and include staffing of:

- One (1) Team Lead
- Two (2) Project Managers
- Two (2) Construction Managers
- Three (3) Project Advisors
- One (1) Electrician
- Two (2) Technicians

SoCalGas is also increasing staffing in operational groups to support the increase in blowdown reduction. By the end of 2020, SoCalGas expects to have hired:

- One (1) Project Manager
- One (1) Instrument Specialist

2020 SB1371 Compliance Plan
CHAPTER 3: Blowdown Reduction Activities

One (1) Field Supervisor
 Two (2) Pipeline Technicians

In addition to staffing efforts several Gas Standards were updated to increase blowdown reduction efforts as outlined in Best Practices 3-7. The Gas Standards are included as attachments and are as follows:

- GS 183.01 - Shutdown Procedures and Isolation Area Establishment for Distribution Pipeline Facilities
- GS 184.06 Gas-Handling and Pressure Control
- GS 184.006 - General Construction Requirements for Distribution Service Lines
- GS 182.0160 - Purging Pipelines and Components
- GS 184.0015 - Construction Planning for Mains and Supply Lines
- GS 223.0145 - Planning Shutdowns for Transmission and Storage
- G7909 - Purging Pipelines and Components
- Form 3466 - Reporting of Gas Blown to Atmosphere
- Form 7011 - Blowdown Emission Reduction Plan Form

Emission Reductions Achieved

Blowdown Emissions reported for Transmission Pipelines, M&R Stations, and Compressor Stations as the baseline in 2015 was 207,333 MCF¹. In the calendar year 2018, emissions from these categories totaled 177,360 MCF², an estimated reduction of 29,973 MCF. These reductions were achieved using GRC funds and was not charged to the Leak Abatement Balancing Account.

System Category	2015 Emissions (MCF)	2018 Emissions (MCF)	Emission Change 2015-2018 (MCF)
Transmission Pipelines	199,970	141,863	-58,107
Transmission M&R Stations	95	24,738	24,643
Transmission Compressor Stations	7,268	10,759	3,491
Total	207,333	177,360	-29,973

The reduction forecasted to be achieved from Transmission blowdown reduction by the end of 2019 in the 2018 Compliance Plan was 45,124 MCF. Final emissions reductions achieved by the end of 2019 will not be finalized until June 2020 when the 2020 Annual Emissions Report is due. Because the emissions from Blowdown Reduction are activity based, it is difficult to forecast emission reductions.

¹ SoCalGas 2015 Annual Emissions Report Template 4.

² SoCalGas 2019 Annual Report Template 4, Pipeline Leaks Summary.

2020 SB1371 Compliance Plan
CHAPTER 3: Blowdown Reduction Activities

Cost Effectiveness Evaluation of Historic Work

The cost-effectiveness of this measure cannot be calculated at this time due to insufficient data.

Part 2. Proposed New or Continuing Measure

SoCalGas requests funding to continue to increase the capabilities of the centralized organization responsible for high pressure pipeline blowdown reduction efforts. SoCalGas will continue to combine work on high pressure lines when it is practical to do so and will coordinate projects across departments. SoCalGas also proposes the implementation of electronic blowdown reduction recordkeeping to better track and conduct blowdown reduction efforts.

Incremental work includes but is not limited to expanding the gas capture program to include capture on more projects, increasing the use of cross compression, additional funding for labor due to the increased time required for blowdown reduction, and capital work including installing fittings on valves to expand cross compression capabilities. In addition, there is an increased need to improve data collection and recordkeeping for blowdown reduction to improve capabilities for planning blowdown reduction and monitor progress and cost effectiveness. SoCalGas proposes to develop an electronic form to plan blowdown reduction efforts and improve data aggregation and analysis.

The activities proposed in this measure can be achieved by further expanding the capabilities of the centralized blowdown reduction organization. This includes staffing the following additional employees: two (2) Construction Managers; one (1) Project Manager; and two (2) Project Advisors.

Project Milestones

- Hire Construction Manager & Project Advisor: Estimated by Q1 2021
- Complete Electronic Blowdown Reduction Recordkeeping: Estimated by Q4 2021
- Hire Construction Manager, Project Manager and Project Advisor: Estimated by Q1 2022

Part 3. Abatement Estimates

SoCalGas estimates that the emission reductions achieved by increasing blowdown reduction activities will result in a total emission reduction of 65,498 MCF from the 2015 baseline of 207,333 MCF. These emissions will be reduced from the Blowdown Emission Source Category within the Transmission Pipeline, Transmission M&R Stations, and Transmission Compressor Stations Category. The emission reductions are calculated using the emission factors from the Annual report and applying a shorter time to repair.

2020 SB1371 Compliance Plan
CHAPTER 3: Blowdown Reduction Activities

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost
	Direct	Loaded	Direct	Loaded	
Incremental Field Employees	\$310,527	\$639,251	\$310,527	\$639,251	\$5,728,955
Incremental Supervisors	\$242,400	\$496,478	\$242,400	\$496,478	
Improve Data Collection Tools & Software	\$240,000	\$304,578	\$0	\$0	
Gas Capture Centralized Organization	\$545,000	\$1,069,302	\$659,000	\$1,288,192	

Capital Cost Estimates					
Activity	2021		2022		Total Loaded Capital Cost
	Direct	Loaded	Direct	Loaded	
Minimize Blowdowns in Transmission	\$2,500,000	\$3,132,250	\$3,000,000	\$3,758,700	\$8,005,448
Gas Capture Centralized Organization	\$155,000	\$161,572	\$216,000	\$225,158	

Total Revenue Requirement over expected life of investment: \$27.5 million

Average Annual Revenue Requirement: \$3.5 million

Cost Assumptions

- Annual cost of \$100K per management FTE
- Average rate of \$41.47 per Field FTE
- Centralized organization (All management)
- Seven (7) FTE's in 2020
- Two (2) added FTE's in 2021 (9 total)
- Three (3) added FTE's in 2022 (12 total)
- Transmission Operations
- One (1) Supervisor (Management)
- One (1) Project Manager (Management)
- Three (3) Field Employees
- Increase of 20% per year of projects minimizing blowdowns in High Pressure Pipelines (23 projects in 2021 and 27 projects in 2022)
- 10% contingency included for total O&M and Capital cost

2020 SB1371 Compliance Plan
CHAPTER 3: Blowdown Reduction Activities

Part 5. Cost Effectiveness/Benefits

Standard Cost Effectiveness Calculation
\$52.18

Standard Cost Effectiveness Calculation including Cap and Trade Cost Benefits
\$49.46

Standard Cost Effectiveness Calculation including Social Cost of Methane Benefits
\$45.26

Part 6. Supplemental Information/Documentation

Attachment D: Updated Gas Standards

GS 183.01 - Shutdown Procedures and Isolation Area Establishment for Distribution Pipeline Facilities

GS 184.06 Gas-Handling and Pressure Control

GS 184.006 - General Construction Requirements for Distribution Service Lines

GS 182.0160 - Purging Pipelines and Components

GS 184.0015 - Construction Planning for Mains and Supply Lines

GS 223.0145 - Planning Shutdowns for Transmission and Storage

G7909 - Purging Pipelines and Components

Form 3466 - Reporting of Gas Blown to Atmosphere

Form 7011 - Blowdown Emission Reduction Plan Form

2020 SB1371 Compliance Plan
CHAPTER 4: Large Leak Prioritization

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practices:

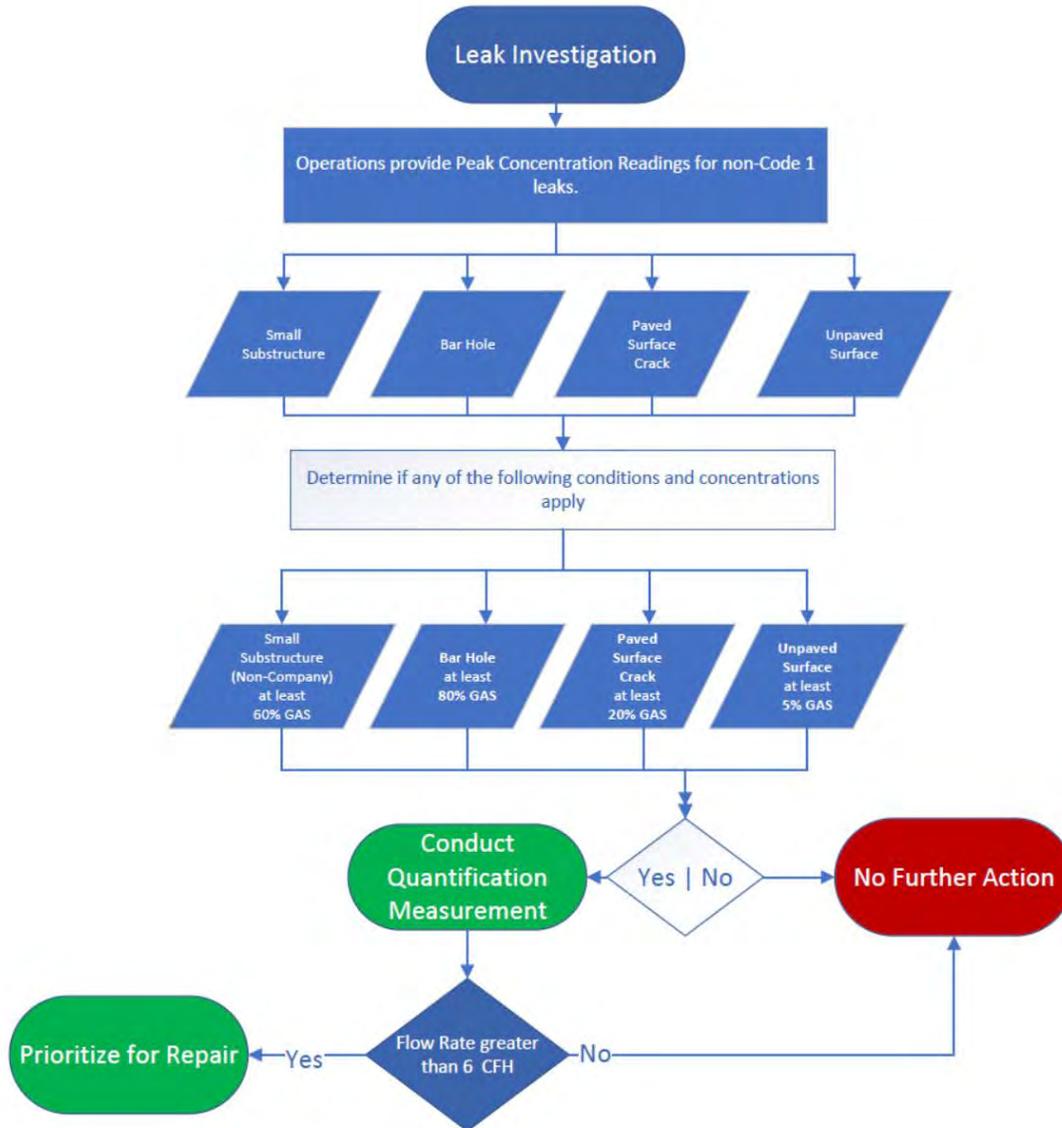
Best Practice 15: Gas Distribution Leak Surveys
Utilities should conduct leak surveys of the gas distribution system every 3 years, not to exceed 39 months, in areas where G.O. 112-F, or its successors, requires surveying every 5 years. In lieu of a system-wide three-year leak survey cycle, utilities 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 agreement on a similar methodology to improve emissions quantification of leaks to assist demonstration of actual emissions reductions.
Best Practice 21: Find It, Fix It
Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event, no 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.

SoCalGas has historically repaired leaks based on safety risk and has coded leaks as grades 1-3 based on proximity to buildings, population density, and concentration of the leak. Leak repair prioritization is based on safety and is not necessarily linked to emissions volume.

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.

2020 SB1371 Compliance Plan
CHAPTER 4: Large Leak Prioritization

In 2019, SoCalGas developed a method to identify and prioritize Code 2 and Code 3 leaks that potentially have leak rates of 10 CFH or greater. This includes development of a Decision Tree used to triage leak data from recent leak surveys to identify leaks with the greatest likelihood of being a large leak. The decision tree structure is described below.



SoCalGas implemented this program in three 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.

Early implementation of this program included training internal employees, purchasing vehicles and equipment, creating a record keeping system, and performing data analysis.

2020 SB1371 Compliance Plan
CHAPTER 4: Large Leak Prioritization

Emission Reductions Achieved

SoCalGas estimates emissions reduced by implementing this activity in the three Gas Distribution Service Districts are 753 MCF in the year 2019 or 9.17% of the emissions associated with the 225 leaks. We estimate a total emissions reduction of 54,646 MCF for the entire system implementation to be achieved per year within the next 3 years. Calculations and records of accelerated leak repair can be found in Attachment E. Emission reductions were calculated by applying the appropriate leak specific emissions rate factor derived from over 300 company specific emission measurements correlated to concentration data collected for the Decision Tree process. The analytics performed on the additional concentration data collected during the Decision Tree process allows for the leak specific differentiation and prioritization as compared to the application of a non-leak specific emission factor when no such knowledge exists.

Emission reductions will show up in Appendix 4, Pipeline Leaks Summary tab, in Emissions from Leaks Discovered in the Year of Interest for Grades 2 and 3.

Cost Effectiveness Evaluation of Historic Work

Currently there is insufficient data to evaluate cost effectiveness. The preliminary work to prepare for full-scale implementation, such as developing the Decision Tree, creating training materials, securing tools and labor, and training, did not directly result in emission reductions. SoCalGas expects to evaluate this cost effectiveness in the 2022 Compliance Plan, once the implementation has been fully implemented in Operations.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to expand this measure systemwide beginning in 2021, using data collected in leak survey to prioritize the repair of large leaks.

SoCalGas proposes to staff four full-time employees to perform surface expression measurements. One incremental employee is needed to manage the overall program and data analytics.

SoCalGas will need to make some enhancements to its IT systems to flag large leaks for quantification, and then flag them for accelerated leak repair.

Project Milestones

- Hire and train 4 Full time employees to perform surface expression measurements: Expected completion 6-12 months.
- Order 2 sets of high flow analyzers and DPIRs: Expected completion 6-12 months.
- Order 2 company vehicles: Expected completion 6-12 months.

2020 SB1371 Compliance Plan
CHAPTER 4: Large Leak Prioritization

Part 3. Abatement Estimates

SoCalGas estimates that the emission reductions achieved by prioritizing large leaks for repair will reduce emission by 54,646 MCF/year in 2021 and 2022. For these reductions to be fully captured in the Annual Emissions Report, the emission calculation methodology will need to be updated. The methodology of how the Annual Emissions Report will be updated was discussed in the 2020 workshop.

The emissions reduction estimate was obtained using the following:

1. Obtained all possible repair dates for the 239 leaks measured during the 2019 Pilot Study.
2. Leak durations were assigned to each leak according to the Leak Duration criteria described above.
3. The average leak rate (i.e. emission rate) was assigned to each leak according to the Average Leak Rate criteria above. This was used to calculate the total leak rate without the Decision Tree method applied.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Engineers for Full Implementation	\$484,800	\$969,600	\$484,800	\$969,600	\$2,766,524
Supervisor for Full Implementation	\$121,200	\$242,400	\$121,200	\$242,400	

Capital Cost Estimates					
Activity	2021		2022		Total Loaded Capital Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Tools for Surface Expression Measurements	\$150,000	\$0	\$0	\$0	\$270,245

Total Revenue Requirement over expected life of investment: \$3.6 million

Average Annual Revenue Requirement: \$1.5 million

2020 SB1371 Compliance Plan
CHAPTER 4: Large Leak Prioritization

Cost Assumptions

- \$120,000 per engineer for surface expression
- \$120,000 for supervision
- 1% of salary for nonlabor costs
- 2 sets of high flow analyzers and DPIRs estimated at \$62,500 each set (should be amortized over a 5-year life)
- 2 Company vehicles at \$12,000 each per year
- 10% Contingency is included in the total loaded O&M and Capital cost

Part 5. Cost Effectiveness/Benefits

Standard Cost Effectiveness:

\$27.37/MCF

Cost Effectiveness with avoided Cap and Trade Cost:

\$24.65/MCF

Cost Effectiveness with the avoided Social Cost of Methane:

\$20.45/MCF

Part 6. Supplemental Information/Documentation

Attachment E: Emission Reduction Calculations for Accelerated Large Leak Repairs in 2020

2020 SB1371 Compliance Plan
CHAPTER 5: Damage Prevention Algorithm and Proactive Intervention

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practices:

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.

Using the prioritized results from the risk analysis algorithm, company personnel can initiate communication with excavators to discuss the project and remind them of the importance of locating and protecting the natural gas pipe within their projects delineated area. The form of communication can be a phone call, text message, email, or job site visit, prior to the date of excavation. Through these proactive interventions, company personnel can effectively address a larger number of excavation projects rather than just performing standby. This proactive excavation intervention will enable SoCalGas to minimize methane emissions from preventable damages.

In 2019, SoCalGas utilized 4 Damage Prevention Analysts to engage, educate, and enforce 811 rules. Their work resulted in over 2,100 field contacts with excavators, over 200 educational safe excavation training sessions, and 300 damage investigations resulting in improved excavation safety.

Emission Reductions Achieved

There is insufficient data to calculate emissions reductions achieved by this measure at this time.

Cost Effectiveness Evaluation of Historic Work

There is insufficient data to calculate cost effectiveness achieved by this measure at this time.

2020 SB1371 Compliance Plan
CHAPTER 5: Damage Prevention Algorithm and Proactive Intervention

Part 2. Proposed New or Continuing Measure

SoCalGas proposes continuing to develop the damage prevention risk analysis algorithm; this information would be used to trigger a proactive intervention. Proactive interventions include activities that SoCalGas can perform to address potential excavation sites that pose a high risk of damage, causing methane emissions. Using the prioritized results from the risk analysis algorithm, company personnel can initiate communication with the excavator to discuss the project and remind them of the importance of locating and protecting the natural gas pipe within their projects delineated area. The form of communication can be a phone call, text message, email, or job site visit, prior to the date of excavation. Through these proactive interventions, company personnel can effectively address a larger number of excavation projects. This proactive excavation intervention will enable SoCalGas to minimize methane emissions from potentially preventable damages.

The existing risk algorithm that was completed in the 2018 Compliance period assigns a score for every new 811 ticket to provide SoCalGas with prompt visibility into high-risk dig sites and mark out locations. SoCalGas is proposing to make enhancements to the algorithm in the 2020 compliance period to further reduce potentially preventable damages. These planned enhancements to the algorithm include additional data layers that will provide increased benefits such as identifying:

- Excavator Error: Risk score derived from risk variables like work type, contractor name, topography, and weather conditions.
- No Call-Ins: Identification of possibly high-risk excavations without 811 ticket information, leveraging municipality permit data where data is publicly available.
- These risk scores will allow SoCalGas to prioritize and conduct appropriate and timely interventions before damages occur. The No Call-Ins analysis will provide SoCalGas visibility into repeat offenders who continue to conduct excavations without calling 811.

In order to implement these further enhancements, SoCalGas will need to hire six (6) additional Damage Prevention Analysts to perform the increased volume of proactive intervention efforts with prioritized Dig Alert tickets.

Project Milestones

- Hire and train incremental Damage Prevention Analysts: Expected to be completed by Q1 2021.
- Collect data and perform proactive interventions: Continuous.

Part 3. Abatement Estimates

Emission reductions are estimated based on the number of proactive interventions forecasted to be performed. Based on six (6) incremental damage prevention analysts averaging five (5) interventions per day, SoCalGas estimates an emission reduction of approximately 6,060 MCF per year.

2020 SB1371 Compliance Plan
CHAPTER 5: Damage Prevention Algorithm and Proactive Intervention

SoCalGas anticipates preventing approximately 300 damages per year, with an average emission of 20 MCF per damage. This forecast was calculated using vendor data from previous implementations with other utilities. Emissions would be reduced from Appendix 4, All Damages.

Assumptions

- Each damage prevention analyst can perform an average of 5 interventions per day
- Each damage prevention analyst will work 10.5 out of 12 months per year to accommodate for vacation and sick time
- SoCalGas received 841,369 tickets in 2018
- SoCalGas can intervene on approximately 1% of the 16,000 tickets with 6 analysts
- $6 * 5 * 10.5 / 12 * 5 * 52 = 6,825$ interventions
- $6,825 \text{ interventions} / 841,369 \text{ tickets} \sim 1\%$ intervention rate
- In 2018, SoCalGas reported 772 damages to PHMSA
- At a 1% intervention rate, SoCalGas projects preventing 303 damages
- Each damage emits an average of 20 MCF
- $20 \text{ MCF} * 303 \text{ damages prevented} = 6,060 \text{ MCF}$

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Incremental Damage Prevention Analysts	\$600,000	\$1,235,160	\$600,000	\$1,235,160	\$5,234,616
Risk Prevention Software Solution	\$1,137,500	\$1,144,211	\$1,137,500	\$1,144,211	

Total Revenue Requirement over expected life of investment: \$5.5 million

Average Annual Revenue Requirement: \$2.7 million

Cost Assumptions

- 6 damage prevention analysts at \$100,000 a year
- \$1,250,000 per year for damage prevention software

Cost Benefits

Repair savings of \$484,800

Repair Cost Per Damage: \$1,600 per damage * 303 prevented damages

2020 SB1371 Compliance Plan
CHAPTER 5: Damage Prevention Algorithm and Proactive Intervention

Part 5. Cost Effectiveness/Benefits

Standard Cost Effectiveness Calculation

\$461.35

Standard Cost Effectiveness Calculation including Cap and Trade Cost Benefits

\$458.63

Standard Cost Effectiveness Calculation including Social Cost of Methane Benefits

\$454.43

Part 6. Supplemental Information/Documentation

Attachment F: Historic Project Schedule for Damage Prevention Activities

2020 SB1371 Compliance Plan
Chapter 6: Advanced Meter Analytics Algorithm

Part 1. Evaluate the Current Practices addressed in this Chapter

This Chapter addresses the following Best Practice:

Best Practice 17: Advanced Meter Analytics Algorithm
Utilities shall utilize enhanced methane detection practices (e.g. mobile methane detection and/or aerial leak detection) including gas speciation technologies.

Prior to the installation of the Advanced Meter network in the SoCalGas service territory, SoCalGas' Customer Information System (CIS) would flag unusually high consumption so an order for a field technician to investigate could be scheduled within 14 days. Since the meter usage data was only read once a month, a field technician investigation could occur up to 45 days after unusually high consumption occurred.

In May of 2016, SoCalGas began using hourly usage data available through the Advanced Meter technology to identify facilities with unusual consumption patterns. Once these unusual consumption patterns are identified, an analyst reviews a report daily and manually creates orders for field technicians to visit the site of continuous excessive consumption. Field technicians perform clock tests and leak investigations and/or close and secure the service valve to prevent further leakage of natural gas. These activities have reduced the time from when unusually high consumption occurs to when an investigation occurs from up to 45 days to 48 hours.

This new and more granular awareness of energy data utilization is uncovering new opportunities and benefits potential. Leveraging the Advanced Meter network could result in faster identification of abnormally high gas usage, which enables SoCalGas to identify, investigate, and respond to potential emission sources more quickly. By discovering abnormally high gas usage and notifying customers, SoCalGas can reduce methane emissions at customer facilities, which saves energy and reduces potential climate impact, while also reducing the financial burden on customers from higher usage.

Emissions Reduction Achieved

In 2018, these efforts reduced methane emissions downstream of the meter by approximately 37,000 MCF by accelerating leak identification, notification, and repair. These emission reductions were not captured in the emission report because emissions are downstream of the meter. However, this activity will result in lower methane emissions in California which contributes to state climate goals.

Cost Effectiveness Evaluation on Historic Work

The previous efforts for this measure were funded through other mechanisms. Therefore, there is insufficient data to calculate cost effectiveness achieved by this measure at this time.

2020 SB1371 Compliance Plan
Chapter 6: Advanced Meter Analytics Algorithm

Part 2. Proposed New or Continuing Measure

SoCalGas proposes developing and implementing an algorithm and monitoring application where hourly gas consumption data from Advanced Meters will be collected and analyzed to identify gas consumption anomalies and triggers automatically scheduled field investigations for unusually high consumption. The current implementation of the Advanced Meter technology incurs a 24 to 48-hour delay from the time a Meter Transmission Unit (MTU) delivers hourly consumption data to the Advanced Meter back-office systems and processes until the time a field visit is requested, in addition to manual tracking and scheduling from an Advanced Meter analyst and a Dispatcher. This project will improve the ability to monitor consumption anomalies every hour, within 1 hour, from the time the system receives data from each Meter Transmission Unit (MTU), further reducing the turnaround time since the monitoring application would be able to automatically request a field visit to facilities with highly unusual gas consumption. This project is expected to reduce the investigation turnaround time to 12 to 18 hours and minimize the manual labor associated with current unusual consumption tracking activities. Multiple Machine & Deep Learning Models will be used to identify consumption patterns requiring a field visit for investigation and resolution. Service requests will be delivered to CIS for generation of high priority service orders for completion by field technicians.

The expected enhancements for 2021 – 2022 will include the following:

- A new Deep Learning Model to identify houeline gas leaks.
 - A Deep Learning Model is a collection of algorithms used in machine learning and artificial intelligence that imitate the way humans gain knowledge. Deep Learning algorithms are stacked in a hierarchy of increasing complexity and abstraction. By teaching a set of models what confirmed gas leaks look like, the models should be able to evaluate gas consumption data and identify gas leaks going forward.
- A new Deep Learning Model to catalog gas consumption measurements at the appliance level.
 - Understanding these patterns will help us identify anomalies that may lead to additional investigations of gas consumption at appliances unintentionally left on. As an example, a resident may have left their outside barbeque on and this model will be trained to detect these types of usage anomalies.

Project Milestones

- Design scope of work: Estimated 5 months
- Build out application: Estimated 9 months
- Application testing: Estimated 15 months
- Application deployment: Estimated 17 months

2020 SB1371 Compliance Plan
Chapter 6: Advanced Meter Analytics Algorithm

Part 3. Abatement Estimates

This measure is expected to reduce emissions by an estimated 37,257 MCF per year based on results from the initial project. These savings are based on accelerating leak findings and their subsequent repair or meter turn off. These savings will not be captured in the Emissions Report because emissions are downstream of the meter. However, this activity will result in lower methane emissions in California, which contributes to State climate goals.

For vacant facilities:

$(\text{Total Daily Usage}) * [(\text{Next Bill Date} - \text{Advanced Meter Detection (AMD) Read/Verify (R/V) Field Date}) + 14 \text{ days}] = \text{Total MCF Saved}$

Total Daily Usage: Meter Data Management System (MDMS) daily consumption usage that brought the facility into AM Analytics processes

Next Bill Date: The date when Customer Information System (CIS) processes would first have awareness to excessive consumption at a vacant facility

AMD R/V Field Date: The date the meter was hard closed or excessive consumption was identified (hot water leak) or resolved

14 Days: The minimum number of days when the previous process would have generated an order for increased consumption at a vacant facility

For occupied facilities:

$(\text{Min Hourly Consumption} * 24\text{hrs}) * [(\text{Next Bill Date} - \text{AMD R/V Field Date}) + 2 \text{ days}] = \text{Total MCF Saved}$

Min Hourly Consumption: Lowest MDMS consumption usage for the date when excessive consumption brought the facility into AM Analytics processes

Next Bill Date: The date when CIS would first have awareness to excessive consumption at an occupied facility.

AMD R/V Field Date: The date the meter was hard closed or excessive consumption was identified (hot water leak) or resolved

Days: The number of days when current CIS processes would have generated an order for increased consumption at an occupied facility

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Data Scientist	\$112,000	\$230,563	\$112,000	\$230,563	\$507,239

Total Revenue Requirement over expected life of investment: \$548,823

Average Annual Revenue Requirement: \$274,412

2020 SB1371 Compliance Plan
Chapter 6: Advanced Meter Analytics Algorithm

Cost Assumptions

- 1 employee at \$112,000 a year
- 1 FTE is allocated for a Data Scientist to provide on-call support (break/fix), maintain and enhance the Deep Learning Models running 24/7

Part 5. Cost Effectiveness/Benefits

Standard Cost Effectiveness Calculation
\$6.88

Standard Cost Effectiveness Calculation including Cap and Trade Cost Benefits
\$4.16

Standard Cost Effectiveness Calculation including Social Cost of Methane Benefits
-\$0.04

Part 6. Supplemental Information/Documentation

Attachment G: Business Case Estimation
Attachment H: Advanced Meter Presentation

2020 SB1371 Compliance Plan
CHAPTER 7: Recordkeeping IT Project

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

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.

In the past, developing the Annual Emissions Report required by SB 1371 involved querying various records which were stored in varying formats, locations, databases, and with various record owners. Different record keeping practices have evolved over time and as new record-keeping requirements emerge, various new systems have been developed. These different record-keeping systems are not always compatible, and data is not easily shared, integrated, or queried. This makes report generation a time-consuming manual process. An additional challenge is that these systems were not designed for generating reports for emissions, but rather for billing or operational record keeping. Because of this, the records may use varying types of nomenclature relevant to specific departments. Querying records from numerous departments in the company and combining them to generate a single report is quite challenging. To generate Annual Emissions Reports, data is pulled from thirty-six separate reports, which are generated from fourteen different systems. Generating an Annual Emissions Report requires four full time employees and engaging various departments to compile and analyze the data and properly format it for consistent report generation.

As proposed in the 2018 Compliance Plan, SoCalGas is implementing a central data lake that obtains records from the various systems and stores them centrally, enabling automation of reporting as well as satisfying the retention and audit requirements. SoCalGas is also developing 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.

SoCalGas has also started enhancing existing systems to include additional data elements required for the methane emissions calculations into all Maintenance and Inspection work management systems. The systems enhancement has been enabling the field personnel to record the required information into systems that previously have not been capable of recording specific information, such as detailed components. Such information enables SoCalGas to report its operational activities accurately on required reports.

SoCalGas has also conducted a field mobility project assessment. This project studied the status of the mobile capabilities of existing systems, digital forms, and paper forms in order to define the future mobility scope.

2020 SB1371 Compliance Plan
CHAPTER 7: Recordkeeping IT Project

Finally, written company policies were developed and edited to maintain records for all SB 1371 relevant measured and estimated emissions, including calculations, data, and assumptions to derive the volume of methane released.

Emission Reductions Achieved and Cost Effectiveness Evaluation

There is insufficient data to calculate emission reductions and cost effectiveness.

Part 2. Proposed New or Continuing Measure

This implementation is divided into 5 measures.

Measure 1: Data Lake

As stated in the 2018 Compliance Plan, this project will be phased in over two Compliance periods. Therefore, SoCalGas will be completing the initial data lake scope and continue to make enhancements to respond to evolving SB 1371 requirements throughout the 2021-2022 Compliance period.

As new requirements are identified, analysis, design, and development activities will include:

- Complete current data lake project scope
- Analyze and update existing data capture forms
- Design and modify existing enterprise systems to accommodate new data requirements
- Integrate system changes with the data lake
- Expand the scope of the data lake
- Back fill historical data for the entire reporting period to meet the new requirements
- Test the modified systems, integration, and reporting from the data lake
- Training and support
- Project and program manager time

Project Milestones

- Complete initial data lake scope: Estimated by Q2 2021
- Maintain and enhance the existing systems and data lake integration to capture new data for new requirements: Continuous

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CHAPTER 7: Recordkeeping IT Project

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

EDAPO's advanced analytics will provide actionable insights on gas assets' current and future performance. EDAPO will be used to detect and help prioritize leak repairs and identify areas with high leak indicators. The analytics results will become SB 1371 records and be captured and stored in the data lake. EDAPO advanced analytics will implement the tools, infrastructure and resources to drive the improvement of business operations and enable the proactive management of gas assets. EDAPO will provide capabilities that will include:

- Enable cost effective avoidance, reduction, and repair of leaks and leaking components
- Evaluate the operations, maintenance, and repair practices to increase the effectiveness of practices to reduce methane leaks
- Develop and use metrics to evaluate and track leaks geographically and over time

Project Milestones

- Identify sample data sets to be integrated: Estimated by Q1 2021
- Sample data integration for analytics: Estimated by Q4 2021
- Data Model validation/verification: Estimated by Q2 2022
- Implementation of EDAPO advanced analytics: Estimated by Q4 2022

Measure 3: Asset Field Verification

SoCalGas will also continue enhancing existing systems efforts that started in the 2018 Compliance Plan. SoCalGas will verify its assets data in the Maintenance and Inspection work management systems of various operational divisions such as Storage and Transmission. These verification efforts will enable SoCalGas to query accurate methane emissions for its Annual Emissions Report.

The Field Verification Project will include:

- Data Governance – identify appropriate Gas Standards and apply to engineering tags capture, in addition to defining lookups for entry fields where possible.
- Review engineering drawings and identify assets that need to be in verified or added
- Field verification of assets, including photos, and collection of data points needed for maintenance and work management systems
- Organize photos and data

Project Milestones

- Field verification of Transmission assets: Estimated by Q4 2021
- Field verification of Storage assets expected to be completed by Q4 2022
- Perform field verification and enhancement of Management systems assets and update engineering/mapping information to support improved data management and reporting accuracy expected to be completed by Q4 2022

2020 SB1371 Compliance Plan
CHAPTER 7: Recordkeeping IT Project

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

Project will continue to:

- Modernize real-time data management software landscape and infrastructure to improve the existing methane emission systems
- Integrate existing infrastructure with enterprise compliance reporting software to support advanced and predictive analytics
- Integrate existing infrastructure into SB 1371 solutions to enhance company's compliance with methane emission requirements
- Enable additional analytics capabilities and provide ability to integrate with other enterprise initiatives.

Project Milestones

- Design, develop, and implement real-time data management software: Continuous

Measure 5: Develop Mobile Field Forms

As part of the 2018 Compliance Plan, SoCalGas completed an assessment to evaluate the mobile capabilities of the existing system, digital forms, and paper forms. SoCalGas proposes to create digitized forms based on the assessment results. This strategy will digitize paper forms, update electronic forms, and establish a governance structure to support mobility. This measure is expected to create a simplified and consistent experience for the field employees, while increasing the accuracy of the captured data and providing near real-time integration with the associated IT systems e.g. data lake. This scope of work is expected to continue into the 2022 Compliance Plan.

Project Milestones

- Validate scope of digitizing paper forms: Estimated by Q2 2021
- Digitizing paper forms and processes: Estimated by Q4 2024
- Modernizing and enhancing existing mobile solutions: Estimated by Q4 2024

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions from this activity.

2020 SB1371 Compliance Plan
CHAPTER 7: Recordkeeping IT Project

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Measure 1	\$946,400	\$1,718,350	\$946,400	\$1,718,350	\$18,095,815
Measure 2	\$0	\$0	\$0	\$0	
Measure 3 (Storage)	\$3,288,000	\$4,932,768	\$3,288,000	\$4,932,768	
Measure 3 (Transmission)	\$1,529,440	\$3,148,505	\$0	\$0	
Measure 4	\$0	\$0	\$0	\$0	
Measure 5	\$0	\$0	\$0	\$0	

Capital Cost Estimates					
Activity	2021		2022		Total Loaded Capital Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Measure 1	\$1,345,344	\$1,353,282	\$1,345,344	\$1,353,282	\$7,296,524
Measure 2	\$176,000	\$183,462	\$176,000	\$183,462	
Measure 3 (Storage)	\$0	\$0	\$0	\$0	
Measure 3 (Transmission)	\$0	\$0	\$0	\$0	
Measure 4	\$334,050	\$338,906	\$334,050	\$334,050	
Measure 5	\$1,432,500	\$1,440,952	\$1,432,500	\$1,440,952	

Total Revenue Requirement over expected life of investment: \$29,232,114

Average Annual Revenue Requirement: \$17,675,150

Cost Assumptions

Measure 1:

- 2 years annual licensing
- Update IT systems to capture emissions data required by SB 1371
- 9 existing employees and 5 contractors needed to maintain and enhance IT systems

Measure 2:

- Development of advanced analytics
- 3 existing employees 2 contractors

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CHAPTER 7: Recordkeeping IT Project

Measure 3

Storage:

- Inventory tasks across the 4 storage fields
- 1 year of labor using 5 existing employees for storage
- 3 Contractors for QA and coordination

Transmission:

- Inventory tasks across 34 gas producer sites
- 1 year of labor using 11 existing employees

Measure 4:

- 1 existing internal employee
- 2 contractors

Measure 5:

- 1 contracted project manager
- Labor for internal subject matter experts

Part 5. Cost Effectiveness/Benefits

Cost benefits for this activity include an anticipated reduction in labor needs to generate the Annual Emission Report. There is insufficient data to quantify those benefits and calculated cost effectiveness at this time.

Part 6. Supplemental Information/Documentation

Attachment I: Historic Project Schedule for Data Lake

2020 SB1371 Compliance Plan
CHAPTER 8: Geographic Tracking

Part 1. Evaluate the Current Practices addressed in this Chapter

This Chapter addresses the following Best Practices:

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 in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

To improve capabilities of leak surveys performed at storage facilities and compressor stations, SoCalGas requested in the 2018 Compliance Plan to back model high pressure facilities in AVEVA and enable scanning technology on 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 our supply management programs to order replacement parts when needed and identify lead times for replacement, and identify if leaks are on critical system which will influence plans for repair.

In the 2018 Compliance period, SoCalGas will have completed the digitizing and mechanical walkdown of 1,200 Piping & Instrumentation Diagrams (P&IDs) for SoCalGas Storage and Compressor stations. These intelligent P&IDs will allow engineering to locate tags for equipment or instrumentation that is currently found in these facilities. Furthermore, two storage facilities will have 3D models. These are digital twins to the facilities that will allow SoCalGas to query data based on a tag, type of equipment, service, location, etc. The tags in the 3D model will link to the P&IDs, enabling proper engineering information to be provided. The 3D model will provide material information to help identify connection points and support queries for potential leak points in the existing facilities.

In the 2018 Compliance period, SoCalGas hired and trained ten (10) employees to support this effort.

Emission Reductions Achieved and Cost Effectiveness Evaluation

There is insufficient data to measure emission reductions or evaluate cost effectiveness of these activities.

2020 SB1371 Compliance Plan
CHAPTER 8: Geographic Tracking

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to continue completing updates of P&IDs and back modeling of complex high-pressure facilities. The goal of this project is to create the digital twin 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 engineering 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/service, the type of equipment and location, and the capability to connect the 3D model database systems to other SoCalGas database systems. This will enable increased ability to calculate blowdown and bundle projects for blowdown, repair leaks more quickly, and identify materials with repeated leaks, indicating requirements for replacement.

SoCalGas plans to complete approximately 800 P&IDs that were not part of the 2018 Compliance Plan. SoCalGas also plans to model three small transmission sites and two compressor stations. In 2021-2022, SoCalGas also plans to continue the Instrument & Controls (I&C) as-built for 2 storage facilities.

See Attachment K for a proposed schedule.

Part 3. Abatement Estimates

There is insufficient data to quantify emission reductions from these activities.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Gas Engineering Labor	\$1,014,000	\$2,087,420	\$1,404,000	\$2,890,274	\$14,831,002
Scanning and 3D Modeling	\$3,202,420	\$3,221,314	\$4,434,120	\$4,460,281	
Transmission Labor (PM)	\$100,000	\$205,860	\$100,000	\$205,860	
Storage Labor (PM)	\$100,000	\$205,860	\$100,000	\$205,860	

Total Revenue Requirement over expected life of investment: \$15.8 million

Average Annual Revenue Requirement: \$7.9 million

2020 SB1371 Compliance Plan
CHAPTER 8: Geographic Tracking

Part 5. Cost Effectiveness/Benefits

There is insufficient work to evaluate the cost effectiveness of these activities.

Part 6. Supplemental Information/Documentation

Attachment J: Historic Project Schedule for Geographic Tracking

Attachment K: Proposed Schedule for the 2021-2022 implementation

2020 SB1371 Compliance Plan
CHAPTER 9: Competency Based Training Development

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

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.

SoCalGas has a robust classroom training program facilitated at a centralized training facility in Pico Rivera. The training facility is equipped with an area known as Situation City where trainees can experience real world emergencies like a blowing high-pressure line with an ignition source, while in a safe and controlled environment. Training programs have historically focused primarily on DOT PHMSA safety regulations. Safety is a core value at SoCalGas and all current training programs are focused around incorporating safety in all procedures as a primary goal.

Gas Operations training follows an established, systematic approach to training development. The development of training programs at SoCalGas includes needs assessment and training analysis, which is essentially a scope of work development. Based on what is found, curriculum design and development of training materials will follow. When development is completed, implementation of instruction and internal/external evaluation begin.

In 2018, SoCalGas began redeveloping the course materials related to emissions abatement for the following roles: Construction Technician, Leak Survey, Energy Technician, Lead Construction Technician, Measurement and Regulation I, Measurement and Regulation II, Transmission Measurement and Pipeline Technician. The focus of this effort has been on transforming these courses from a traditional classroom training approach to an integrated, multimedia, performance focused instruction.

Emission Reductions Achieved and Cost Effectiveness Evaluation

There is insufficient data to estimate emission reductions and cost effectiveness from these activities.

Part 2. Proposed New or Continuing Measure

Historically, Gas Operations Training has been driven by a strong emphasis on DOT safety regulations. SB1371 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 will need to be modified and new training modules developed to support the new process and policies, and train new employees with an increased focus on the environmental impact of methane emissions on the atmosphere.

2020 SB1371 Compliance Plan
CHAPTER 9: Competency Based Training Development

SoCalGas proposes continuing to implement a competency-based training program that will encompass training design for all new methane mitigation policy and procedural changes.

SoCalGas is transitioning from a traditional classroom training approach to a competency based online/video training module system to enhance the ability to incorporate new policies and increase learning at a faster pace.

SoCalGas proposes expanding the curriculum transformation to three additional courses: Leakage Clerk, Storage Technician, and System Protection Specialist. The objectives are:

1. Incorporate new training content due to processes, procedures and policies established because of SB 1371.
2. Develop selected curriculum into multimedia, competency-based performance focused training approach that will include self-paced, individualized, modular instruction, eLearning, just-in-time training, structured and on-the-job training.
3. To improve efficiency and effectiveness, Gas Operations Training is working to develop self-paced, individualized instruction and multimedia technology for the dissemination of training and performance support (e.g., eLearning, electronic performance support, electronic testing, etc.).

This effort will require involvement of a Team Lead (40%), three (3) Instructional Designers (100%), and three (3) Instructors (30%) for 18 months.

Changes to Gas Operations Training department operations will be comprehensive. Instead of scheduling classes that start and end on specific dates on a calendar, training will operate in an open for business paradigm. The individualized instruction environment will allow students to begin training anytime and training will conclude when the student has achieved competence. The role of the instructor will change from the primary dispenser of instructional content to a facilitator of learning. Interactive, media-rich training materials will be the primary channel for students to learn training content as opposed to the current traditional classroom format. The instructor's role will transition focus efforts on coaching, mentoring, and observing hands-on activities performed by students. This new training format should increase the speed of competence development.

Project Milestones

- Establish scope of work for training modifications: Estimated 3 months
- Instructional Design: Estimated 12 months
- Development of training materials: Estimated 18 months
- Evaluations of training materials and train-the-trainer: Estimated 18 months
- Training Implementation: Estimated 18-24 months

Part 3. Abatement Estimates

There is insufficient data to calculate the emissions reductions from this measure

2020 SB1371 Compliance Plan
CHAPTER 9: Competency Based Training Development

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Costs with Contingency
	Direct	Loaded	Direct	Loaded	
Training development, web and video-based training	\$1,322,185	\$1,751,066	\$1,164,941	\$1,592,894	\$3,678,356

Total Revenue Requirement over expected life of investment: \$3.9 million

Average Annual Revenue Requirement: \$1.9 million

Cost Benefits:

Although there is insufficient data to quantify, this measure does experience cost benefits because many of the field personnel can take these trainings remotely at their home office and avoid travel expenses associated with traveling to the Pico Rivera training office.

Part 5. Cost Effectiveness/Benefits

There is insufficient data to estimate cost effectiveness for this activity.

Part 6. Supplemental Information/Documentation

Attachment L: Historic Project Schedule for Performance Focused Training Program

Attachment M: Presentation of Performance Focused Training Program

2020 SB1371 Compliance Plan
CHAPTER 10: Training Facility Enhancements

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

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.

SoCalGas has a robust classroom training program facilitated 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 simulations like a blowing high-pressure line with an ignition source, while in a safe and controlled environment. Training programs are focused primarily on DOT PHMSA safety regulations. Safety is a core value at SoCal Gas and 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 reading training, firefighting training, and much more. In this facility, SoCalGas can train students using a real working gas distribution system in a safe and controlled environment. In Situation City, gas leaks of 10 Cubic Feet per Hour (CFH) can be simulated for training purposes. These simulations were primarily created as a safety measure and were easily detectable in training. As gas emission standards have evolved, the need to detect smaller and varied size leaks has become apparent.

Emission Reductions Achieved and Cost Effectiveness Evaluation

While this activity supports emission reduction efforts, there is insufficient data to calculate emission reduction and cost effectiveness from these activities.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes that modifications to the leak simulation system at Situation City be implemented to facilitate detection of leaks of varying sizes to enhance trainee leak detection skills and meet the training needs of SB1371. When the system was installed, there were no specifications for minimum detectible leak size. SB1371 requires that leaks as small as .01 CFH be detected. Situation City's leak simulation system can be activated by instructors to provide students experience in locating leaks. To facilitate these changes, a control panel will be required to control the leak system.

2020 SB1371 Compliance Plan
CHAPTER 10: Training Facility Enhancements

In addition to facilitate the performance focused training programs discussed in Chapter 9, SoCalGas proposes creating a learning lab in the Pico Rivera Training Center. This Learning Lab shall include resources, reference materials, study carrels, 10 computers, 10 virtual reality googles and a printer. The key driver for this project is to facilitate self-paced, modular, eLearning.

Project Milestones

- Develop a Leak System training requirements document: Estimated 1 month
- Create design plans for leak system: Estimated 1 month
- Develop Request for Proposals: Estimated 4 months
- Contractor selection process: Estimated 5 months
- Contractor Construction time: Estimated 8 months
- Situation City modifications to leak detection training system: Estimated 12 months

Part 3. Abatement Estimates

While this activity supports emission reduction efforts, there is insufficient data to calculate emissions reductions for this measure.

Part 4. Cost Estimates

Capital Cost Estimates					
Activity	2021		2022		Total Loaded Capital Costs with Contingency
	Direct	Loaded	Direct	Loaded	
Situation City Enhancements	\$776,250	\$781,560	\$248,750	\$250,400	\$1,135,156
Learning Lab	\$300,000	\$302,208	\$0	\$0	\$332,428

Total Revenue Requirement over expected life of investment: \$3.1 million
Average Annual Revenue Requirement: \$144,160

Cost Assumptions

- 3 FTEs for analysis, design, and monitoring
- Contractor Construction

Part 5. Cost Effectiveness/Benefits

There is insufficient data to quantify emissions reductions from this activity. Therefore, cost effectiveness cannot be generated.

Part 6. Supplemental Information/Documentation

N/A

2020 SB1371 Compliance Plan
CHAPTER 11: Blowdown Reduction Projects at Storage

Part 1. Evaluate the Current Practice Addressed in the Chapter

This Chapter addresses the following Best Practice:

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.

In the 2018 Compliance Plan, SoCalGas was approved for funding to continue storage emission reduction efforts. In 2018 and 2019, SoCalGas implemented over 15 storage projects that reduced emissions from storage operations. These projects included but were not limited to the modification/removal of orifice meters, replacement of chemical injection pumps with ventless types, reduction of wellhead venting and gas blowdown studies.

To support these efforts, SoCalGas staffed a Project Manager to support emission reduction projects at storage fields.

In addition to capital facility enhancements to reduce emissions, several Gas Standards were updated to reduce blowdown as outlined in Chapter 2.

Emission Reductions Achieved

Due to the complexities of storage facilities, SoCalGas was unable to forecast emission reductions in the 2018 Compliance Plan. The Underground Storage Blowdown Emissions reported as the baseline in 2015 were 112,076 MCF¹. Underground Storage Blowdown Emissions reported in the calendar year 2018 were 43,481 MCF², with an estimated reduction of 68,595 MCF. The following is a table summarizing these estimated reductions.

2020 SB1371 Compliance Plan
CHAPTER 11: Blowdown Reduction Projects at Storage

System Category	2015 Emissions (MCF)	2018 Emissions (MCF)	2018 Emission Reduction (MCF)
Storage Leaks and Emissions	3,146	2,637	509
Underground Storage Compressor Emissions	84,609	9,641	74,968
Underground Storage Blowdowns	10,812	3,933	6,879
Underground Storage Component Emissions	N/A	5,281	(5,281)
Underground Storage Component Leaks	107	21,989	(21,882)
Dehydrator Vent Emissions	13,402	0	13,402
Total	112,076	43,481	68,595

Cost Effectiveness Evaluation on Historic Work

Cost effectiveness cannot be calculated at this time due to insufficient data.

Part 2. Proposed New or Continuing Measure

SoCalGas requests funding to continue to reduce emissions in storage operations. SoCalGas has identified several projects for its storage facilities that will achieve emission reductions during normal storage operations and will continue to explore opportunities for emission reduction.

Although new projects may be identified during the Compliance period, the following projects have been identified for storage operations during this Compliance period:

- Install blowdown system on condensing compressors (Estimated Q1 2021)
- Replace reciprocating vapor recovery units with screw compressors (Estimated Q4 2022)
- Convert main plant emergency shutdown valves from gas-powered to air-powered (Estimated Q4 2022)
- Performing preventative maintenance for relief valves (Continuous)
- Repair above ground leaks associated with increased leak survey (Continuous)
- Method 21 leak detection training (Continuous)
- Replace actuated valves from gas-powered to air-powered (Estimated Q4 2022)
- Replace intermittent bleed devices (Continuous)

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

2020 SB1371 Compliance Plan
CHAPTER 11: Blowdown Reduction Projects at Storage

Part 3. Abatement Estimates

There is insufficient data to forecast emission reductions for these activities.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost
	Direct	Loaded	Direct	Loaded	
Storage Emission Reduction Projects	\$500,000	\$616,450	\$500,000	\$616,450	\$1,446,768
Project Manager - Storage	\$20,000	\$41,172	\$20,000	\$41,172	

Capital Cost Estimates					
Activity	2021		2022		Total Loaded Capital Cost
	Direct	Loaded	Direct	Loaded	
Storage Emission Reduction Projects	\$5,000,000	\$6,264,500	\$5,000,000	\$6,264,500	\$13,781,900

Total Revenue Requirement over expected life of investment: \$41.3 million

Average Annual Revenue Requirement: \$1.7 million

Cost Assumptions

- Project Manager annual cost of \$100K (20% charged to O&M, 80% charged to capital projects)
- Project costs were determined using historical cost data from 2019
- 10% contingency is included in the total O&M and Capital cost

Part 5. Cost Effectiveness/Benefits

There insufficient data to calculate cost effectiveness for these activities.

Part 6. Supplemental Information/Documentation

Attachment N: Storage Operations Project Schedule 2018-2020

2020 SB1371 Compliance Plan
CHAPTER 12: Stationary Methane Detectors

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

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.

SoCalGas is conducting a phased implementation of stationary methane detection technologies at company facilities from 2018-2020. This activity explores a range of alternative monitoring technologies to assess their accuracy, propensity to generate false alarms, and ongoing cost of maintenance and calibration.*

This phased implementation allows SoCalGas to compare the effectiveness of both infrared point sensors that reports methane concentration at a specific location and tunable diode laser technology. A tunable diode laser measures gas concentration based on how much of a laser's intensity is absorbed along its path. The laser's wavelength can be set to measure a specific gas, such as methane. For comparative purposes, both technologies are being deployed at selected facilities. SoCalGas targeted installing ten (10) Above Ground Meter and Regulating stations. All 10 sites are operating stations so the data gathered would be representative of real-world conditions.

The point sensors are mounted near potential leak points while the tunable diode lasers are positioned as closely as possible to the location's primary equipment. Each tunable diode unit allows for two independent monitoring paths. The paths are constructed to run on opposing sides of the equipment to allow for variances in wind direction. SoCalGas is including 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 installation at each site also includes the deployment of a meteorological monitoring station. The stations capture on-site weather measurements including wind speed, wind direction, ambient temperature, and ambient pressure.

Emission Reductions Achieved

There is insufficient data to calculate emissions reductions achieved by this measure at this time.

Cost Effectiveness Evaluation

There is insufficient data to calculate cost effectiveness from these activities.

**CARB also requires storage facilities implement a monitoring plan effective August 6, 2019. The monitoring plan includes ambient methane monitoring, wellhead leak detection monitoring and optical gas imaging of a well blowout.*

2020 SB1371 Compliance Plan
CHAPTER 12: Stationary Methane Detectors

Part 2. Proposed New or Continuing Measure

The current two-year implementation is expected to be completed in 2020 and should provide a structured evaluation of both the technologies deployed and the emission profiles of the selected stations. For the 2021-2022 period, SoCalGas proposes to begin a second phase of implementation. SoCalGas proposes installing methane detection at approximately 10 additional company facilities, leveraging the lessons learned from the current phase and expanding the variety of facilities being monitored.

SoCalGas proposes the selection of sites with varying factors, such as limited space for new equipment, multifaceted emission profiles, and larger total site footprint. Addressing these variables will be a key factor in further expanding the volume of monitoring sites. Specifically, SoCalGas recommends the inclusion of multiple pressure limiting stations in this Compliance Plan to allow further analysis and data collection.

Project Milestones

- Confirm selection of evaluation facilities and applicable monitoring technology: Estimated Months 1-3
- Order and receive sensors and construction materials: Estimated Months 4-6
- Construction and Commissioning at evaluation facilities: Estimated Months 7-13
- Monitoring and Operations of the facilities: Estimated Months 14-22
- Assemble report-out and recommendations: Estimated Months 22-24

Part 3. Abatement Estimates

There is insufficient data to calculate emissions reduction for this activity.

2020 SB1371 Compliance Plan
CHAPTER 12: Stationary Methane Detectors

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Costs with Contingency
	Direct	Loaded	Direct	Loaded	
Labor	\$30,668	\$49,376	\$202,752	\$278,058	\$360,177
Materials	\$0	\$0	\$0	\$0	\$0
Monitoring and Analysis	\$41,140	\$81,912	\$164,560	\$327,647	\$450,514

Capital Cost Estimates					
Activity	2021		2022		Total Loaded Capital Costs with Contingency
	Direct	Loaded	Direct	Loaded	
Labor	\$1,537,316	\$1,560,252	\$413,820	\$427,873	\$2,186,937
Materials	\$2,068,000	\$2,080,402	\$22,000	\$22,933	\$2,313,668

Total Revenue Requirement over expected life of investment: \$10.1 million

Average Annual Revenue Requirement: \$637,414

Part 5. Cost Effectiveness/Benefits

There is insufficient data to calculate cost effectiveness from these activities.

Part 6. Supplemental Information/Documentation

Attachment O: Historic Project Schedule for Stationary Methane Sensor Project

Attachment P: Presentation of Stationary Methane Sensor Project

2020 SB1371 Compliance Plan
CHAPTER 13: Electronic Leak Survey

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

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 in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

SoCalGas is developing a mobile application for the Electronic Leak Survey process. Leak surveyors will carry iPads loaded with a mobile application to use GIS-generated leak survey routes instead of paper maps. Leak survey instrumentation will be used to track leaks, and leak data will be electronically uploaded into GIS. Bread crumb (GIS Location) data will be collected for the survey path walked.

Requirements gathering and vendor selection for mobile application were completed in 2018. System design activities were completed in 2019 and development of mobile application and supporting portal applications are expected to be completed in 2020. Required hardware (iPad mini, accessories, storage) and support software has been acquired. Team conducted system integration testing to validate integration paths and end to end functionality. Field demos of mobile application and portal applications were conducted in 2019 to review ease of use and gather feedback. User acceptance testing will be performed in Q1 2020. Application rollout to initial districts will start in Q2 2020 and deployment activities for all distribution districts will start in Q3 2020.

A change management team has started engaging stakeholders to provide information on the mobile application through Digi Boards, district locations, intranet articles and district visits.

Emission Reductions Achieved and Cost Effectiveness Evaluation

There is insufficient data to calculate emissions reductions and cost effectiveness for these activities.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes further developing the Electronic Leak Survey mobile application and implementing new and emerging technology. The scope of the current solution is defined based on requirements that were identified in initial requirement gathering sessions with stakeholders.

2020 SB1371 Compliance Plan
CHAPTER 13: Electronic Leak Survey

There is an expectation that new enhancement requests will become apparent as the solution is deployed and employees begin utilizing it in the field. Software packages will go through upgrade cycle and the underlying product will be upgraded by a vendor to provide additional functionality and stability. After the deployment cycle is complete, SoCalGas plans to consolidate all outstanding items that include issues that arose during deployment/training, additional requirements and enhancement requests.

SoCalGas requests funding for five Contractors to assist with the following areas:

- Assessment
- Development
- Deployment and Support
- Change management
- Training activities

The Gas Standards regarding leak survey procedures will need to be updated to reflect the new processes when they are in place.

Project Milestones

- Q1-Q2 2021 – Assessment: Team will consolidate outstanding defects, issues, requirements and determine scope/technology potential solutions. Estimated 4-5 months
- Q2 2021- Q3 2022 – Design and Development: Estimated 12-14 months
- Q3 2022 – Pilot/Test release of application to streamline for deployment: Estimated 2-3 months
- Q4 2022 – Training and Deployment in Q4 2022: Estimated 6 months

Part 3. Abatement Estimates

There is insufficient data to calculate emission reductions for this activity.

2020 SB1371 Compliance Plan
CHAPTER 13: Electronic Leak Survey

Part 4. Cost Estimates

O&M Cost Estimates					
	2021		2022		Total Loaded O& M Costs with Contingency
Activity	Direct	Loaded	Direct	Loaded	
Further Develop Electronic Leak Survey Application	\$318,500	\$320,379	\$109,200	\$109,844	\$473,245

Capital Cost Estimates					
	2021		2022		Total Loaded Capital Costs with Contingency
Activity	Direct	Loaded	Direct	Loaded	
Further Develop Electronic Leak Survey Application	\$4,088,266	\$4,112,387	\$3,500,406	\$3,521,058	8,396,790

Total Revenue Requirement over expected life of investment: \$11.7 million

Average Annual Revenue Requirement: \$2.1 million

Cost Assumptions

- \$2M Software purchases – Vendor software license and upgrades
- \$1.2M Hardware upgrades
- \$4.8M Labor (contractors + internal resources)
- \$500K Training

Part 5. Cost Effectiveness/Benefits

There is insufficient data to calculate the cost effectiveness for these activities.

Part 6. Supplemental Information/Documentation

Attachment Q: Historic Project Schedule for Electronic Leak Survey

Attachment R: Presentation of Electronic Leak Survey

2020 SB1371 Compliance Plan
CHAPTER 14: Aerial Monitoring

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practices:

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 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 agreement on a similar methodology to improve emissions quantification of leaks to assist in the demonstration of actual emissions reductions.
Best Practice 21: Find It, Fix It
Utilities shall repair leaks as soon as reasonably possible after discovery, but in no event, no 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.

As discussed in Chapter 2, leak survey on distribution lines has historically been performed according to the requirements in 49 CFR 192.723 to ensure safety. SoCalGas pipelines are typically leak surveyed at intervals of one, three, or five 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. Survey is typically performed by walking over the pipeline and using handheld infrared methane detection tools, or by driving over the pipeline using optical methane detection. While these tools can find pipeline leaks, they do not have the capability to detect the leak flux rate, referred to as leak quantification in this Chapter.

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CHAPTER 14: Aerial Monitoring

In 2018, SoCalGas began surveying all Pre-1986 Aldyl-A pipe annually. In the 2018 Compliance Plan, SoCalGas was approved to move unprotected steel pipe from three-year to one-year leak survey cycles, which began in January 2020. In Chapter 29 of this Compliance Plan, SoCalGas is further proposing to increase survey frequency on post-86 plastic pipe and protected steel pipe from five years to three years.

In addition to increased leak survey, SoCalGas began implementing a large leak prioritization program to quantify emissions from leaks and prioritize large leaks for repair, as discussed in Chapter 4. Prior to the development of the large leak prioritization program, most leak quantification work was performed as part of RD&D and was not implemented as part of a routine leak survey.

In 2019, SoCalGas performed a RD&D evaluation of a LiDAR aerial leak detection and quantification technology. The evaluation included flying over 12 square miles of SoCalGas' service territory, inspecting 278 miles of main, 24,640 services, and 28,692 meters for leaks. The findings from the initial RD&D evaluation were very positive and will be expanded in 2020. The work completed to date indicates that a full implementation will result in cost-effective emission reductions.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to enhance its leak survey program by implementing an aerial leak survey and leak quantification program. Aerial survey will be performed using LiDAR technology mounted to a helicopter and would be performed on pipeline that is not scheduled for routine survey in the year of interest. This is an incremental survey of approximately 19,377 miles of pipe per year, assuming the proposal to increase survey frequency as proposed in Chapter 29 is approved.

Incremental aerial survey and quantification is expected to begin in 2021. Between this aerial survey, the increased survey proposed in Chapter 29, and the ongoing incremental survey discussed in Chapter 2, all SoCalGas pipelines will be inspected for leaks annually at a minimum.

Project Milestones

- Secure vendor contract (Estimated Q3 2020)
- Determine scope of work (Estimated Q4 2020)
- Update leak survey maps (Estimated Q4 2020)
- Begin performing aerial survey (Estimated Q1 2021)

2020 SB1371 Compliance Plan
CHAPTER 14: Aerial Monitoring

Part 3. Abatement Estimates

SoCalGas estimates that the emission reductions achieved by performing aerial survey will be 76,834 MCF per year. This include 18,768 MCF reduced from SoCalGas’ system and 58,066 MCF reduced from leaks found downstream of the meter.

This estimate was generated by making the following assumptions:

SoCalGas expects to find 1,889 leaks in its system each year. This assumption is based on historical leak findings and the aerial survey evaluation conducted by SoCalGas, which demonstrated LiDAR aerial survey will be able to detect the top 5% of largest leaks. The average emissions for leaks detected are estimated to be 4.303 CFH. This assumption is based on data collected from actual SoCalGas system leaks through multiple leak measurement studies.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Aerial leak survey	\$5,400,000	\$5,431,860	\$5,400,000	\$5,431,860	\$14,214,552
Data analysis and leak response	\$500,000	\$1,029,300	\$500,000	\$1,029,300	

Total Revenue Requirement over expected life of investment: \$15 million

Average Annual Revenue Requirement: \$7.5 million

Cost Assumptions

Vendor costs for aerial survey are based on preliminary numbers, contract has not been generated with a fixed cost for the proposed scope of work. Actual costs may differ at the time of contract.

The cost estimate for data analysis and leak response is based on high level assumptions. The initial technology evaluation was concluded in January 2020; therefore, there has not been enough time to thoroughly evaluate the costs for implementing system changes to operationalize this measure. Actual costs may vary as more information becomes available.

2020 SB1371 Compliance Plan
CHAPTER 14: Aerial Monitoring

Part 5. Cost Effectiveness/Benefits

Standard Cost Effectiveness Calculation:
\$97.55/MCF

Cost Effectiveness avoided Cap & Trade costs:
\$94.83/MCF

Cost Effectiveness with the avoided Social Cost of Methane:
\$90.63/MCF

Part 6. Supplemental Information/Documentation

Attachment S: Technical specifications for Bridger Photonics LiDAR Technology

Attachment T: Aerial Survey Emission Reduction Estimates

2020 SB1371 Compliance Plan
CHAPTER 15: Damage Prevention Public Awareness

Part 1. Evaluate the Current Practices addressed in this Chapter

This Chapter addresses the following Best Practices:

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.

SoCalGas has 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 per Cal. Gov’t Code § 4216.2. The public awareness program is driven by (1) the requirements of 49 C.F.R. § 192.61f, the technical document, (2) Public Awareness Programs for Pipeline Operators, API RP 1162 and (3) program expansion recommendations by regulators.

In the 2018 Compliance Plan, SoCalGas requested and was approved to expand the public awareness program and staff. SoCalGas implemented the following activities to support these efforts:

- *Homeowner Focus groups* – residential focus groups were conducted to identify and explore current understanding of dig-in protocol, motivations and barriers for following dig-in procedures, and message improvements/opportunities. Two focus groups were completed.
- *Paradigm Excavator Outreach Meetings* – participation at contractor liaison meetings where pipeline operator can exchange pipeline safety information with local emergency/public officials and excavators. Participated at eight (8) liaison meetings.
- *National Excavator Initiative* - initiative support of a broad-based damage prevention effort that raises the awareness of underground infrastructure; increase the 811 system; and encourages stakeholders to take additional safety steps after the 811 call is made in order to protect themselves and the infrastructure.

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CHAPTER 15: Damage Prevention Public Awareness

- *Damage Prevention at K-5 Schools* – pilot program of natural gas pipeline public safety awareness outreach program targeting K-6 educators, students, and families in 25 high dig-in zip codes.
- *Next Door App* - 2-month campaign ran in top 60 dig-in zip codes with an estimated impression of 900,079.
- *National Safe Digging Month* - Los Angeles Angels partnership to get pipeline safety messages to the public during the month of April, National Safe Digging Month, which included radio spots on Angels Radio, in-stadium SoCalGas dig-safe commercials and booth space.
- *Long Beach Grand Prix* - partnership to get pipeline safety messages to the general public during the Grand Prix, which is in April, National Safe Digging Month.
- *811 Day Campaign* – campaign consisted of bus ads (estimated impressions 107,819,504), digital freeway ads and in-cinema safety video run (estimated impressions of 1,393,119) for 2-4 weeks around the time of 811 Day.
- *Ventura County Fair* – booth space to get pipeline safety messages to the general public.
- *Pipeline Association for Public Awareness (PAPA) supplemental mailers* – provided additional pipeline safety mailers from PAPA’s program to excavators, public officials, emergency responders in service territory.
- *Home Depot/Lowes Initiative* – pilot program to get safe digging messaging on tear-off sheets in the gardening, shovel, piping sections of Home Depot, Lowes and at plumbing/contractor supply stores. Approximately 175 stores participating with potential to add additional 150.
- *Continuous analysis of near-miss data, dig-ins, Claims repeat offenders* – monitoring of data to track and trend in order to determine changes needed to improve and increase public awareness communications and outreach tactics.

Emissions Reduction and Cost Effectiveness Evaluation on Historic Work

There is insufficient data to evaluate emission reductions or cost effectiveness for historical work at this time.

2020 SB1371 Compliance Plan
CHAPTER 15: Damage Prevention Public Awareness

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to continue conducting incremental outreach and education to the general public, contractors, and excavators, mailing safe digging procedures to contractors, and maintaining the incremental FTE hired to support the public awareness program. Continued activities to support this measure include but are not limited to:

- Analyze excavation damage data and cause of incidents, utilize this information 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; use data and analysis to develop strategies to increase effectiveness for continuous improvement plans.
- Conduct focus groups and refine messaging and strategies based on findings.
- Work with other departments to analyze repeat offender data and develop strategies to reduce damages.
- Be a point of contact for assisting with education services for pipeline and public awareness programs or concerns.

As shown in SoCalGas' 2018 Compliance Plan, trending 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 should result in decreased damages, and therefore, lower emissions.

SoCalGas proposes to increase 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) employees. 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

Emissions reductions cannot be calculated for this measure, as the efforts overlap with Chapter 5. Please refer to Chapter 5 for the emissions reduction estimates forecasted for damage prevention activities.

2020 SB1371 Compliance Plan
CHAPTER 15: Damage Prevention Public Awareness

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Labor	\$240,000	\$494,064	\$240,000	\$494,064	\$2,821,122
Public Awareness Marketing Materials	\$783,640	\$788,264	\$783,640	\$788,264	

Total Revenue Requirement over expected life of investment: \$3 million

Average Annual Revenue Requirement: \$1.5 million

Cost Assumptions

- 2 FTEs (An Advisor and a Project Manager) at \$120,000 per year
- Marketing material includes production and distribution of mailers, pamphlets, brochures, key chains and additional materials for customers to bring awareness. Cost estimates based on historical implementations.

Part 5. Cost Effectiveness/Benefits

There is insufficient work to evaluate the cost effectiveness of these activities.

Part 6. Supplemental Information/Documentation

Attachment U: Line Item Cost Breakdown

Attachment V: Historic Project Schedule for Damage Prevention

2020 SB1371 Compliance Plan
CHAPTER 16: Pipe Fitting Specifications

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

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

SoCalGas has a supply management department that works with vendors to ensure purchased materials meet SoCalGas material specifications (MSP) requirements for all components. When materials are received, samples are inspected at a warehouse facility to verify requirements are met. 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 to begin contract negotiations with alternative vendors to confirm all concerns are addressed.

SoCalGas hired a third-party consultant in 2019 to review company Material Specifications (MSP) and to identify consistent requirements across component categories. Results from the investigation will guide future improvement efforts.

Emission Reductions Achieved

There is insufficient data to estimate emission reductions for these activities.

Part 2. Proposed New or Continuing Measure

SoCalGas will continue to improve inspection of threaded components to improve MSP compliance of threaded fittings. SoCalGas proposes to expand the Quality Control (QC) team by expanding the role and competencies of the QC Inspectors. SoCalGas proposes four new QC FTE's to improve the review processes going forward. These employees will be tasked with improving test setups and testing efficiency. They will also work with MSP owners to verify that the checks being performed on the materials are adequate.

SoCalGas will continue to work with component manufacturers to align gauging practices and developing process controls to maintain high material thread quality standards. Upon conclusion of the third-party review of the company MSP and QC process, SoCalGas will revise the MSPs, if necessary, to create consistent requirements across component categories. SoCalGas will continue to evaluate additional feasible solutions based on results of material QC analysis.

2020 SB1371 Compliance Plan
CHAPTER 16: Pipe Fitting Specifications

Project Milestones

- Hire and train incremental employees: Estimated 9 months
- Implement Quality Control inspection process: Estimated 9 months
- Update material specs, if necessary: Estimated 18 months

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions from the activities.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Costs with Contingency
	Direct	Loaded	Direct	Loaded	
Implementation of Recommendations	\$100,000	\$205,860	\$100,000	\$205,860	\$2,264,460
Labor for 4 QC employees	\$400,000	\$823,440	\$400,000	\$823,440	

Total Revenue Requirement over expected life of investment: \$2.4 million

Average Annual Revenue Requirement: \$1.2 million

Cost Assumptions

- Four Quality Control Employees at \$100,000/year/employee
- Implement QC Process improvements at \$100,000/year

Part 5. Cost Effectiveness/Benefits

There is insufficient data to calculate cost effectiveness from the activities.

Part 6. Supplemental Information/Documentation

Attachment W: Historic Project Schedule for Pipe Fitting Specifications

2020 SB1371 Compliance Plan
Chapter 17: Repeat Offenders IT Systems

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

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.

SoCalGas has a federally-mandated Public Awareness program, as prescribed in 49 CFR 192.616, and Damage Prevention Program 49 CFR192.614 which contribute to enhanced public safety by providing risk mitigation measures. When excavators generate a ticket through Underground Service Alert, locate and mark employees identify lines in the area and if a high-pressure line within ten feet is identified, an observer is assigned to monitor the excavation. Data shows that the more Underground Service Alert is used, the fewer damages occur.

Damage information is entered by hand into a form by the employee(s) dispatched to repair the damaged property. The information from this form is then manually transferred into the Company Property Damage Report System and that information is used by Claims to generate a bill for cost recovery, if applicable. SoCalGas operates three separate data systems that store line damage information. One system is the Incident Management System operated by the Dispatch department, one system is SAP which is for labor and asset management, and the other is the Company Property Damage Report System, which is operated by the Claims department. These systems currently do not have any synergy, which can generate challenges when reporting and requires employees to enter the same information three different times and three different ways.

In the past, SoCalGas used a paper form of the Company Property Damage Report System to track repeat offenders, and any offender with more than two damages in the previous quarter will be added to a list that is provided on a quarterly basis to the CPUC. However, this process does not account for the fact that repeat offenders may have a multi-year history of damaging facilities, not only on SoCalGas lines but on other utilities' lines.

As a result, SoCalGas plans to complete the process of digitizing the Company Property Damage Report towards the end of 2020. Thereafter, transition to mobile platforms to capture damages to better perform analytics, to put in place preventative measures to mitigate damages. SoCalGas plans to develop integration between enterprise systems to transmit and store new data to be captured via new mobile forms. This system will enable analyzing damage history holistically and identifying repeat offenders more readily and accurately to enhance reporting capabilities.

Emission Reductions Achieved

There is insufficient data to calculate emission reductions or cost effectiveness.

2020 SB1371 Compliance Plan
Chapter 17: Repeat Offenders IT Systems

Part 2. Proposed New or Continuing Measure

SoCalGas is proposing to complete, maintain, and enhance the digitized form and mobile platforms. SoCalGas will also continue reviewing the business structure to facilitate the proper flow and functionality of the relevant digital forms.

Project Milestones

- Complete implementation of initial project scope: Estimated by Q1 2021
- Maintaining and enhancing the digitized form and mobile platforms: Continuous

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions from these activities.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost With Contingency
	Direct	Loaded	Direct	Loaded	
Operational & Maintenance	\$337,643	\$695,072	\$337,643	\$695,072	\$1,565,390
Training	\$16,000	\$32,938	\$0	\$0	

Capital Cost Estimates					
Activity	2021		2022		Total Loaded Capital Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Mobile developments, possible integration with other systems, reporting, and analytics	\$38,400	\$40,028	\$0	\$0	\$44,031

Total Revenue Requirement over expected life of investment: \$1.8 million

Average Annual Revenue Requirement: \$860,204

Cost Assumptions

- 2 Incremental FTEs for operations & maintenance
- 1.6 existing FTEs for operations & maintenance
- Training
- IT development, integration, and changes
- Reporting and analytics

2020 SB1371 Compliance Plan
Chapter 17: Repeat Offenders IT Systems

Part 5. Cost Effectiveness/Benefits

There is insufficient data to calculate emission reductions.

Part 6. Supplemental Information/Documentation

Attachment X: Historic Project Schedule for Repeat Offender System

2020 SB1371 Compliance Plan
Chapter 18: Meter Calibration Factor

Part 1. Evaluate the Current Practices addressed in this Chapter

This Chapter addresses the following Best Practice:

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.

Historically, if a meter was outside of its calibration tolerance limits, that meter would be replaced as a Planned Meter Change (PMC). The number of meters that require replacement varies, but SoCalGas data indicated the need to replace approximately 74,000 small meters annually over years 2018-2021 due to calibration tolerance. Associated emissions are roughly one (1) CF per small meter replacement.

The following milestones were accomplished during the 2018-2020 Compliance Period:

- SoCalGas filed an Advice Letter requesting regulatory approval to update policies regarding meter replacement. Approval on Advice Letter No. 5403 was received on December 19, 2019.
- SoCalGas completed requirements, design, and build phases for updates to the billing system.
- SoCalGas is in the test phase of the new system and will complete necessary process and procedure updates.

Emission Reductions and Cost Effectiveness Evaluation

Emission reductions and cost effectiveness cannot be evaluated at this time as implementation has not yet been completed.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes continuing with ongoing maintenance using a billing calibration factor instead of meter replacement.

Project Milestones

There are no milestones for this activity; only ongoing maintenance of the activity.

Part 3. Abatement Estimates

Abatement estimates are approximately 74 MCF per year.
74,000 small meters at approximately 1 SCF per year per meter change

2020 SB1371 Compliance Plan
Chapter 18: Meter Calibration Factor

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Application Manager	\$16,000	\$32,938	\$0	\$0	\$36,232

Total Revenue Requirement over expected life of investment: \$38,589

Average Annual Revenue Requirement: \$19,295

Cost Assumptions

- An Application Manager is needed to maintain this measure.
- 65% of their time will be required for 4 months in 2021.

Cost Benefits

- Cost savings for avoided meter changes through 2022: \$34,129,971

Part 5. Cost Effectiveness/Benefits

The cost benefits of this project (approximately \$34,000,000) are significantly larger than the cost of this project (approximately \$36,000). Therefore, the cost effectiveness is a negative number, meaning that the costs of this project will ultimately be recovered by the operational benefits gained.

Part 6. Supplemental Information/Documentation

Attachment Y: Historic Project Schedule for Meter Calibration

2020 SB1371 Compliance Plan
CHAPTER 19: Enhanced Methane Detection

Part 1. Evaluate the Current Practices addressed in this Chapter

This Chapter addresses the following Best Practice:

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.

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

SoCalGas worked in 2019 to expand the capacity of the EAC to respond to requests from Operations for leak speciation where methane source is in question. The lower detection limits of new advanced leak detection instrumentation, in addition to the increased level of leak survey activities being driven by SB1371, require an expansion of these resources. SoCalGas hired an additional employee and purchased additional gas speciation tools in 2019 to support the increase of gas speciation work.

Since the 2018 Compliance Plan was approved in October 2018, all milestones have been met. The van, tools, and equipment were purchased and will be delivered and installed in 2020. The van is expected to be operational in Q3 2020.

Emissions Reduction and Cost Effectiveness Evaluation

There is insufficient data to calculate emissions reductions and cost effectiveness for this activity.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes continuing to fund the incremental lab technician, hired as part of the 2018 Compliance Plan, to continue to maintain the expanded capacity of the EAC to respond to requests from Operations for leak speciation where methane source is in question. The lower detection limits of new advanced leak detection instrumentation plus increased level of leak survey activities being driven by SB1371 requires SoCalGas to maintain the expansion of these resources.

Project Milestones

No new milestones are proposed. This is an ongoing effort.

2020 SB1371 Compliance Plan
CHAPTER 19: Enhanced Methane Detection

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions for this activity.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Technician	\$100,000	\$205,860	\$100,000	\$205,860	\$452,892

Total Revenue Requirement over expected life of investment: \$490,021

Average Annual Revenue Requirement: \$245,011

Cost Assumptions

- 1 employee at \$100,000 a year

Part 5. Cost Effectiveness/Benefits

There is insufficient data to determine cost-effectiveness for this measure.

Part 6. Supplemental Information/Documentation

Attachment Z: Historic Project Schedule for Enhanced Methane Detection

2020 SB1371 Compliance Plan
CHAPTER 20: Public Leak Maps

Part 1. Evaluate the Current Practices Addressed in this Chapter

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 in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census tract.

In 2015, SoCalGas developed and published publicly available geographic maps of nonhazardous leaks. SoCalGas updates these maps monthly with the locations where methane has been detected. The maps also provide details regarding repair scheduling and leak status. The website address for the maps is:

<https://www.socalgas.com/stay-safe/methane-emissions/methane-emissions-map>

SoCalGas did not propose any new activities related to leak mapping in the 2018 Compliance Plan.

Part 2. Proposed New or Continuing Measure

Per SED's request at the workshop that was held on October 21, 2019 in San Francisco, SoCalGas will create emission maps that will be publicly available and will provide leak summaries by zip code, as required by Best Practice 20b.

Project Milestones

- Leak map creation: Expected to be completed Q2 2021
- Updating and maintaining the customer facing website and leak maps: Continuous

Part 3. Abatement Estimates

There is insufficient data to quantify emissions reductions from this activity.

2020 SB1371 Compliance Plan
CHAPTER 20: Public Leak Maps

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Update & Maintain Website & Leak Maps	\$22,750	\$46,833	\$22,750	\$46,833	\$103,033

Total Revenue Requirement over expected life of investment: \$111,300

Average Annual Revenue Requirement: \$55,650

Cost Assumptions

- 1 existing FTE for Operations & Maintenance

Part 5. Cost Effectiveness/Benefits

There is insufficient data to quantify emissions reductions from this activity. Therefore, cost effectiveness cannot be generated.

Part 6. Supplemental Information/Documentation

Not applicable.

2020 SB1371 Compliance Plan
CHAPTER 21: Greenhouse Gas Policy Update

Part 1. Evaluate the Current Practices addressed in this Chapter

This Chapter addresses the following Best Practice:

Best Practice 2: Methane GHG Policy
Written company policy stating that methane is a potent Green House Gas (GHG) that must be prevented from escaping to the atmosphere. Include reference to SB 1371 and SB 1383.

SoCalGas updated their Environmental Excellence on January 16, 2019, in accordance with the requirements of Best Practice 2. The updated Environmental Excellent Policy is provided as Attachment AA.

There were no costs associated with this measure.

Part 2. Proposed New or Continuing Measure

No further work is proposed.

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions for this activity.

Part 4. Cost Estimates

SoCalGas is not proposing additional activities for this measure.

Part 5: Cost Effectiveness/Benefits

There is insufficient data to estimate cost effectiveness for this activity.

Part 6: Supplement Information/Documentation

Attachment AA: Updated SoCalGas Environmental Excellence Policy

2020 SB1371 Compliance Plan
CHAPTER 22: Vapor Collection Systems

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

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.

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. Construction for one vapor recovery system is in progress and is expected to be completed in Q2 2020.

No incremental staffing was required to implement this measure.

Cost Effectiveness Evaluation on Historic Work

The vapor recovery system will be completed in 2020 so no emission reductions have been achieved yet, however upon completion, emissions reduction is forecasted to be 12,614 MCF per year.

Piston rod packing systems are used to maintain a tight seal around piston rods within compressor engines. These packing systems have tendency to leak and cause methane to be emitted. This estimate is based on a leak rate of 2 cubic feet per minute (CFM) per packing system which are assumed to be running 100% all year. There are six (6) packings per compressing engine and two (2) compressor engines found in the Blythe Compressor Station. The vapor recovery system will reduce emissions on these packing systems and that emission reduction is calculated below:

$$2 \text{ CF/min} \times 525,600 \text{ min/year} \times 6 \text{ packings/engine} \times 2 \text{ engines/plant} = 12,614,400 \text{ CF/year} \\ = 12,614 \text{ MCF/year}$$

These emissions will be reduced from the Compressor Emissions Source Category within the Transmission Compressor Stations System Appendix.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to monitor the vapor collection system installation over this Compliance period to collect actual emission reduction data and information regarding operations and maintenance cost of the system. SoCalGas proposes evaluating cost effectiveness over this Compliance period before proceeding with additional implementations because vapor collection systems are a new implementation, they have high costs associated with them and emission estimates are based on models.

2020 SB1371 Compliance Plan
CHAPTER 22: Vapor Collection Systems

Part 3. Abatement Estimates

Once the vapor recovery system is completed forecasted emissions reduction is estimated to be 12,614 MCF per year. Piston rod packing systems are used to maintain a tight seal around piston rods within compressor engines. These packing systems have tendency to leak and cause methane to be emitted. This estimate is based on a leak rate of two (2) CFM per packing system which are assumed to be running 100% all year. There are six (6) packings per compressing engine and two (2) compressor engines found in the Blythe Compressor Station. The vapor recovery system will reduce emissions on these packing systems and that emission reduction is calculated below:

$$\begin{aligned} 2 \text{ CF/min} \times 525,600 \text{ min/year} \times 6 \text{ packings/engine} \times 2 \text{ engines/plant} &= 12,614,400 \text{ CF/year} \\ &= 12,614 \text{ MCF/year} \end{aligned}$$

These emissions will be reduced from the Compressor Emissions Source Category within the Transmission Compressor Stations System Appendix.

Part 4. Cost Estimates

SoCalGas is not requesting funding for this measure during this Compliance period.

Part 5. Cost Effectiveness/Benefits

Not applicable.

Part 6. Supplemental Information/Documentation

Attachment AB: Historic Project Schedule for Blythe Compressor Station Vapor Recovery System

2020 SB1371 Compliance Plan
CHAPTER 23: Differential Pressure Testing

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

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.

SoCalGas was previously required to perform accuracy testing on rotary meters by Resolution G-3257, which necessitated removing the meters and testing them at the meter shop. Performing this accuracy test emitted roughly five cubic feet of natural gas per test. SoCalGas proposed and was approved to switch to Differential Pressure (DP) testing, an alternative method to test for meter accuracy which has zero emissions, in the 2018 Compliance Plan. All SoCalGas rotary meters have Pete’s plugs - self-sealing plugs, which allows technicians to insert a DP connection with little to no gas escaping. With each successful DP test, SoCalGas prevents depressurization of the meter set, which avoids venting to atmosphere. As such, the emissions from the previous method are prevented by using DP testing instead.

To change SoCalGas’ testing method for rotary meters to DP testing, SoCalGas created and published new Gas Standards (Gas Standards 185.0347 and 107.0313) in 2019 to inform field personnel of the new testing method. Gas Standard 185.0347 requires that field technicians use DP for accuracy testing instead of performing accuracy testing in the meter shop and outlines the testing procedures. Gas Standard 107.0313 created Operation, Calibration, and Maintenance Procedures for the tools needed to perform DP.

In 2019, SoCalGas purchased, certified, and deployed 73 DP testing tools for use by Operations technicians and training units for the Gas Operations training classes. Additionally, a maintenance plan was created for continued accuracy of the measurement devices.

SoCalGas also created training materials and curriculum to rollout this new testing method to field personnel. To facilitate knowledge transfer, on-site training was provided at 14 locations throughout the service territory for all Meter & Regulation technician I, II, leads, Gas Operations training instructors, and their instructional designer. Approximately 125 employees were trained on the policies, procedures, and tools needed to perform DP testing.

In order to obtain a valid DP test, the customer has to consume gas at a certain rate. To address this, SoCalGas developed a Dashboard in 2019. The Dashboard allows the technician to see a customer’s usage pattern divided into average hourly consumption rates. This helps the technician to schedule site visits during an interval of time that will provide a better chance of obtaining a valid DP test.

The scope of work proposed in the 2018 Compliance Plan was completed on July 31, 2019.

2020 SB1371 Compliance Plan
CHAPTER 23: Differential Pressure Testing

Cost Effectiveness

The total expenditures for this effort were \$348,000 (fully loaded). SoCalGas estimates that about 7,500 meters will be tested using DP annually, which results in an emissions reduction of 5 MCF annually. Over 10 years (2020 – 2030), this results in a total program emissions reduction of 50 MCF. The costs associated with this project included training, change management, and tooling to perform the DP testing.

Cost Benefits

Operational Savings: \$299,507/year * 10 years = \$2,995,066

Operational savings include an estimated reduction in meter replacement costs and a reduction in labor by switching to the DP testing method. These savings assume a 5% success rate. This rate will likely increase over the decade, which will further increase the cost effectiveness of this measure.

Cost Effectiveness Through 2030

The cost benefits of this project (approximately \$3,000,000) are significantly larger than the cost of this project (\$348,000). Therefore, the cost effectiveness is a negative number, meaning that the costs of this project will ultimately be recovered by the operational benefits gained.

Part 2. Proposed New or Continuing Measure

No further work is proposed for this measure.

Part 3. Abatement Estimates

SoCalGas forecasts an annual reduction of 5 MCF.

Part 4. Cost Estimates

No additional costs are forecasted for this Compliance period.

Part 5: Cost Effectiveness/Benefits

Not applicable.

Part 6: Supplement Information/Documentation

Attachment AC: Gas Standard 185.0347

Attachment AD: Gas Standard 107.0313

Attachment ADD: Historic Project Schedule for Differential Pressure Testing

2020 SB1371 Compliance Plan
CHAPTER 24: Distribution Above Ground Leak Survey

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.

Above ground leakage surveys have historically been completed to meet the requirements of 49 CFR 192 and GO 112F, which also satisfies 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 leakage inspections are performed using soap tests and by monitoring for sight, sound, and smell.

In the 2018 Compliance Plan, SoCalGas requested and was approved for funding to provide M&R Technicians with instrumentation to begin performing and recording instrumented leakage surveys. SoCalGas has purchased the required instruments to perform instrumented inspections. SoCalGas has 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.

No incremental staffing was required to implement this measure. Training of existing M&R Technicians on the new instruments is planned to be conducted in 2020.

Emissions Reduction and Cost Effectiveness Evaluation

There is insufficient data to determine the emissions reductions and cost effectiveness achieved by this measure at this time.

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. SoCalGas is not requesting additional funding in this Compliance period.

2020 SB1371 Compliance Plan
CHAPTER 24: Distribution Above Ground Leak Survey

Part 3. Abatement Estimates

SoCalGas cannot calculate or document emissions because the emissions related to this measure are based on a population-based emission factor.

Part 4. Cost Estimates

SoCalGas is not requesting funding for this measure during this Compliance period.

Part 5. Cost Effectiveness/Benefits

Not applicable.

Part 6. Supplemental Information/Documentation

Attachment AE: RMLD Technical Specifications

Attachment AF: Gas Standard 184.0275 Inspection Schedule – Regulator Station, Power
Generating Plant Regulation Equipment Requirements

2020 SB1371 Compliance Plan
CHAPTER 25: Storage Aboveground Leak Survey

Part 1. Evaluate the Current Practices Addressed in the Chapter

This Chapter addresses the following Best Practices:

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 pressures 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.

Aboveground leak surveys at storage facilities have historically been completed to meet the requirements of 49 CFR 192 Subpart M - Maintenance and GO 112F. These surveys meet the requirement for Best Practice 19. However, most of the surveys use equipment to detect the leak, not equipment that measures the concentration of the leak to the levels required by CARB. 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. CARB Oil and Gas Rule became effective January 1, 2018 and requires quarterly leak surveys at underground storage facilities. CARB also requires storage facilities implement a monitoring plan effective August 6, 2019. The monitoring plan includes ambient methane monitoring, wellhead leak detection monitoring and optical gas imaging of a well blowout.

Aboveground storage fence-line methane sensors were installed at an underground storage facility in October 2016 to monitor atmospheric methane concentrations.

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 began accelerating leak repair.

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

Emissions Reduction and Cost Effectiveness Evaluation

There is insufficient data to determine the emissions reduction or cost effectiveness achieved by this measure because leak repairs are performed on facilities with population-based emission factors.

2020 SB1371 Compliance Plan
CHAPTER 25: Storage Aboveground Leak Survey

Part 2. Proposed New or Continuing Measure

SoCalGas requests funding to continue to perform instrumented surveys and accelerate leak repairs in Storage Operations. SoCalGas proposes to make efforts to repair all leaks sooner than required by other regulations:

DOGGR gas wells

- Methane concentration greater than 50,000 ppm and repaired in less than one day
- Methane concentration between 10,000 and 50,000 ppm and repaired in less than five days

LDAR inspected facilities

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

No additional incremental staffing is forecasted to support this measure in Storage Operations for this Compliance period.

Part 3. Abatement Estimates

SoCalGas cannot estimate emission reductions because the emissions related to this measure are estimated using population-based emission factors.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Incremental Field Employees	\$523,546	\$1,071,455	\$523,546	\$1,071,455	\$2,903,237
Incremental Supervisors	\$121,200	\$248,239	\$121,200	\$248,239	

Total Revenue Requirement over expected life of investment: \$3.1 million

Average Annual Revenue Requirement: \$1.5 million

Cost Assumptions

- Represented Employee Hourly Rate: \$41.47
- Five (5) Incremental Station Technician FTE's
- One (1) Incremental Station Supervisor
- \$100K annual salary for Supervisor
- \$1,000 annual O&M cost per FTE
- 10% contingency is included in the total O&M cost

2020 SB1371 Compliance Plan
CHAPTER 25: Storage Aboveground Leak Survey

Part 5. Cost Effectiveness/Benefits

There is insufficient data to calculate cost effectiveness for these activities.

Part 6. Supplemental Information/Documentation

Attachment AG: TVA Specifications

2020 SB1371 Compliance Plan
CHAPTER 26: Methane Emissions Training

Part 1. Evaluate the Current Practices Addressed in this Chapter

The Best Practices supported by this implementation include:

Best Practice 11: Methane Emissions Minimization Policies Training
A training program to educate workers as to why it is necessary to minimize methane emissions and abate natural gas leaks. 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.
Best Practice 12: Knowledge Continuity Training Programs
Knowledge Continuity (transfer) Training Programs provide knowledge continuity for new methane emissions reductions best practices as workers, including contractors, leave and new workers are hired. Knowledge continuity 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.

In 2018–2019, SoCalGas worked with an instructional designer to develop a training module to educate company employees as to why it is necessary to minimize methane emissions and abate natural gas leaks. The training script received approval by SED, in consultation with CARB, in 2019. SoCalGas will require training completion by all employees in 2020.

Emission Reductions Achieved

There is insufficient data to estimate emission reductions and cost effectiveness for these activities.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to provide ongoing training to maintain knowledge continuity. Future training will be for all new company employees integrated in continuity modules.

Part 3. Abatement Estimates

There is insufficient data to estimate emission reductions from these activities.

Part 4. Cost Estimates

Costs will be incorporated into base business as they are expected to be minimal. Anticipated incremental time will be needed from employees for the following activities:

- 1 hour of training for an average of 300 new employees per year
- Administration of training completion tracking

2020 SB1371 Compliance Plan
CHAPTER 26: Methane Emissions Training

Part 5. Cost Effectiveness/Benefits

There is insufficient data to calculate cost effectiveness from the activities.

Part 6. Supplemental Information/Documentation

Attachment AH: Historic Project Schedule for Implementation of Methane Emissions Training

2020 SB1371 Compliance Plan
CHAPTER 27: Distribution Above Ground Leak Repair

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 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.

In the 2018 Compliance Plan, SoCalGas was approved for funding to repair its above ground minor leak (AG Minor) inventory. In October 2018, when the Compliance Plan was approved, this inventory included roughly 5,400 AG Minor leaks. In 2019, SoCalGas repaired approximately 5,000 of these leaks. SoCalGas anticipates completing the repair of this inventory by the end of first quarter 2020.

In addition to reducing the AG Minor leak inventory, SoCalGas now requires an accelerated repair time for AG Minor leaks. Previously, Operations had the flexibility to repair AG Minor leaks when it was practical to do so. The policy was revised requiring AG Minor leaks discovered by Distribution to be classified as AG Non-Hazardous leak and to be repaired in a time frame of 10 days to 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. The updated policy can be found as Attachment AI: Updated Gas Standard 223.0126 highlighted to reflect updates regarding AG Minor repair policy.

To support these leak repair efforts, SoCalGas has been using the incremental field employees discussed in Chapters 1 and 2 to manage these repairs.

Emission Reductions Achieved

AG Minor leaks are included in population-based emission factors. Therefore, AG Minor leak repair emission reduction efforts are not being accounted for in the Annual Emissions Report.

Cost Effectiveness Evaluation on Historic Work

No cost effectiveness was forecasted for this measure in the 2018 Compliance Plan, as emissions for AG Minor leaks are part of a population-based emission factor. Program to date spend on the Distribution AG Minor leak inventory reduction is approximately \$569,000 (loaded costs).

2020 SB1371 Compliance Plan
CHAPTER 27: Distribution Above Ground Leak Repair

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to continue to repair all AG Non-Hazardous leaks ground leaks within 10 days to 6 months depending on the leak proximity to a building

Subsequent to submitting its 2018 Compliance Plan, SoCalGas has been developing a leak-based reporting method for customer meter emissions. This method of calculating meter emissions should allow SoCalGas to begin estimating emission reductions from leak detection and repair on meters, as opposed to using population-based emission calculations. This method was presented at the 2020 Winter Workshop.

Part 3. Abatement Estimates

The shortened repair time for AG Minor leaks is expected to reduce emissions by 175,000 MCF on an annual basis based on the proposed emission calculation method. However, if this method does not change, no emissions reductions will be recorded due to the use of population-based Emission Factors.

Part 4. Cost Estimates

No costs are forecasted for this activity in this Compliance period.

Part 5. Cost Effectiveness/Benefits

There is insufficient data to calculate the cost effectiveness for these activities.

Part 6. Supplemental Information/Documentation

Attachment AI: Updated Gas Standard 223.0126 highlighted to reflect updates regarding AG Minor repair timeframe

2020 SB1371 Compliance Plan
CHAPTER 28: High Bleed Device Replacement

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practice:

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.

SoCalGas has been addressing the replacement of high-bleed pneumatic devices since 1993 through the EPA Natural Gas STAR Best Practice. Pneumatic devices powered by pressurized natural gas are used widely in the natural gas industry as pressure regulators and valve controllers. Methane emissions from pneumatic devices are one of the largest sources of vented methane emissions from the natural gas industry. Reducing these emissions by replacing high-bleed devices with low-bleed devices, retrofitting high-bleed devices, and improving maintenance practices can be cost-effective. Individual savings will vary depending on the design, condition and specific operating conditions of the controller.

Pneumatic devices come in three basic designs:

1. Continuous bleed devices are used to modulate pressure and will 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.

To reduce emissions from pneumatic devices the following options can be pursued, 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. Of the 8 devices, seven (7) have already been either removed or replaced. The one remaining high bleed pneumatic device is anticipated to be removed in 2020. Replacement of this device is complex and requires coordination with a customer.

No incremental staffing was required to implement this measure.

2020 SB1371 Compliance Plan
CHAPTER 28: High Bleed Device Replacement

Emission Reductions Achieved

The estimated emission reductions achieved to date are 1,337 MCF per year. Emissions from high bleed pneumatic devices are 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 1,337 MCF reductions will not be captured in the Annual Emissions Report.

Cost Effectiveness Evaluation of Historic Work

Program to date spend on removal of high bleed devices is approximately \$637,860. This cost includes the cost of materials, internal labor and contracted labor to remove devices. However, revenue requirement cannot yet be calculated for this measure, as one device is still pending replacement in 2020. Therefore, there is insufficient data to calculate cost effectiveness for this measure.

Part 2. Proposed New or Continuing Measure

SoCalGas anticipates removing or replacing all high bleed pneumatic devices before this Compliance period. No additional work is being proposed at this time.

Part 3. Abatement Estimates

The estimated emission reductions forecasted are 1,500 MCF per year.

Part 4. Cost Estimates

SoCalGas is not requesting further funding for this measure during this Compliance period.

Part 5. Cost Effectiveness/Benefits

Not applicable.

Part 6. Supplemental Information/Documentation

Attachment AJ: High Bleed Pneumatic Devices Project Schedules

2020 SB1371 Compliance Plan
CHAPTER 29: 5-to-3 Year Leak Survey on SOTA Pipe

Part 1. Evaluate the Current Practices Addressed in this Chapter

This Chapter addresses the following Best Practices:

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 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.

Leak surveys on distribution lines have historically been performed according to the requirements in 49 CFR 192.723 for safety reasons. SoCalGas pipelines are typically leak surveyed at intervals of one, three, or five 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 Pre-1986 Aldyl-A pipe from 5-year and 3-year to annual. Then in 2019, SoCalGas increased the survey frequency for all unprotected steel pipe from 3-year to annual.

Part 2. Proposed New or Continuing Measure

SoCalGas proposes to begin three-year leak survey on protected steel and post-86 plastic pipe. Updates will need to be made to Gas Standard 223.0100 to reflect changes to leak survey frequency.

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As part of its 2018 Compliance Plan, SoCalGas evaluated emission reduction opportunities for increasing leak survey on its state of the art (SOTA) pipe, including post-86 plastic and protected steel pipe, and found the emission reductions achieved from this implementation would not be cost effective. Subsequent to submitting its 2018 Compliance Plan, SoCalGas has been developing leak-based reporting opportunities on meters. This method of calculating meter emissions will allow SoCalGas to begin estimating emission reductions from leak detection and repair on meters, as opposed to using population-based emission calculations. As a result, increasing leak survey frequency is expected to contribute to increased emission reductions and improved cost effectiveness.

These activities will require staffing 13 incremental Construction Technicians to perform leak survey, and 2 incremental Field Operations Supervisors. Updates will need to be made to leak survey maps, SAP, and GIS to monitor compliance and work scheduling. The incremental survey proposed in both the 2018 and 2020 Compliance Plans has created and will create large variations in month to month survey requirements. To address this issue, SoCalGas will survey approximately 28 million incremental feet of pipe in order to update the anniversary requirement for survey and relevel the survey maps. This will be a one-time requirement in order to maintain a level workforce throughout the year for leak survey. The levelization costs outlined in this effort also cover the levelization efforts needed by switching to annual leak survey cycles on Pre-1986 Plastic and unprotected Vintage Steel. It is most cost effective to conduct this effort for all pipe once, rather than as two separate efforts.

Project Milestones

- Hire and train 13 incremental Construction Technicians: Expected completion 6-12 months
- Hire and train 2 Incremental Survey Supervisors: Expected completion 6-12 months
- Hire and train 2 Quality Assurance FTE's: Expected completion 6-12 months

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Part 3. Abatement Estimates

SoCalGas estimates that the emission reductions achieved by increasing leak survey cycles on protected steel and post-86 plastic to three-year survey cycles will result in an emission reduction of 14,062 MCF from the 2015 baseline by 2025. The emission reductions are reflected in the table below. These emissions will be reduced from the Pipeline Leaks Emission Source Category within the Distribution Mains and Services System Category.

Scenario	Baselines Emissions (MCF)	Estimated Emission Reductions (MCF)					
		2015	2021	2022	2023	2024	2025
Year	2015	2021	2022	2023	2024	2025	2026
Post-86 Plastic Pipe from 5 Yr to 3 Yr	26,715	2,973	5,870	9,107	10,520	10,822	10,822
Protected Steel 5 Yr to 3 Yr	7,785	1,272	1,958	2,733	3,122	3,240	3,240f

SoCalGas also forecasts a potential emission reduction due to the increased leak survey of the meters on these pipelines. This is discussed in Chapter 27.

Part 4. Cost Estimates

O&M Cost Estimates					
Activity	2021		2022		Total Loaded O&M Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Incremental Leak Survey Field Employees	\$1,289,159	\$2,609,518	\$1,289,159	\$2,609,518	\$9,762,138
Incremental Leak Survey Supervisors	\$242,400	\$500,055	\$242,400	\$500,055	
System Updates	\$82,935	\$170,730	\$0	\$0	
Map Levelization Survey	\$1,130,040	\$2,326,300	\$0	\$0	

Capital Cost Estimates					
Activity	2021		2022		Total Loaded Capital Cost with Contingency
	Direct	Loaded	Direct	Loaded	
Tools for Leak Survey Field Employees	\$403,000	\$485,333	\$0	\$0	\$533,866

Total Revenue Requirement over expected life of investment: \$11.7 million

Average Annual Revenue Requirement: \$5.3 million

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The calculation methodology used to calculate the estimated reduction in emissions is the same methodology used to calculate emissions from the distribution system in the Annual Emissions Report.

1. Derive the annual system leak rates by materials and facilities
2. Estimate the number of leaks detected and their associated emissions when shifting the survey cycle from 5-year and 3 year to annually
3. Project emissions reduction in future years during and after implementation of this best practice

Cost Assumptions

- 6,114 feet surveyed per day per FTE
- Represented Employee Hourly Rate: \$39.73
- 13 Incremental Leak Survey field FTE's
- 2 Incremental Survey Supervisors
- 2 Quality Assurance FTE's
- \$100K annual salary for Supervisors and QA employees
- 10% Contingency is included in the total loaded O&M and Capital cost

Part 5. Cost Effectiveness/Benefits

Standard Cost Effectiveness Calculation:
\$883.77/MCF

Standard Cost Effectiveness Calculation including Cap and Trade Cost Benefits:
\$881.05/MCF

Standard Cost Effectiveness Calculation including Social Cost of Methane Benefits:
\$876.85/MCF

Part 6. Supplemental Information/Documentation

Attachment AK: Redlined Gas Standard 223.0100 Leak Inventory Reduction

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PURPOSE To establish guidelines and requirements for assessing the degree of hazard and classification of leaks or leak indications found on Company piping system, and actions required to provide for public safety and repair of the leak.

1. POLICY AND SCOPE

- 1.1. Leak indications on Company facilities are classified by trained and qualified employees according to location, spread, concentration of gas, possibility for accumulation of gas, possible sources of ignition, potential migration and imminence of hazard to people or property. **Classifications of leaks or leak indications** are based on a relative degree of hazard and examples listed are intended only as a guide. The judgment of the person evaluating the leak or leak indication, after consideration of all factors involved, is the primary criterion for classification and mitigation.
- 1.2. Hazardous indications of underground leaks are reported, and action is taken according to this Gas Standard until the hazard has been eliminated and the leak has been either temporarily or permanently repaired; or until it is determined that the leak is from a source other than the Company piping system. Refer to [GS 184.0220](#), *Field Gas*, for handling of field gas.
- 1.3. Classification of a leak or leak indication establishes a maximum time limit from date of detection for taking corrective action. Dates may be set for action prior to the maximum time limit for safety, public relations reasons, or other special considerations by trained and qualified employees.

Note: In a situation where a leak requires an earlier scheduled repair, the employee must contact supervision and share all pertinent information by the end of that working day. The Supervisor must take the necessary actions to bring these situations to the attention of the individual responsible for scheduling leakage repair to expedite the leak repair.

Note: Although a repair of a classified leak may be expedited for a variety of reasons, the original classification of the leak shall not be changed.

- 1.4. In the event that leakage is discovered in the vicinity of a pipeline operating at greater than 60 PSIG, refer to [GS 183.06](#), *Reports of Safety-Related Pipeline Conditions*, to determine any additional reporting requirements and actions.

Note: Storage piping solely under the jurisdiction of the Department of Oil, Gas, and Geothermal Resources (DOGGR) is not subject to these policies. DOT-defined Distribution piping includes the meter set assembly (MSA) up to the inlet of the Customer's piping.

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2. RESPONSIBILITIES AND QUALIFICATIONS

- 2.1. **Pipeline Integrity** is responsible for the specific guidelines as it relates to regulatory requirements and ensuring compliance with the Company's Integrity Management Plan.
- 2.2. **Gas Operations Staff and Technical Service** is responsible for the process of duties performed and the equipment utilized for assessing the degree of hazard and classification of leaks or leak indications found.
- 2.3. **Distribution, Transmission, and Storage** qualified field employees are required to code all leak indications in the vicinity of buried DOT Transmission and Distribution Defined Company pipelines and facilities in accordance with this gas standard.
- 2.4. **Distribution, Transmission, and Storage** qualified field employees are required to notify Supervision of all leak indications detected on a buried pipeline with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing), SEE [GS 184.0245](#), *Leak Investigation*, Section 2.2.
- 2.5. **Distribution, Transmission, and Storage Supervisors** are required to notify the appropriate **Gas Operations Area Manager, Transmission District Operations Manager, and/or Storage Operations Manager** of all leak indications detected on a buried pipeline with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing), SEE [GS 184.0245](#) *Leak Investigation, Section, See Section 2.4.*
- 2.6. **Distribution, Transmission, Storage, M&R and Customer Services** qualified field employees are required to classify all leaks identified on above ground (not buried) DOT Transmission and Distribution Defined Company pipelines and facilities in accordance with this gas standard.
- 2.7. Assigning leakage classifications must be performed by trained and qualified individuals refer to [GS 167.0100](#), *Operator Qualification Program*.
- 2.8. When **any Company department** detects a non-hazardous leak or leak indications on a facility operated by another Company department, notification to that department shall be made the same day or within one business day

Note: A company employee finding hazardous leak indications must remain at the location performing activities to their ability and training to keep themselves, the public and the area safe until the responding employee(s) to correct the leak has arrived.

- 2.9. **Gas Operations Training** is responsible for ensuring the equipment and facilities used by an Operator for training and qualification of employees must be identical, or

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very similar in operation to the equipment and facilities which the employee will use, or on which the employee will perform the covered task per GO112-F 143.4.

- 2.10. Trained and Qualified Employees re-evaluating coded leaks or leak indications are required to check for changes in location, spread, concentration of gas, possibility for accumulation of gas, possible sources of ignition, potential migration and imminence of hazard to people or property

2.10.1. When conditions change, and Hazardous Indications are detected:

- 2.10.1.1. Trained and qualified employees must notify supervision and remain at the location performing activities to their ability and training to keep themselves, the public and the area safe until the appropriate support personnel has responded to isolate and correct the leak has arrived.
- 2.10.1.2. When conditions have changed, and the leak is recognized as not hazardous but justifies scheduled repairs based on the potential for creating a future hazard:
- 2.10.1.3. Trained and qualified employees must contact supervision and share all pertinent information by the end of that working day.
- 2.10.1.4. Supervisors must take the necessary actions to bring these situations to the attention of the individual responsible for scheduling leakage repair to expedite the leak repair

Note: Although a repair of a classified leak may be expedited for a variety of reasons, the original coding/classification of the leak shall not be changed.

3. DEFINITIONS

- 3.1. **Explosive Limits for Natural Gas** - 4.5% to 15% Gas Volume (gas / air mixture).
 - 3.1.1. **Lower Explosive Limit (LEL)** - 4.5% Gas Volume (100% of the LEL) indicate the lower explosive range of gas.
- 3.2. **Repair** - As it relates to this Gas Standard, is defined as a permanent modification to the gas facilities that eliminates the natural gas leak.
- 3.3. **Permanent Repair** – As it relates to this Gas Standard, is defined as an approved modification or installation of an approved fitting to the gas facility which eliminates

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the leak. Permanent repairs are conducted per Gas Standards and do not require any additional return visits to address the original leak indications.

- 3.4. **Temporary Repair** - As it relates to this Gas Standard is defined as a temporary modification to the gas facilities that eliminates the natural gas leak and will require a return visit to complete a permanent repair.

Note: Drilling and purging bar holes (sometimes is referred to as aeration) is not considered a temporary repair. This process is utilized for verifying and centering below ground leak indications. Refer to [GS 184.0245](#), *Leak Investigation – Distribution* for drilling and purging of bar holes.

- 3.5. **Temporary Leak Clamps** – Company approved clamps used for temporarily repairing leaks on PE pipe until an approved permanent repair could be made, see [GS 184.0235](#), *Polyethylene (PE) Pipe Repair* [GS 184.0240](#), *PE Tapping Tee and Service Saddle Repair*.
- 3.6. **Remote location** - As it relates to this Gas Standard is defined as a company facility that is located a sufficient distance from any building or structure intended for human occupancy, roadways, and walkways (excluding roadways and walkways within Company facilities that are restricted from public access).
- 3.7. **Leak** – A leak is defined as an unintentional escape of gas from a gas facility.
- 3.8. **Leakage Coding** – As it relates to GO 112 F within this document – A “Grade 1” leak is referred to as a Code 1 leak, a “Grade 2” leak is referred to as a Code 2 leak, and a “Grade 3” leak is referred to as a Code 3 leak.
- 3.8.1. Below ground leak indications are coded.
- 3.8.2. Above ground leak indications are classified, see GS 223.0126, *Above Ground Leakage Classification and Mitigation Schedules*.
- 3.9. **Leak Concentration** - The amount of leakage registered on the leak detection instrument.
- 3.10. **Buried Service Leaks** – Leaks on service piping below ground, including the vertical buried portion of the service pipe. These leaks should be coded 1, 2 or 3.

Note: Below ground leaks are never classified Hazardous, Non-Hazardous or Minor.

3.11. **BELOW GROUND LEAK INDICATIONS**

- 3.11.1. **CODE 1 LEAK INDICATION** - a leak that represents an existing or probable hazard to persons or property and requiring prompt action,

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immediate repair (temporarily or permanently) and continuous action until the conditions are no longer hazardous.

Note: Temporary or permanent repairs must be made to eliminate the immediate hazard however; code 1 leak repairs must be scheduled and completed per section 4.1.1 of this Gas Standard.

3.11.1.1. Examples of Code 1 leak indications include, but are not limited to:

3.11.1.1.1. Any leak, which in the judgment of the trained and qualified employee at the scene, is regarded as an immediate hazard

3.11.1.1.2. Blowing gas that can be seen, heard, or felt.

3.11.1.1.3. Escaping gas that has ignited unintentionally.

3.11.1.1.4. Any indication of gas which has migrated into or under a building or tunnel; or at the outside wall of a building, or where gas could potentially migrate to an outside wall of a building.

3.11.1.1.5. A leak with gas indications of 67% LEL (3% gas/air mixture) or greater in substructures that people can enter.

3.11.1.1.6. A leak with gas indications of 80% LEL (3.6% gas / air mixture) or greater in an enclosed space.

3.11.1.1.7. A leak with gas indications of 67% LEL (3% gas/air mixture) or greater in enclosures containing electrical equipment.

3.11.1.1.8. A leak with gas indications of 80% LEL (3.6% gas / air mixture) or greater in small substructures not associated with gas facilities where the gas could potentially migrate to the outside wall of a building.

3.11.1.1.9. A leak with gas indications of 80% LEL (3.6% gas / air mixture) or greater near buildings or structures within 5 feet if unpaved and where it is likely or unlikely gas could potentially migrate to the outside wall of a building.

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3.11.1.1.10. Any reading of 100% LEL (4.5% gas / air mixture) or greater under a street in a wall-to-wall paved area.

3.11.2. **CODE 2 LEAK INDICATION** - a leak that is recognized as being not-hazardous at the time of detection, but justifies scheduled repair based on the potential for creating a future hazard.

Note: Permanent repairs must be scheduled and completed per section 4.1.2 of this Gas Standard.

3.11.2.1. Examples of Code 2 leak indications include, but are not limited to:

3.11.2.1.1. A leak with gas indications of less than 80% LEL (3.6% gas / air mixture) near buildings or structures within 5 feet if unpaved that does not qualify as a Code 1 leak and where it is unlikely gas could potentially migrate to the outside wall of a building.

3.11.2.1.2. Any reading of 40% LEL to 80% LEL (1.8% to 3.6% gas / air mixture) under a sidewalk in a wall-to-wall or continuously paved area that does not qualify as a Code 1 leak and where it is unlikely gas could potentially migrate to the outside wall of a building.

3.11.2.1.3. Any reading less than 100% LEL (4.5% gas / air mixture) under a street in a wall-to-wall paved area that does not qualify as a Code 1 leak and where it is unlikely gas could potentially migrate to the outside wall of a building.

3.11.2.1.4. A leak with gas indications of less than 3% gas/air mixture in substructures that people can enter.

3.11.2.1.5. A leak with gas indications of less than 80% LEL (3.6% gas / air mixture) in an enclosed space.

3.11.2.1.6. A leak with gas indications of less than 67% LEL (3% gas/air mixture) in enclosures containing electrical equipment.

3.11.2.1.7. A leak with gas indications of less than 80% LEL (3.6% gas / air mixture) in small substructures not associated with gas facilities and where it is unlikely gas could potentially migrate creating a probable future hazard.

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3.11.2.1.8. Any reading on a pipeline operating at greater than 60 PSIG that is not a Code 1 leak.

Note: For **Transmission and Storage**, pipelines operating at greater than 60 PSIG may be assigned a Code 3 leak category when the leak is confined to a valve casing and not in the surrounding soil. See Code 3 leak indications.

3.11.3. **CODE 3 LEAK INDICATION** - a leak that is not-hazardous at the time of detection and can reasonably be expected to remain not-hazardous.

Note: Permanent repairs must be scheduled and completed per section 4.1.3 of this Gas Standard.

3.11.3.1. Leak indications that do **not** meet Code 1 or Code 2 criteria should be classified as a Code 3.

Note: Includes leak indications that involve plastic pipe.

3.11.3.2. Examples of Code 3 leaks include, but are not limited to:

3.11.3.2.1. Any gas indications of less than 80% LEL (3.6% gas / air mixture) in small gas associated substructures and **in the surrounding soil**, such as but not limited to small curb meter boxes or gas valve boxes where it is unlikely the gas could migrate to the outside wall of a building.

Note: Any gas indications of less than 80% LEL (3.6% gas / air mixture) in small gas associated substructures and **NOT in the surrounding soil**, such as but not limited to small curb meter boxes **will be classified** in accordance to GS 223.0126, *Above Ground Leakage Classification and Mitigation Schedules*.

3.11.3.2.2. Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building.

3.11.3.2.3. Any reading less than 40% LEL (1.8% gas / air mixture) under a sidewalk in a wall-to-wall or continuously paved area that does not qualify as a Code 1 or Code 2 leak and where it is unlikely gas could potentially migrate to the outside wall of a building.



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3.11.3.2.4. For Transmission and Storage, leaks confined to a valve casing and not in the surrounding soil involving a pipeline operating at greater than 60 PSIG may be assigned a Code 3 leak category provided that the indications do not meet Code 1 or Code 2 criteria.

Note: Permanent repairs must be scheduled and completed per section 4.1.3.2 of this Gas Standard.

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Table A: BELOW GROUND LEAK INDICATION CODING CRITERIA

LEAK INDICATION CODING	The corresponding leak indication coding applies to the conditions and actions listed below	
	CONDITIONS / ENVIRONMENT	ACTIONS (One or more actions may be required)
CODE 1	<ul style="list-style-type: none"> - Ignited leak - Leak is in a location where the gas could be ignited and pose an immediate danger to public or property. 	<ul style="list-style-type: none"> - Requires prompt action, immediate repair or continuous action until the leak is repaired (temporarily or permanently) and the conditions are no longer hazardous; - Evacuation; - Delineation to control public access; - Traffic delineation to control vehicular access; - Eliminating source of ignition; - Venting the area; - Stand-by; - Stopping the flow of gas by closing valves or other means; or - Notifying police and fire departments.
CODE 2	<ul style="list-style-type: none"> - Leak is not ignited. - Does not pose an immediate danger to public or property. - Is not hazardous at the time of detection but justifies scheduled repair based on the potential for creating a future hazard. 	<p>Follow procedures in section 4.1.2.</p>
CODE 3	<ul style="list-style-type: none"> - Does not pose an immediate danger to public or property. - Is not hazardous and is not expected to become hazardous. 	<p>Follow procedures in section 4.1.3.</p>

Note:

- The condition of the facility does not factor into the classification of the leak; however, pipe condition and structural integrity should be considered when determining the repair schedule. For Transmission, Storage, and Distribution employees working on a system operating at greater than 60 PSIG, the pipe and facility condition shall also be assessed per Company Form Instruction **677-1**, *Pipeline Condition and Maintenance Report*.
- Refer to [GS 183.03](#), *Field Guidelines - Emergency Incident Distribution / Customer Service* for additional instructions.

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4. PROCEDURE

4.1. Below Ground Leak Classification, Response and Mitigation

Note: All below ground leaks on DOT-defined Transmission, Storage and Distribution piping shall be coded and documented according to the definitions and criteria requirements within this gas standard.

Note: The Supervisor of the organization repairing the leak must be notified upon discovery of leak indications on buried pipelines with an MAOP of 20% SMYS or more, SEE [GS 184.0245](#).

4.1.1. Code 1 Leak Indications

4.1.1.1. All Code 1 leak indications require prompt action, immediate repair (temporarily or permanently), and continuous action until the conditions are no longer hazardous.

4.1.1.1.1. Temporary repairs may be made and documented to eliminate the immediate hazard. Refer to section 4.1.1.3 and 4.1.1.4.

4.1.1.2. Actions taken for Code 1 leak indications in **Distribution, Transmission, and Storage** are in accordance with [GS 183.03](#), *Field Guidelines - Emergency Incident Distribution / Customer Service* and [GS 223.0100](#), *Leakage Surveys*.

Note: The Supervisor of the organization repairing the leak must be notified for all Code 1 leaks.

4.1.1.3. Distribution

4.1.1.3.1. When a temporary repair is made on a Code 1 leak, the leak must be reevaluated using an approved Combustible Gas Indicator (CGI) at least once every 6 months from the original date detected.

4.1.1.3.1.1. Temporary repairs made on PE pipe utilizing “Temporary Repair Leak Clamps” cannot be backfilled and must be safely covered, as well as monitored for leakage and repaired following the guidelines provided in Section 4.2.

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Note: All Temporary repairs on PE pipe utilizing approved “Temporary Repair Leak Clamps” require approval from Supervisor.

4.1.1.3.1.2. Temporary leak repairs on pipelines operating at 60 PSIG or less must be permanently repaired no later than 15 months from the original date detected.

4.1.1.3.1.3. Temporary leak repairs on pipelines operating at **greater than 60 PSIG** must be permanently repaired within 1 year from the original date detected.

4.1.1.3.1.4. All Code 1 leaks detected prior to January 1, 2017 are subject to the repair time periods set forth in the previous version of 223.0125.

4.1.1.4. Transmission and Storage

4.1.1.4.1. When a Code 1 leak is temporarily repaired on a pipeline operating at greater than 60 PSIG, a permanent repair must be scheduled and completed within 6 months from the original date detected.

Note: In situations where permanent repairs cannot be completed within the six-months, the reason for delay and the steps taken to ensure public safety shall be documented monthly until the leak is permanently repaired, not to exceed one year from the original date detected

4.1.2. Code 2 Leak Indications

Note: The Supervisor of the organization repairing the leak must be notified upon discovery of leak indications on buried pipelines with an MAOP of 20% SMYS or more, SEE [GS 184.0245](#).

4.1.2.1. Distribution

4.1.2.1.1. Code 2 leak indications must be reevaluated, using an approved Combustible Gas Indicator (CGI), at least once every 6 months from the original date detected. The frequency of reevaluation should be determined by the location and magnitude of the leakage condition.

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- 4.1.2.1.1.1. Leaks on a pipeline operating at **60 PSIG or less** must be permanently repaired or cleared within 15 months from the original date detected.
- 4.1.2.1.1.2. Leaks on a pipeline operating at greater than 60 PSIG must be permanently repaired or cleared within 1 year from the original date detected.
- 4.1.2.1.1.3. When a temporary repair is made on a Code 2 leak, the leak must be reevaluated using an approved Combustible Gas Indicator (CGI) at least once every 6 months from the original date detected.

Note: All Temporary repairs on PE pipe utilizing approved “Temporary Repair Leak Clamps” require approval from Supervisor.

- 4.1.2.1.1.4. Temporary leak repairs on a pipeline operating at **60 PSIG or less** must be permanently repaired no later than 15 months from the original date detected. See Section 4.2 for temporary leak repairs made on PE pipe utilizing temporary leak clamps
 - 4.1.2.1.1.4.1. Temporary leak repairs on a pipeline operating at **greater than 60 PSIG** must be permanently repaired within 1 year from the original date detected.
- 4.1.2.1.2. In determining the repair schedule, the following criteria should be considered:
 - 4.1.2.1.2.1.1. Amount and migration of gas.
 - 4.1.2.1.2.1.2. Proximity of gas to buildings and subsurface structures.
 - 4.1.2.1.2.1.3. Extent of pavement.
 - 4.1.2.1.2.1.4. Soil type, and soil conditions (e.g., frost cap, moisture, natural venting).
- 4.1.2.1.3. Code 2 leak indications may vary greatly in degree of potential hazard and may justify a reason to expedite scheduled repair.

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Note: In a situation where the Code 2 requires an earlier scheduled repair, the employee must contact supervision and share all pertinent information by the end of that working day. The Supervisor must take the necessary actions to bring these situations to the attention of the individual responsible for scheduling leakage repair to expedite the leak repair.

4.1.2.1.4. When leak indications are found in a Company-owned or controlled gas vault, entry into the vault is to be done in accordance with [GS 166.0077](#), *Confined Space Operations*.

4.1.2.2. Transmission and Storage

4.1.2.2.1. An investigation of a Code 2 leak indication shall be conducted within 6 weeks of the date detected and repaired within 6 months of the date detected using normal operational methods.

4.1.2.2.2. Code 2 leak indications in the upper range of the lower explosive limit (2.5% - 3% gas / air mixture) shall be monitored pending the leak repair. The frequency for monitoring shall be defined by the supervisor.

Note: In situations where permanent repairs cannot be completed within the six-months, the reason for delay and the steps taken to ensure public safety shall be documented monthly until the leak is permanently repaired not to exceed one year from the original date detected

4.1.2.2.3. When leak indications are found in a Company-owned or controlled gas vault, entry into the vault is to be done in accordance with [GS 166.0077](#), *Confined Space Operations*.

4.1.3. Code 3 Leak Indications

Note: The Supervisor of the organization repairing the leak must be notified upon discovery of leak indications on buried pipelines with an MAOP of 20% SMYS or more, SEE [GS 184.0245](#).

4.1.3.1. Distribution

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4.1.3.1.1. Code 3 leak indications must be reevaluated, using an approved Combustible Gas Indicator (CGI) and on intervals based on the piping material in the area of the leak indication:

Steel: At least once every calendar year, not to exceed 15 months from the original date detected until the leak is repaired. The leak must be repaired or cleared no later than 36 months from the original date detected.

Plastic: At least once every 6 months from the original date detected until a permanent repair is completed, leak is cleared. The leak must be repaired or cleared no later than 15 months from the original date detected.

Note: Code 3 leaks discovered before June 15th, 2017 must be repaired no later than June 15th, 2020.

4.1.3.1.1.1.1. Temporary repairs made on PE pipe utilizing “Temporary Repair Leak Clamps” cannot be backfilled and must be safely covered, as well as monitored for leakage and repaired following the guidelines provided in Section 4.2.

Note: All Temporary repairs on PE pipe utilizing approved “Temporary Repair Leak Clamps” require approval from Supervision

4.1.3.2. Transmission and Storage

4.1.3.2.1. Leaks confined to a valve casing and not in the surrounding soil may be assigned a Code 3 leak category provided that the indications do not meet Code 1 or Code 2 criteria.

4.1.3.2.1.1. Code 3 leak indications must be permanently repaired / or cleared upon discovery or within one year from the original date detected.

4.2. Guidelines and requirements when leak repairs are made on Polyethylene (PE) Pipe utilizing Temporary Leak Clamps.

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Note: Temporary Leak Repair Clamps may not be used as a permanent repair method for plastic pipe.

4.2.1. Approved “Temporary Leak Clamp” may be used as a temporary repair for leakage on PE pipe for immediate control (such as overnight) until an approved permanent repair could be made, [GS 184.0235](#), *Polyethylene (PE) Pipe Repair* and [GS 184.0240](#), *PE Tapping Tee and Service Saddle Repair*.

Note: All Temporary repairs on PE pipe utilizing approved “Temporary Repair Leak Clamps” require approval from a Supervision.

- 4.2.1.1. Temporary repair clamps are not approved for service in a buried application.
- 4.2.1.2. See Table C for approved “Temporary Leak Clamps” for polyethylene pipe.

Approved “Temporary Leak Clamps”	
Code #	Clamp Size
N561760	2"
N561762	3"
N561764	4"
N561806	6"

TABLE C

4.2.2. All Temporary repairs on PE pipe utilizing approved “Temporary Repair Leak Clamps” require approval from Supervision. Excavation cannot be backfilled and must be safely covered, as well as monitored for leakage and repaired following the guidelines below (See Table D):

- 4.2.2.1. Temporary Leak Clamps installed within 3 feet of a structure or a source of ignition must be monitored for leakage daily. Permanent repairs must be completed within 10 business days not to exceed the established compliance due date from date of detection.

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4.2.2.2. Temporary Leak Clamps installed greater than 3 feet from a building or structure that is within a business district must be monitored for leakage weekly. Permanent repairs must be made within 6 months not to exceed the established compliance due date from date of detection.

4.2.2.3. Temporary Leak Clamps installed greater than 3 feet from a building or structure not in a business district and not in a remote location must be monitored for leakage monthly. Permanent repairs must be made within 6 months not to exceed the established compliance due date from date of detection.

4.2.2.4. Temporary Leak Clamps installed greater than 3 feet from a building or structure in a remote location not considered hazardous must be monitored for leakage quarterly. Permanent repairs must be made per the current leakage mitigation schedule.

<u>Temporary Leak Clamps installed:</u>	<u>Within 3 feet from Structure or source of ignition</u>		<u>Greater than 3 feet from Structure or source of ignition</u>	
	Monitoring Frequency	Repair Frequency	Monitoring Frequency	Repair Frequency
Business District	Daily	*Not to exceed 10 business days	Weekly	*Not to exceed 6 months
Populated Area (not Business District)	Daily	*Not to exceed 10 business days	Monthly	*Not to exceed 6 months
Remote Location	Daily	*Not to exceed 10 business days	Quarterly	*Not to exceed 6 months
*Not to exceed the established compliance due date from date of detection				

TABLE D

5. EXCEPTION PROCEDURE

(See [GS 182.0004](#), Exception Procedure for Company Operations Standards)

- 5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

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- 5.2. An exception from a standard shall not be allowed unless [GS 182.0004](#) *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.
6. OPERATOR QUALIFICATION COVERED TASKS
(See [GS 167.0100](#), *Operator Qualification Program*, Appendix A, *Covered Task List*):
- **Task 09.05** - CFR 192.703, 192.723(b) - Leakage Assessment.
 - **Task 09.06-9999** - 49 CFR 192.703 - Above Ground Leak Classification.
7. RECORDS
- 7.1. **Transmission:** Leak records are documented on [Form 677-1](#), *Pipeline Condition and Maintenance Report*. For all documentation instructions and requirements, refer to [Form 677-1](#), *Pipeline Condition and Maintenance Report* company form instructions. The PCMR can be completed electronically or paper forms.
- 7.2. **Storage:** Except for minor leaks, leak records are documented on [Form 677-1](#), *Pipeline Condition and Maintenance Report*. For all documentation instructions and requirements, refer to [Form 677-1](#), *Pipeline Condition and Maintenance Report* company form instructions. The PCMR can be completed electronically or paper forms. Minor leaks are documented in MAXIMO.
- 7.3. **Distribution:** Leak records are documented as follows:
- **Form 4040**, Leak Investigation Order.
 - **Form 4060**, Leak Re-Evaluation Order.
 - [Form 4050](#), *Leak Repair Order PDF*, Leak repairs on mains, services and risers.
 - **Form 4070**, *Leak repair Order*, Leak repair on the MSA.
 - [Form 677-1](#), *Pipeline Condition and Maintenance Report* (PCMR), when a leak is repaired on a pipeline operating at greater than 60 PSIG, a description and all pertinent information concerning the repair(s) or any other disposition of the leak is made on **Form 677-1**; CM work orders and PCMRs are to be cross referenced. CM orders are completed and electronically filed in SAP. PCMRs are completed and filed according to [Form 677-1](#) instructions.
- 7.4. **Measurement and Regulation:** Distribution M&R inspections and leak repairs are captured by CLICK Mobile. Transmission M&R inspections and leak repairs are captured by a PDF version of the form. Above Ground Leaks will be captured using Leak Classification & Repair Form (**Form 5290** for FL and **Form 5590** for EQ).
- 7.5. **Customer Service Field:** Leak records are documented in PACER and shall include the leak classification, cause, facility location, leaking component, conditions found, and a description of the subsequent repairs or other disposition of the leak.

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- 7.6. Records of leaks discovered, and repairs made are filed by the appropriate Transmission District, Storage Field, Customer Service or Distribution operating organizations.
- 7.7. **Transmission Lines: Recordkeeping:**
 - 7.7.1. All records of leaks discovered and repaired are kept on file at Gas Transmission in MAXIMO.
 - 7.7.2. All leaks found and not immediately repaired must have a corrective MAXIMO work order completed.
 - 7.7.3. Retain original paper order in file per Records Management Retention Schedule. See Records Retention Standards on Sempra Net, <http://home.sempranet.com/rm/>.
 - 7.7.4. In addition to the other recordkeeping requirements of these rules, each Operator shall maintain the following records for transmission lines for the periods specified:
 - A. The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipeline remains in service or there is no longer pipe within the system of the same manufacturer, size and / or vintage as the pipeline on which repairs are made, whichever, is longer.
 - B. The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 75 years. Repairs or findings of easement encroachments, generated by patrols, surveys, inspections, or tests required by subparts L and M of 49 CFR Part 192 must be retained in accordance with paragraph (c) of this section.
 - C. A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 75 years.
- 8. APPENDICES
 - 8.1. N/A



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NOTE: Do not alter or add any content from this page down; the following content is automatically generated.

Brief: Conducted a functional review to re-establish 5-year review cycle; Reformatted to comply with document outline requirements; Removed Above Ground Leakage Classification Mitigation and Response requirements and moved information to a newly created Gas Standard 223.0126, Above Ground Leakage Classification and Mitigation Schedules. Section 3. DEFINITIONS – Added section 3.11.1.1 Any leak, which in the judgment of the trained and qualified employee at the scene, is regarded as an immediate hazard. Section 4. PROCEDURE - Revised section 4.1.3.1.1 adding SB 1371 Mitigation repair requirements for Code 3 leaks. Section 7, Section 4.2 added a Note Temporary Leak Repair Clamps may not be used as a permanent repair method for plastic pipe. RECORDS - Added Section 7.2 Record requirements for Storage.

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PURPOSE To establish guidelines and requirements for assessing the degree of hazard and classification of leaks or leak indications found on Company piping system, and actions required to provide for public safety and repair of the leak.

1. POLICY AND SCOPE

- 1.1. Leak indications on Company facilities are classified by trained and qualified employees according to location, spread, concentration of gas, possibility for accumulation of gas, possible sources of ignition, potential migration and imminence of hazard to people or property. **Classifications of leaks or leak indications** are based on a relative degree of hazard and examples listed are intended only as a guide. The judgment of the person evaluating the leak or leak indication, after consideration of all factors involved, is the primary criterion for classification and mitigation.
- 1.2. Hazardous indications of underground leaks are reported, and action is taken according to this Gas Standard until the hazard has been eliminated and the leak has been either temporarily or permanently repaired; or until it is determined that the leak is from a source other than the Company piping system. Refer to [GS 184.0220](#), *Field Gas*, for handling of field gas.
- 1.3. Classification of a leak or leak indication establishes a maximum time limit from date of detection for taking corrective action. Dates may be set for action prior to the maximum time limit for safety, public relations reasons, or other special considerations by trained and qualified employees.

Note: In a situation where a leak requires an earlier scheduled repair, the employee must contact supervision and share all pertinent information by the end of that working day. The Supervisor must take the necessary actions to bring these situations to the attention of the individual responsible for scheduling leakage repair to expedite the leak repair.

Note: Although a repair of a classified leak may be expedited for a variety of reasons, the original classification of the leak shall not be changed.

- 1.4. In the event that leakage is discovered in the vicinity of a pipeline operating at greater than 60 PSIG, refer to [GS 183.06](#), *Reports of Safety-Related Pipeline Conditions*, to determine any additional reporting requirements and actions.

Note: Storage piping solely under the jurisdiction of the Department of Oil, Gas, and Geothermal Resources (DOGGR) is not subject to these policies. DOT-defined Distribution piping includes the meter set assembly (MSA) up to the inlet of the Customer's piping.

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2. RESPONSIBILITIES AND QUALIFICATIONS

- 2.1. **Pipeline Integrity** is responsible for the specific guidelines as it relates to regulatory requirements and ensuring compliance with the Company's Integrity Management Plan.
- 2.2. **Gas Operations Staff and Technical Service** is responsible for the process of duties performed and the equipment utilized for assessing the degree of hazard and classification of leaks or leak indications found.
- 2.3. **Distribution, Transmission, and Storage** qualified field employees are required to code all leak indications in the vicinity of buried DOT Transmission and Distribution Defined Company pipelines and facilities in accordance with this gas standard.
- 2.4. **Distribution, Transmission, and Storage** qualified field employees are required to notify Supervision of all leak indications detected on a buried pipeline with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing), SEE [GS 184.0245](#), *Leak Investigation*, Section 2.2.
- 2.5. **Distribution, Transmission, and Storage Supervisors** are required to notify the appropriate **Gas Operations Area Manager, Transmission District Operations Manager, and/or Storage Operations Manager** of all leak indications detected on a buried pipeline with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing), SEE [GS 184.0245](#) *Leak Investigation, Section, See Section 2.4.*
- 2.6. **Distribution, Transmission, Storage, M&R and Customer Services** qualified field employees are required to classify all leaks identified on above ground (not buried) DOT Transmission and Distribution Defined Company pipelines and facilities in accordance with this gas standard.
- 2.7. Assigning leakage classifications must be performed by trained and qualified individuals refer to [GS 167.0100](#), *Operator Qualification Program*.
- 2.8. When **any Company department** detects a non-hazardous leak or leak indications on a facility operated by another Company department, notification to that department shall be made the same day or within one business day

Note: A company employee finding hazardous leak indications must remain at the location performing activities to their ability and training to keep themselves, the public and the area safe until the responding employee(s) to correct the leak has arrived.

- 2.9. **Gas Operations Training** is responsible for ensuring the equipment and facilities used by an Operator for training and qualification of employees must be identical, or

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very similar in operation to the equipment and facilities which the employee will use, or on which the employee will perform the covered task per GO112-F 143.4.

- 2.10. Trained and Qualified Employees re-evaluating coded leaks or leak indications are required to check for changes in location, spread, concentration of gas, possibility for accumulation of gas, possible sources of ignition, potential migration and imminence of hazard to people or property

2.10.1. When conditions change, and Hazardous Indications are detected:

- 2.10.1.1. Trained and qualified employees must notify supervision and remain at the location performing activities to their ability and training to keep themselves, the public and the area safe until the appropriate support personnel has responded to isolate and correct the leak has arrived.
- 2.10.1.2. When conditions have changed, and the leak is recognized as not hazardous but justifies scheduled repairs based on the potential for creating a future hazard:
- 2.10.1.3. Trained and qualified employees must contact supervision and share all pertinent information by the end of that working day.
- 2.10.1.4. Supervisors must take the necessary actions to bring these situations to the attention of the individual responsible for scheduling leakage repair to expedite the leak repair

Note: Although a repair of a classified leak may be expedited for a variety of reasons, the original coding/classification of the leak shall not be changed.

3. DEFINITIONS

- 3.1. **Explosive Limits for Natural Gas** - 4.5% to 15% Gas Volume (gas / air mixture).
 - 3.1.1. **Lower Explosive Limit (LEL)** - 4.5% Gas Volume (100% of the LEL) indicate the lower explosive range of gas.
- 3.2. **Repair** - As it relates to this Gas Standard, is defined as a permanent modification to the gas facilities that eliminates the natural gas leak.
- 3.3. **Permanent Repair** – As it relates to this Gas Standard, is defined as an approved modification or installation of an approved fitting to the gas facility which eliminates

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the leak. Permanent repairs are conducted per Gas Standards and do not require any additional return visits to address the original leak indications.

- 3.4. **Temporary Repair** - As it relates to this Gas Standard is defined as a temporary modification to the gas facilities that eliminates the natural gas leak and will require a return visit to complete a permanent repair.

Note: Drilling and purging bar holes (sometimes is referred to as aeration) is not considered a temporary repair. This process is utilized for verifying and centering below ground leak indications. Refer to [GS 184.0245](#), *Leak Investigation – Distribution* for drilling and purging of bar holes.

- 3.5. **Temporary Leak Clamps** – Company approved clamps used for temporarily repairing leaks on PE pipe until an approved permanent repair could be made, see [GS 184.0235](#), *Polyethylene (PE) Pipe Repair* [GS 184.0240](#), *PE Tapping Tee and Service Saddle Repair*.
- 3.6. **Remote location** - As it relates to this Gas Standard is defined as a company facility that is located a sufficient distance from any building or structure intended for human occupancy, roadways, and walkways (excluding roadways and walkways within Company facilities that are restricted from public access).
- 3.7. **Leak** – A leak is defined as an unintentional escape of gas from a gas facility.
- 3.8. **Leakage Coding** – As it relates to GO 112 F within this document – A “Grade 1” leak is referred to as a Code 1 leak, a “Grade 2” leak is referred to as a Code 2 leak, and a “Grade 3” leak is referred to as a Code 3 leak.
- 3.8.1. Below ground leak indications are coded.
- 3.8.2. Above ground leak indications are classified, see GS 223.0126, *Above Ground Leakage Classification and Mitigation Schedules*.
- 3.9. **Leak Concentration** - The amount of leakage registered on the leak detection instrument.
- 3.10. **Buried Service Leaks** – Leaks on service piping below ground, including the vertical buried portion of the service pipe. These leaks should be coded 1, 2 or 3.

Note: Below ground leaks are never classified Hazardous, Non-Hazardous or Minor.

3.11. **BELOW GROUND LEAK INDICATIONS**

- 3.11.1. **CODE 1 LEAK INDICATION** - a leak that represents an existing or probable hazard to persons or property and requiring prompt action,

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immediate repair (temporarily or permanently) and continuous action until the conditions are no longer hazardous.

Note: Temporary or permanent repairs must be made to eliminate the immediate hazard however; code 1 leak repairs must be scheduled and completed per section 4.1.1 of this Gas Standard.

3.11.1.1. Examples of Code 1 leak indications include, but are not limited to:

3.11.1.1.1. Any leak, which in the judgment of the trained and qualified employee at the scene, is regarded as an immediate hazard

3.11.1.1.2. Blowing gas that can be seen, heard, or felt.

3.11.1.1.3. Escaping gas that has ignited unintentionally.

3.11.1.1.4. Any indication of gas which has migrated into or under a building or tunnel; or at the outside wall of a building, or where gas could potentially migrate to an outside wall of a building.

3.11.1.1.5. A leak with gas indications of 67% LEL (3% gas/air mixture) or greater in substructures that people can enter.

3.11.1.1.6. A leak with gas indications of 80% LEL (3.6% gas / air mixture) or greater in an enclosed space.

3.11.1.1.7. A leak with gas indications of 67% LEL (3% gas/air mixture) or greater in enclosures containing electrical equipment.

3.11.1.1.8. A leak with gas indications of 80% LEL (3.6% gas / air mixture) or greater in small substructures not associated with gas facilities where the gas could potentially migrate to the outside wall of a building.

3.11.1.1.9. A leak with gas indications of 80% LEL (3.6% gas / air mixture) or greater near buildings or structures within 5 feet if unpaved and where it is likely or unlikely gas could potentially migrate to the outside wall of a building.

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3.11.1.1.10. Any reading of 100% LEL (4.5% gas / air mixture) or greater under a street in a wall-to-wall paved area.

3.11.2. **CODE 2 LEAK INDICATION** - a leak that is recognized as being not-hazardous at the time of detection, but justifies scheduled repair based on the potential for creating a future hazard.

Note: Permanent repairs must be scheduled and completed per section 4.1.2 of this Gas Standard.
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3.11.2.1. Examples of Code 2 leak indications include, but are not limited to:

3.11.2.1.1. A leak with gas indications of less than 80% LEL (3.6% gas / air mixture) near buildings or structures within 5 feet if unpaved that does not qualify as a Code 1 leak and where it is unlikely gas could potentially migrate to the outside wall of a building.

3.11.2.1.2. Any reading of 40% LEL to 80% LEL (1.8% to 3.6% gas / air mixture) under a sidewalk in a wall-to-wall or continuously paved area that does not qualify as a Code 1 leak and where it is unlikely gas could potentially migrate to the outside wall of a building.

3.11.2.1.3. Any reading less than 100% LEL (4.5% gas / air mixture) under a street in a wall-to-wall paved area that does not qualify as a Code 1 leak and where it is unlikely gas could potentially migrate to the outside wall of a building.

3.11.2.1.4. A leak with gas indications of less than 3% gas/air mixture in substructures that people can enter.

3.11.2.1.5. A leak with gas indications of less than 80% LEL (3.6% gas / air mixture) in an enclosed space.

3.11.2.1.6. A leak with gas indications of less than 67% LEL (3% gas/air mixture) in enclosures containing electrical equipment.

3.11.2.1.7. A leak with gas indications of less than 80% LEL (3.6% gas / air mixture) in small substructures not associated with gas facilities and where it is unlikely gas could potentially migrate creating a probable future hazard.

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3.11.2.1.8. Any reading on a pipeline operating at greater than 60 PSIG that is not a Code 1 leak.

Note: For **Transmission and Storage**, pipelines operating at greater than 60 PSIG may be assigned a Code 3 leak category when the leak is confined to a valve casing and not in the surrounding soil. See Code 3 leak indications.

3.11.3. **CODE 3 LEAK INDICATION** - a leak that is not-hazardous at the time of detection and can reasonably be expected to remain not-hazardous.

Note: Permanent repairs must be scheduled and completed per section 4.1.3 of this Gas Standard.

3.11.3.1. Leak indications that do **not** meet Code 1 or Code 2 criteria should be classified as a Code 3.

Note: Includes leak indications that involve plastic pipe.

3.11.3.2. Examples of Code 3 leaks include, but are not limited to:

3.11.3.2.1. Any gas indications of less than 80% LEL (3.6% gas / air mixture) in small gas associated substructures and **in the surrounding soil**, such as but not limited to small curb meter boxes or gas valve boxes where it is unlikely the gas could migrate to the outside wall of a building.

Note: Any gas indications of less than 80% LEL (3.6% gas / air mixture) in small gas associated substructures and **NOT in the surrounding soil**, such as but not limited to small curb meter boxes **will be classified** in accordance to GS 223.0126, *Above Ground Leakage Classification and Mitigation Schedules*.

3.11.3.2.2. Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building.

3.11.3.2.3. Any reading less than 40% LEL (1.8% gas / air mixture) under a sidewalk in a wall-to-wall or continuously paved area that does not qualify as a Code 1 or Code 2 leak and where it is unlikely gas could potentially migrate to the outside wall of a building.



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3.11.3.2.4. For Transmission and Storage, leaks confined to a valve casing and not in the surrounding soil involving a pipeline operating at greater than 60 PSIG may be assigned a Code 3 leak category provided that the indications do not meet Code 1 or Code 2 criteria.

Note: Permanent repairs must be scheduled and completed per section 4.1.3.2 of this Gas Standard.

INTERNAL

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Table A: BELOW GROUND LEAK INDICATION CODING CRITERIA

LEAK INDICATION CODING	The corresponding leak indication coding applies to the conditions and actions listed below	
	CONDITIONS / ENVIRONMENT	ACTIONS (One or more actions may be required)
CODE 1	<ul style="list-style-type: none"> - Ignited leak - Leak is in a location where the gas could be ignited and pose an immediate danger to public or property. 	<ul style="list-style-type: none"> - Requires prompt action, immediate repair or continuous action until the leak is repaired (temporarily or permanently) and the conditions are no longer hazardous; - Evacuation; - Delineation to control public access; - Traffic delineation to control vehicular access; - Eliminating source of ignition; - Venting the area; - Stand-by; - Stopping the flow of gas by closing valves or other means; or - Notifying police and fire departments.
CODE 2	<ul style="list-style-type: none"> - Leak is not ignited. - Does not pose an immediate danger to public or property. - Is not hazardous at the time of detection but justifies scheduled repair based on the potential for creating a future hazard. 	<p>Follow procedures in section 4.1.2.</p>
CODE 3	<ul style="list-style-type: none"> - Does not pose an immediate danger to public or property. - Is not hazardous and is not expected to become hazardous. 	<p>Follow procedures in section 4.1.3.</p>

Note:

- The condition of the facility does not factor into the classification of the leak; however, pipe condition and structural integrity should be considered when determining the repair schedule. For Transmission, Storage, and Distribution employees working on a system operating at greater than 60 PSIG, the pipe and facility condition shall also be assessed per Company Form Instruction **677-1**, *Pipeline Condition and Maintenance Report*.
- Refer to [GS 183.03](#), *Field Guidelines - Emergency Incident Distribution / Customer Service* for additional instructions.

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4. PROCEDURE

4.1. **Below Ground Leak Classification, Response and Mitigation**

Note: All below ground leaks on DOT-defined Transmission, Storage and Distribution piping shall be coded and documented according to the definitions and criteria requirements within this gas standard.

Note: The Supervisor of the organization repairing the leak must be notified upon discovery of leak indications on buried pipelines with an MAOP of 20% SMYS or more, SEE [GS 184.0245](#).

4.1.1. Code 1 Leak Indications

4.1.1.1. All Code 1 leak indications require prompt action, immediate repair (temporarily or permanently), and continuous action until the conditions are no longer hazardous.

4.1.1.1.1. Temporary repairs may be made and documented to eliminate the immediate hazard. Refer to section 4.1.1.3 and 4.1.1.4.

4.1.1.2. Actions taken for Code 1 leak indications in **Distribution, Transmission, and Storage** are in accordance with [GS 183.03](#), *Field Guidelines - Emergency Incident Distribution / Customer Service* and [GS 223.0100](#), *Leakage Surveys*.

Note: The Supervisor of the organization repairing the leak must be notified for all Code 1 leaks.

4.1.1.3. **Distribution**

4.1.1.3.1. When a temporary repair is made on a Code 1 leak, the leak must be reevaluated using an approved Combustible Gas Indicator (CGI) at least once every 6 months from the original date detected.

4.1.1.3.1.1. Temporary repairs made on PE pipe utilizing “Temporary Repair Leak Clamps” cannot be backfilled and must be safely covered, as well as monitored for leakage and repaired following the guidelines provided in Section 4.2.

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Note: All Temporary repairs on PE pipe utilizing approved “Temporary Repair Leak Clamps” require approval from Supervisor.

4.1.1.3.1.2. Temporary leak repairs on pipelines operating at 60 PSIG or less must be permanently repaired no later than 15 months from the original date detected.

4.1.1.3.1.3. Temporary leak repairs on pipelines operating at **greater than 60 PSIG** must be permanently repaired within 1 year from the original date detected.

4.1.1.3.1.4. All Code 1 leaks detected prior to January 1, 2017 are subject to the repair time periods set forth in the previous version of 223.0125.

4.1.1.4. Transmission and Storage

4.1.1.4.1. When a Code 1 leak is temporarily repaired on a pipeline operating at greater than 60 PSIG, a permanent repair must be scheduled and completed within 6 months from the original date detected.

Note: In situations where permanent repairs cannot be completed within the six-months, the reason for delay and the steps taken to ensure public safety shall be documented monthly until the leak is permanently repaired, not to exceed one year from the original date detected

4.1.2. Code 2 Leak Indications

Note: The Supervisor of the organization repairing the leak must be notified upon discovery of leak indications on buried pipelines with an MAOP of 20% SMYS or more, SEE [GS 184.0245](#).

4.1.2.1. Distribution

4.1.2.1.1. Code 2 leak indications must be reevaluated, using an approved Combustible Gas Indicator (CGI), at least once every 6 months from the original date detected. The frequency of reevaluation should be determined by the location and magnitude of the leakage condition.

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- 4.1.2.1.1.1. Leaks on a pipeline operating at **60 PSIG or less** must be permanently repaired or cleared within 15 months from the original date detected.
- 4.1.2.1.1.2. Leaks on a pipeline operating at greater than 60 PSIG must be permanently repaired or cleared within 1 year from the original date detected.
- 4.1.2.1.1.3. When a temporary repair is made on a Code 2 leak, the leak must be reevaluated using an approved Combustible Gas Indicator (CGI) at least once every 6 months from the original date detected.

Note: All Temporary repairs on PE pipe utilizing approved “Temporary Repair Leak Clamps” require approval from Supervisor.

- 4.1.2.1.1.4. Temporary leak repairs on a pipeline operating at **60 PSIG or less** must be permanently repaired no later than 15 months from the original date detected. See Section 4.2 for temporary leak repairs made on PE pipe utilizing temporary leak clamps
 - 4.1.2.1.1.4.1. Temporary leak repairs on a pipeline operating at **greater than 60 PSIG** must be permanently repaired within 1 year from the original date detected.
- 4.1.2.1.2. In determining the repair schedule, the following criteria should be considered:
 - 4.1.2.1.2.1.1. Amount and migration of gas.
 - 4.1.2.1.2.1.2. Proximity of gas to buildings and subsurface structures.
 - 4.1.2.1.2.1.3. Extent of pavement.
 - 4.1.2.1.2.1.4. Soil type, and soil conditions (e.g., frost cap, moisture, natural venting).
- 4.1.2.1.3. Code 2 leak indications may vary greatly in degree of potential hazard and may justify a reason to expedite scheduled repair.

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Note: In a situation where the Code 2 requires an earlier scheduled repair, the employee must contact supervision and share all pertinent information by the end of that working day. The Supervisor must take the necessary actions to bring these situations to the attention of the individual responsible for scheduling leakage repair to expedite the leak repair.

4.1.2.1.4. When leak indications are found in a Company-owned or controlled gas vault, entry into the vault is to be done in accordance with [GS 166.0077](#), *Confined Space Operations*.

4.1.2.2. Transmission and Storage

4.1.2.2.1. An investigation of a Code 2 leak indication shall be conducted within 6 weeks of the date detected and repaired within 6 months of the date detected using normal operational methods.

4.1.2.2.2. Code 2 leak indications in the upper range of the lower explosive limit (2.5% - 3% gas / air mixture) shall be monitored pending the leak repair. The frequency for monitoring shall be defined by the supervisor.

Note: In situations where permanent repairs cannot be completed within the six-months, the reason for delay and the steps taken to ensure public safety shall be documented monthly until the leak is permanently repaired not to exceed one year from the original date detected

4.1.2.2.3. When leak indications are found in a Company-owned or controlled gas vault, entry into the vault is to be done in accordance with [GS 166.0077](#), *Confined Space Operations*.

4.1.3. Code 3 Leak Indications

Note: The Supervisor of the organization repairing the leak must be notified upon discovery of leak indications on buried pipelines with an MAOP of 20% SMYS or more, SEE [GS 184.0245](#).

4.1.3.1. Distribution

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4.1.3.1.1. Code 3 leak indications must be reevaluated, using an approved Combustible Gas Indicator (CGI) and on intervals based on the piping material in the area of the leak indication:

Steel: At least once every calendar year, not to exceed 15 months from the original date detected until the leak is repaired. **The leak must be repaired or cleared no later than 15 months from the original date detected.**

Plastic: At least once every 6 months from the original date detected until a permanent repair is completed, leak is cleared. The leak must be repaired or cleared no later than 15 months from the original date detected.

Note: Code 3 leaks discovered before September 31st, 2021 must be repaired no later than December 31st, 2022.

4.1.3.1.1.1. Temporary repairs made on PE pipe utilizing “Temporary Repair Leak Clamps” cannot be backfilled and must be safely covered, as well as monitored for leakage and repaired following the guidelines provided in Section 4.2.

Note: All Temporary repairs on PE pipe utilizing approved “Temporary Repair Leak Clamps” require approval from Supervision

4.1.3.2. Transmission and Storage

4.1.3.2.1. Leaks confined to a valve casing and not in the surrounding soil may be assigned a Code 3 leak category provided that the indications do not meet Code 1 or Code 2 criteria.

4.1.3.2.1.1. Code 3 leak indications must be permanently repaired / or cleared upon discovery or within one year from the original date detected.

4.2. Guidelines and requirements when leak repairs are made on Polyethylene (PE) Pipe utilizing Temporary Leak Clamps.

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Note: Temporary Leak Repair Clamps may not be used as a permanent repair method for plastic pipe.

4.2.1. Approved “Temporary Leak Clamp” may be used as a temporary repair for leakage on PE pipe for immediate control (such as overnight) until an approved permanent repair could be made, [GS 184.0235](#), *Polyethylene (PE) Pipe Repair* and [GS 184.0240](#), *PE Tapping Tee and Service Saddle Repair*.

Note: All Temporary repairs on PE pipe utilizing approved “Temporary Repair Leak Clamps” require approval from a Supervision.

4.2.1.1. Temporary repair clamps are not approved for service in a buried application.

4.2.1.2. See Table C for approved “Temporary Leak Clamps” for polyethylene pipe.

Approved “Temporary Leak Clamps”	
Code #	Clamp Size
N561760	2"
N561762	3"
N561764	4"
N561806	6"

TABLE C

4.2.2. All Temporary repairs on PE pipe utilizing approved “Temporary Repair Leak Clamps” require approval from Supervision. Excavation cannot be backfilled and must be safely covered, as well as monitored for leakage and repaired following the guidelines below (See Table D):

4.2.2.1. Temporary Leak Clamps installed within 3 feet of a structure or a source of ignition must be monitored for leakage daily. Permanent repairs must be completed within 10 business days not to exceed the established compliance due date from date of detection.

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- 4.2.2.2. Temporary Leak Clamps installed greater than 3 feet from a building or structure that is within a business district must be monitored for leakage weekly. Permanent repairs must be made within 6 months not to exceed the established compliance due date from date of detection.
- 4.2.2.3. Temporary Leak Clamps installed greater than 3 feet from a building or structure not in a business district and not in a remote location must be monitored for leakage monthly. Permanent repairs must be made within 6 months not to exceed the established compliance due date from date of detection.
- 4.2.2.4. Temporary Leak Clamps installed greater than 3 feet from a building or structure in a remote location not considered hazardous must be monitored for leakage quarterly. Permanent repairs must be made per the current leakage mitigation schedule.

<u>Temporary Leak Clamps installed:</u>	<u>Within 3 feet from Structure or source of ignition</u>		<u>Greater than 3 feet from Structure or source of ignition</u>	
	Monitoring Frequency	Repair Frequency	Monitoring Frequency	Repair Frequency
Business District	Daily	*Not to exceed 10 business days	Weekly	*Not to exceed 6 months
Populated Area (not Business District)	Daily	*Not to exceed 10 business days	Monthly	*Not to exceed 6 months
Remote Location	Daily	*Not to exceed 10 business days	Quarterly	*Not to exceed 6 months
*Not to exceed the established compliance due date from date of detection				

TABLE D

4.2.3. Minor Leak

4.2.3.1. The leak must be repaired or cleared no later than 15 month from the original date detected.

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5. EXCEPTION PROCEDURE

(See [GS 182.0004](#), Exception Procedure for Company Operations Standards)

- 5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.
- 5.2. An exception from a standard shall not be allowed unless [GS 182.0004](#) *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

6. OPERATOR QUALIFICATION COVERED TASKS

(See [GS 167.0100](#), *Operator Qualification Program*, Appendix A, *Covered Task List*):

- **Task 09.05** - CFR 192.703, 192.723(b) - Leakage Assessment.
- **Task 09.06-9999** - 49 CFR 192.703 - Above Ground Leak Classification.

7. RECORDS

- 7.1. **Transmission:** Leak records are documented on [Form 677-1](#), *Pipeline Condition and Maintenance Report*. For all documentation instructions and requirements, refer to [Form 677-1](#), *Pipeline Condition and Maintenance Report* company form instructions. The PCMR can be completed electronically or paper forms.
- 7.2. **Storage:** Except for minor leaks, leak records are documented on [Form 677-1](#), *Pipeline Condition and Maintenance Report*. For all documentation instructions and requirements, refer to [Form 677-1](#), *Pipeline Condition and Maintenance Report* company form instructions. The PCMR can be completed electronically or paper forms. Minor leaks are documented in MAXIMO.
- 7.3. **Distribution:** Leak records are documented as follows:
 - **Form 4040**, Leak Investigation Order.
 - **Form 4060**, Leak Re-Evaluation Order.
 - [Form 4050](#), *Leak Repair Order PDF*, Leak repairs on mains, services and risers.
 - **Form 4070**, *Leak repair Order*, Leak repair on the MSA.
 - [Form 677-1](#), *Pipeline Condition and Maintenance Report* (PCMR), when a leak is repaired on a pipeline operating at greater than 60 PSIG, a description and all pertinent information concerning the repair(s) or any other disposition of the leak is made on **Form 677-1**; CM work orders and PCMRs are to be cross referenced. CM orders are completed and electronically filed in SAP. PCMRs are completed and filed according to [Form 677-1](#) instructions.

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- 7.4. **Measurement and Regulation:** Distribution M&R inspections and leak repairs are captured by CLICK Mobile. Transmission M&R inspections and leak repairs are captured by a PDF version of the form. Above Ground Leaks will be captured using Leak Classification & Repair Form (**Form 5290** for FL and **Form 5590** for EQ).
- 7.5. **Customer Service Field:** Leak records are documented in PACER and shall include the leak classification, cause, facility location, leaking component, conditions found, and a description of the subsequent repairs or other disposition of the leak.
- 7.6. Records of leaks discovered, and repairs made are filed by the appropriate Transmission District, Storage Field, Customer Service or Distribution operating organizations.
- 7.7. **Transmission Lines: Recordkeeping:**
- 7.7.1. All records of leaks discovered and repaired are kept on file at Gas Transmission in MAXIMO.
- 7.7.2. All leaks found and not immediately repaired must have a corrective MAXIMO work order completed.
- 7.7.3. Retain original paper order in file per Records Management Retention Schedule. See Records Retention Standards on Sempra Net, <http://home.sempranet.com/rm/>.
- 7.7.4. In addition to the other recordkeeping requirements of these rules, each Operator shall maintain the following records for transmission lines for the periods specified:
- A. The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipeline remains in service or there is no longer pipe within the system of the same manufacturer, size and / or vintage as the pipeline on which repairs are made, whichever, is longer.
- B. The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 75 years. Repairs or findings of easement encroachments, generated by patrols, surveys, inspections, or tests required by subparts L and M of 49 CFR Part 192 must be retained in accordance with paragraph (c) of this section.



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- C. A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 75 years.

8. APPENDICES

8.1. N/A

INTERNAL



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NOTE: Do not alter or add any content from this page down; the following content is automatically generated.

Brief: Conducted a functional review to re-establish 5-year review cycle; Reformatted to comply with document outline requirements; Removed Above Ground Leakage Classification Mitigation and Response requirements and moved information to a newly created Gas Standard 223.0126, Above Ground Leakage Classification and Mitigation Schedules. Section 3. DEFINITIONS – Added section 3.11.1.1 Any leak, which in the judgment of the trained and qualified employee at the scene, is regarded as an immediate hazard. Section 4. PROCEDURE - Revised section 4.1.3.1.1 adding SB 1371 Mitigation repair requirements for Code 3 leaks. Section 7, Section 4.2 added a Note Temporary Leak Repair Clamps may not be used as a permanent repair method for plastic pipe. RECORDS - Added Section 7.2 Record requirements for Storage.

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Impacts GO112F	Yes
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Impacts Underground Gas Storage Projects (DOGGR)	No
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***This list is constantly evolving due to the complexity and uncertainty of construction schedules and permitting**

City Fixed	Street	Reason for Certainty	Anticipated Post-June Completion Date
ANAHEIM	215 N HARBOR BLVD(ANNUAL)	Difficult City with regard to permitting. Permit has been under review for several months.	12/31/2020
BURBANK	10418 Oxnard Blvd	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
MISSION HILLS	10436 WOODMAN AVE	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	2929 CRENSHAW BLVD	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	1002 N San Fernando rd	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
MONROVIA	110 w. huntington dr	Complex issues noted. Larger planned job may be necessary with longer timeline.	12/31/2020
HIGHLAND	intersection of highland and orange	Complex issues noted. Larger planned job may be necessary	12/31/2020
FELLOWS	NW CRNR HWY 33 & Cloud Ave	Cal Trans allowing 1 job at a time, difficulty getting approved permit	12/31/2020
FELLOWS	24841 Westside Hwy	Cal Trans allowing 1 job at a time, difficulty getting approved permit	12/31/2020
LOS ANGELES	N SAN FERNANDO RD	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	VALLEY BLVD/BOCA AVE	Length of time for City Approval	12/31/2020
FONTANA	15091 MERRILL AVE	Complex issues noted. Larger planned job may be necessary	12/31/2020
LOS ANGELES	4575 MARMION WAY	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
TAFT	28323 Hwy 119	Cal Trans allowing 1 job at a time, difficulty getting approved permit	12/31/2020
CRESTLINE	int of scenic dr and cresta ln	Complex leak. Planning not anticipated to be complete by deadline	12/31/2020
LOS ANGELES	4159 EAGLE ROCK BLVD.	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	910 SAN FERNANDO RD	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
TWIN PEAKS	26509 lake forest dr	Complex leak. Planning not anticipated to be complete by deadline	12/31/2020
LOS ANGELES	103 E.118TH PLACE	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
SANTA BARBARA	1030 Arbolado Rd.	Low Reads, Difficulty Centering	12/31/2020
BAKERSFIELD	Olen Ave & Enos Lane	Cal Trans allowing 1 job at a time, difficulty getting approved permit	12/31/2020
LOS ANGELES	5670 W. Olympic Blvd.	Length of time for City Approval	12/31/2020
VAN NUYS	14117 Vanowen	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	2316 San Fernando	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	4860 MCCONNELL AVE	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	N/E INTERSECTION SAN FERNANDO RD. & HUMB	Length of time for City Approval	12/31/2020
LOS ANGELES	602 KENTER AVE	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
PASADENA	401 SANTA PAULA AVE	Potential paperwork closeout. If not - high volume district. Complex issues noted	12/31/2020
LOS ANGELES	3833 avenue 42	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
TORRANCE	22606 denker st.	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
BELLFLOWER	16124 Eucalyptus Ave	Complex issues noted. Larger planned job may be necessary	12/31/2020
LYNWOOD	3865 CORTLAND ST.	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
COMPTON	2007 E COMPTON BLVD	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
NORTH HOLLYWOOD	6040 Vineland Ave	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
BANNING	434 CHERRY ST	Main job initially requested. Not feasible within timeline.	12/31/2020
SUN VALLEY	Laurel Canyon Blvd & Sheldon St.	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
POMONA	670 Huntington Blvd	Complex issues noted. Larger planned job may be necessary	12/31/2020

LOS ANGELES	5417 S. Wilton Pl.	Length of time for City Approval	12/31/2020
POMONA	504 FOXPARK DR	Complex. May require larger job to mitigate.	12/31/2020
GLENDALE	3906 Forestglen dr	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
GLENDALE	3912 Forestglen dr	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
GLENDALE	3824 Forestglen dr	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
BURBANK	124 S Keystone St	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
BAKERSFIELD	Enos Ln	Cal Trans allowing 1 job at a time, difficulty getting approved permit	12/31/2020
ROLLING HILLS ESTATES	3 LAZY CREEK LN	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
PALM SPRINGS	1082 RACQUET CLUB RD.	Per district - pipe requires replacement. Job not approved for planning 1/28	12/31/2020
ANAHEIM	1203 E Flower St	Difficult city to attain permit	12/31/2020
MONROVIA	1035 Norumbega Rd.	Potential paperwork closeout	12/31/2020
ANAHEIM	843 West Street	Anaheim City has arduous permit review periods/timelines	12/31/2020
VAN NUYS	14318 ROSCOE BLVD	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
SUN VALLEY	7878 Claybeck Ave	Length of time for City Approval	12/31/2020
SUN VALLEY	7866 Claybeck Ave	Length of time for City Approval	12/31/2020
IRVINE	Spectrum & Irvine Center Dr	Pending work currently in Planning and not permitted.	12/31/2020
LOS ANGELES	1030 S. Los Angeles St.	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
CARUTHERS	11690 Polk Ave	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
SHAFTER	@ Median of HWY 43	Cal Trans allowing 1 job at a time, difficulty getting approved permit	12/31/2020
BELL	4600 Florence Ave	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
TAFT	24886 West Side Hwy 33	Cal Trans allowing 1 job at a time, difficulty getting approved permit	12/31/2020
ANAHEIM	1313 S Harbor Blvd	Anaheim City has arduous permit review periods/timelines	12/31/2020
NORTH HOLLYWOOD	6710 Klump Ave	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
SHERMAN OAKS	4801 Ranchito Ave.	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	12544 Presnell St	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
ARCADIA	408 ALSTER ST.	Complex leak. Larger mitigation measures necessary. No planning complete.	12/31/2020
PACOIMA	12960 Kagel Cyn St	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
SOUTH PASADENA	2018 CAMDEN PKWY	Originally Service replacement with Customer issue	12/31/2020
EL MONTE	2405 Seaman ave	High volume of existing repair work. No dedicated leak crew. Going to move forward with regular permitting	12/31/2020
LOS ANGELES	5520 Santa Monica Blvd	Length of time for City Approval	12/31/2020
TAFT	100 ft east from SE corner of golfcourse RD/119 t	Cal Trans allowing 1 job at a time, difficulty getting approved permit	12/31/2020
LA CRESCENTA-MONTR	5153 PENNSYLVANIA AVE	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	909 w.Temple St	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
ARCADIA	433 E Duarte Rd.	Complex issues noted. Larger planned job may be necessary	12/31/2020
PASADENA	3265 Green St	Complex issues noted. Larger planned job may be necessary	12/31/2020
VAN NUYS	6320 Van Nuys Blvd	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
COMPTON	119 N CULVER AVE	Job is in IP Status. Pending Update from Tech Svc	12/31/2020

PASADENA	250 ALTADENA DR.	Pending work currently in Planning and not permitted.	12/31/2020
GLENDAL	3825 Hillway Dr	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
COMPTON	1309 E ELM ST	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	821 S Eastman Ave	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
BURBANK	1238 N Pass Ave	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	3535 ATLANTIC ST.	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	11036 ANZIO RD	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LYNWOOD	3323 BURTON AVE	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
SUN VALLEY	9315 Sunland Blvd	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
ALTADENA	128 e. harriet	Complex issues noted. Larger planned job may be necessary	12/31/2020
CANOGA PARK	7629 De Soto Ave.	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
ARCADIA	820 Encino PL	Under paving moratorium	12/31/2020
LOS ANGELES	1055 East Cesar E. Chavez Ave	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	706 Ducommun St	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
LOS ANGELES	7122 VAN NESS AVE.	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
CRESTLINE	23342 crest forest	Pending work currently in Planning and not permitted.	12/31/2020
RIMFOREST	1208 Scenic Pl	Pending work currently in Planning and not permitted.	12/31/2020
LOS ANGELES	9807 BANDERA ST	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
BALDWIN PARK	puente ave and dutch st.	Leak is at main-to-main tie in and 2" gutless-tee. High volume of alterations/leads in district already.	12/31/2020
LOS ANGELES	3356 Pepper St	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
SAN MARINO	2446 Oak Knoll Ave	Pending work currently in Planning and not permitted.	12/31/2020
YUCAIPA	34494 AVENUE H	Pending work currently in Planning and not permitted.	12/31/2020
PACOIMA	13368 Louvre St	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
GLENDAL	111 Verdug Rd	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
TUJUNGA	10138 Mt Gleason Ave	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
BURBANK	1016 E WALNUT AVE	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
SAN BERNARDINO	1267 N Waterman Ave	Pending work currently in Planning and not permitted.	12/31/2020
LYNWOOD	10695 WASHINGTON AVE	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
BURBANK	511 S. SHELTON ST.	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
CORCORAN	5734 Newark Ave	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
SAN BERNARDINO	157 49th St.	Pending work currently in Planning and not permitted.	12/31/2020
HIGHLAND	6083 mirada ct	Pending work currently in Planning and not permitted.	12/31/2020
LA HABRA	1801 La Habra blvd	Pending work currently in Planning and not permitted.	12/31/2020
LOS ANGELES	1146 Sierra Alta Way	Job is in IP Status. Pending Update from Tech Svc	12/31/2020
OJAI	407 El Paseo Rd.	Job is in IP Status. Pending Update from Tech Svc	12/31/2020

Attachment D: Updated Gas Standards**GS 183.01 - Shutdown Procedures and Isolation Area Establishment for Distribution Pipeline Facilities**

- Section 1.5 updated to provide guidelines for Project Managers and Planners to reduce methane emissions while planning projects

GS 184.06 Gas-Handling and Pressure Control

- Section 4.1.4.2 added to provide guidelines for Project Managers and Planners to reduce methane emissions while creating gas-handling or pressure control procedures

GS 184.006 - General Construction Requirements for Distribution Service Lines

- Section 1.6 modified to ensure reference to 184.06

GS 182.0160 - Purging Pipelines and Components

- Section 5.3.6 added to provide guidelines for Project Managers and Planners to reduce methane emissions while creating purge procedures

GS 184.0015 - Construction Planning for Mains and Supply Lines

- Section 4.4.9 modified to ensure reference to 184.06

GS 223.0145 - Planning Shutdowns for Transmission and Storage

- Section 4.1.4 added to provide guidelines for Operations to reduce methane emissions while planning shutdowns

G7909 - Purging Pipelines and Components

- Section 5.3.6 added to provide guidelines for Project Managers and Planners to reduce methane emissions while creating purge procedures

Form 3466 - Reporting of Gas Blown to Atmosphere

- Form updated to mirror Form 7011 and track emissions reductions from blowdown events
- Although form is already in use it has not officially been published as of 2/14/2020, the form attached is a draft

Form 7011 - Blowdown Emission Reduction Plan Form

- Form created to track emissions reductions for planned blowdown events
- Although form is already in use it has not officially been published as of 2/14/2020, the form attached is a draft

Company Operations Standard Gas Standard Gas Engineering

Shutdown Procedures and Isolation Area Establishment for Distribution Pipeline Facilities	SCG:	183.01
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PURPOSE To describe the planning, coordination, and notifications necessary for planned and emergency shutdowns of Distribution pipelines and to establish isolation area requirements.

1. POLICY AND SCOPE

- 1.1. **Distribution Regions** follow these guidelines in preparation for planned or emergency shutdown of segments of medium pressure districts.
- 1.2. A written shut down plan is prepared when:
 - 1.2.1. Work on medium pressure Distribution lines involves the re-routing of gas that may impact more than 25,000 customer's meters.
 - 1.2.2. Work on supply lines and/or regulator stations would significantly alter (displacement of one million cubic feet or more per hour) the flow of gas required from the **Transmission** system, affect flow of gas to a Utility Electrical Generation (UEG) customer, or affect receipt of gas from a producer.
- 1.3. **Distribution Regions** select an emergency shutdown plan that meets the needs of each situation and targets safe and practical facility restoration to minimize hazards to life or property.
- 1.4. **Distribution Regions** design, establish and maintain isolation areas so that each area contains no more than 25,000 customer meters.
- 1.5. **Project Managers, Project Engineers, and Planners will build time into the project schedule to reduce methane emissions when planned shutdowns require gas blown to atmosphere.**
 - 1.5.1. Consider alternative sources of supply to maintain service to customers and maintain project feasibility.
 - 1.5.2. Operating pressure should be reduced to the lowest operationally feasible level to minimize methane emissions before non-emergency venting of high-pressure distribution, transmission and underground storage infrastructure consistent with safe operations.
 - 1.5.3. Work should be bundled to prevent multiple venting of the same piping, when practicable.

2. RESPONSIBILITIES & QUALIFICATIONS

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Shutdown Procedures and Isolation Area Establishment for Distribution Pipeline Facilities	SCG:	183.01
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- 2.1. Ahead of any proposed shutdown period, **Distribution Planning & Engineering**:
 - 2.1.1. Coordinates planned and probable emergency shutdowns with **Gas Control**.
 - 2.1.2. Coordinates with **Transmission Technical Services** on planned shutdowns and probable emergency shutdowns of pipelines that affect **Transmission**.
 - 2.1.3. Coordinates planned shutdowns and probable emergency shutdowns described in the scope that affect **Distribution Field Operations** with both the **Measurement & Regulation Operations Manager** and the **Area Resource Manager**.
 - 2.2. **Project Managers, Operating Supervisors**, and other **Company personnel** responsible for projects that necessitate shutdowns shall notify **Energy Markets** and/or **Commercial/Industrial Services** when a shutdown affects the flow of gas to UEG/wholesale customers or affects Producers.
 - 2.3. **Gas Control** reviews planned shutdowns and related plans; coordinates changes in planning schedules; coordinates with suppliers, producers, and UEG/wholesale customers; and advises **Distribution Planning & Engineering** regarding gas handling arrangements (valve operations, etc.).
 - 2.4. **Distribution Field Operations, Measurement & Regulation Operations Manager**, and **Area Resource Manager** review planned shutdowns and advise **Distribution Planning & Engineering** regarding gas handling arrangements (e.g., providing input on valve operating procedures for the Measurement & Regulation technicians).
 - 2.5. **Distribution Planning & Engineering** designs and establishes isolation area boundaries; confirms that pipeline system changes preserve boundary integrity; and periodically reviews the customer count in each isolation area.
 - 2.6. **Asset Maintenance & Inspection department** maintains the attributes such as the valve location, type, size and status of isolation area valves in SAP.
3. DEFINITIONS
- 3.1. EOC – Emergency Operations Center
 - 3.2. Isolation Area – a pre-established medium pressure operating area that can be physically shutdown by the closing of isolation valves in the event of an emergency as defined in Section 5.1

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Shutdown Procedures and Isolation Area Establishment for Distribution Pipeline Facilities	SCG:	183.01
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- 3.3. Isolated Section – any section of pipeline facility that is physically shutdown in an emergency or planned shutdown
 - 3.4. Medium Pressure – MAOP of 60 psig or less
 - 3.5. High Pressure – MAOP of greater than 60 psig
 - 3.6. Pressure District – Network of pipes operating at a common pressure with an MAOP less than or equal to 60 psig
 - 3.7. Pressure Zone – Network of pipes operating at a common pressure with an MAOP greater than 60 psig
4. PLANNED SHUTDOWN PROCEDURE
- 4.1. Coordination With Gas Control
 - 4.1.1. For planned shutdowns described in section 1.2, **Distribution Planning & Engineering** shall notify **Gas Control** of any possible timing flexibility to enhance coordination with other planned shutdowns.
 - 4.1.2. When shutdown **operations** are deemed significant by **Gas Control**, **Distribution Planning & Engineering** report the details of which valves will be shut, when, and for how long, seven days in advance of the shutdown.
 - 4.1.3. **Gas Control** may request additional information as needed.
 - 4.1.4. **Distribution Planning & Engineering** and **Measurement & Regulation groups** work with **Gas Control** to minimize gas blown to atmosphere through the use of other **Distribution** facilities to reduce gas line pack prior to blow down.
 - 4.2. **Distribution Planning & Engineering** notifies the following parties (if affected):
 - **Transmission Field Operations and/or Transmission Technical Services Manager**
 - **Storage Technical Services Manager** and affected **Storage Operations Manager**
 - **Distribution Field Operations, Measurement & Regulation Manager** and/or **Area Resource Managers**.

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4.3. Written Shutdown Plans

4.3.1. **Distribution Planning & Engineering** develops written plans for handling planned shutdowns described in Section 1.2. Plans are specific and definitive in order to maintain well established operations.

4.3.1.1. Plans must include procedures for starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits, plus the build-up allowed for operation of pressure-limiting and control devices.

4.3.2. **Distribution Field Operations** provide their field operations personnel with a written plan for gas facility shutdowns delineating all critical activities associated with the shutdown.

4.3.3. The shutdown plan and subsequent job discussion includes, but is not limited to, the following information. The level of detail should be appropriate to the safe and efficient completion of the project:

- List of work to be accomplished prior to the shutdown.
- List of crucial equipment needed at the job site including hazardous materials cleanup equipment.
- List of all concerned governmental agencies, affected **Transmission and Storage personnel**, other Company personnel, local businesses, and residents to be notified.
- Sequence of operations, including numbers and locations of valves to be operated and the estimated time when these operations will occur.
- Schematic of the section to be shut down with all pertinent valves and valve positions clearly labeled.
- List of all active customers or customer taps.

NOTE: All taps feeding a customer(s) must have a plan for an alternate feed that identifies who is responsible for the alternate feed.

- Schematics of the installation and removal sections.
- Detailed step-by-step procedure for all fire-control activities. See [STANDARD 223.0165](#), *Controlled Fire Operations*. Detailed, step-by-

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step procedure for any purge performed. See [STANDARD 182.0160](#), *Purging Pipelines and Components*.

- Plan for personnel protection using Lockout/Tag-out when required.
- List of impacts to telemetry and pressure monitoring devices (e.g., out of service data signals, availability of pressure monitoring).

4.3.4. With no less than seven (7) working days' notice, prepare and distribute [FORM 3506](#), *Notice of Shutdown / Operational Deviation*, which notifies **Gas Control**, affected **Transmission** and **Storage Technical Services**, **Distribution Operations**, and/or **Major Markets** and confirms the arrangements and schedule of all shutdowns. If the date of the shutdown is likely to change, make a note to that effect on [FORM 3506](#). Reach an agreement between **Transmission** and **Storage Operations** organization, **Distribution Regions**, other affected parties, and **Gas Control** as to the minimum amount of time prior to the shutdown that a firm date must be set.

5. EMERGENCY SHUTDOWN PROCEDURE

5.1. In the event of a major or wide-spread emergency (e.g., earthquake, terrorist attack, flooding, firestorm, natural gas shortage, etc.) and the **EOC** is activated and operational to respond to the event, the **EOC Director** should discuss the following three (3) factors with the **Executive-in-Charge** and **Gas Control** before implementing a shutdown in large isolated sections in the gas system unless Section 5.2.2.3.2 applies:

1. Size of Isolated Section

- The isolated section is large enough to encompass an isolation area
- The isolated section is a whole pressure district with more than one District Regulator Station
- The isolated section will impact 25,000 or more customer meters (restores)
- The isolated section could result in displacement of one million cubic feet or more per hour on the flow of gas required from the Transmission system

2. Impacts to Sensitive/Critical Customers

- Health/Safety

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- Hospitals
- Schools
- Stadiums/Large Public Gathering Sites/Arenas/Sports Centers that can be used for evacuation shelters
- Municipal Gas Systems (e.g., Long Beach Gas)
- City/County/State Emergency Operation Centers that are open and running (See ER-1 Ch 12 for more information)
- Economic
 - Non-core firm UEG customers
 - Refineries
 - Co-Generation Facilities (> 20 megawatts)
- Major Airports (e.g., Los Angeles International Airport (LAX), San Diego International Airport (SAN), John Wayne Airport (SNA), LA/Ontario International Airport (ONT), Bob Hope Airport (BUR))
- 3. Need for Inter-Region Coordination or Mutual Assistance
 - Response across multiple operating organizations or with assistance from outside the Company is required to implement the isolated section
- 5.2. When implementing a shutdown of a large-scale isolated section of the gas system, the responsible **Distribution management person** or **EOC Director** shall:
 - 5.2.1. **Initiate a Message Center Report.** See [STANDARD 183.05](#), *Reports to the Message Center*
 - 5.2.2. **Evaluate Response Criteria** to determine the appropriate mitigation method.
 - 5.2.2.1. **Table 1** lists the criteria that should be used when determining the appropriate mitigation method to respond to an incident. A more complete guideline may be found in [STANDARD 183.03](#), *Field Guidelines — Emergency Incident*.
 - 5.2.2.2. Squeezing operations shall be performed according to the standards listed in **Table 2**.

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5.2.2.3. When Affecting Supply Lines:

5.2.2.3.1. Consult with the **Gas Control Supervisor** to arrange the re-routing of gas, operation of valves, and/or obtaining permission to close off connections prior to shutting down supply lines that affect the flow of gas to UEG/wholesale customers or that would significantly alter normal source gas (pressure/volume) from the Transmission system or that would affect producers.

5.2.2.3.2. Consultation or permission from **Gas Control Supervisor** *is not* needed when the responsible **Distribution management person** at the site determines any of the following:

- Injury or death have occurred or is imminent
- Communications are not possible from the site and leaving the site would risk additional damage or injury. In such cases the Gas Control Supervisor is notified at the first opportunity directly or by the EOC (if activated).

TABLE 1: RESPONSE CRITERIA

CONTROL METHOD	CRITERIA
Squeezing	<ul style="list-style-type: none"> • May be utilized when there is a localized incident with no practical access to valves or PC fittings • Can be performed on both polyethylene and steel pipe (see Table 2) • Should only be used on steel piping installed after 1932
Closing of Valves and/or Pressure Control Fittings	<ul style="list-style-type: none"> • May be used to shutdown small sections of the system • May be utilized when squeezing is inappropriate or when there is difficulty in accessing an incident site • Shutdown of a supply line should be performed with sectionalizing valves installed on the supply line
Shutdown of an Isolation Area	<ul style="list-style-type: none"> • May be performed in the event of multiple line breaks • May be implemented when the number of incidents exceeds the Company's ability to mitigate an incident locally

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CONTROL METHOD	CRITERIA
	<ul style="list-style-type: none"> May be implemented when the affected area is approaching the size of the isolation area
Shutdown of a Pressure District	<ul style="list-style-type: none"> Can be used to shutdown a small pressure district with less than 25,000 customers and limited feeds Is used to shutdown a large pressure district (more than 25,000 customers) only when maintaining safety warrants the wide-scale disruption of service to customers

TABLE 2: SQUEEZING REQUIREMENTS

TYPE	REQUIREMENT
Polyethylene Pipe	<ul style="list-style-type: none"> Shall be performed according to GS 184.0340 for all plastic pipe
Hot and Cold Squeezing of Steel Pipe	<ul style="list-style-type: none"> Shall be performed according to GS 184.0310 for 1-¼” and smaller steel pipe Shall be performed according to GS 184.0315 for 1-½” and smaller steel pipe Shall be performed according to GS 184.0320 for 2” steel pipe Shall be performed according to GS 184.0330 for 3” and 4” steel pipe Shall be performed according to GS 184.0335 for 6” through 12” steel pipe

5.2.3. Select Type of Mitigation Method to Response

5.2.3.1. Squeezing near an emergency incident site.

5.2.3.2. Closing of the nearest main-line or regulator station valve

5.2.3.3. Utilization of the nearest pressure control fitting

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IMPORTANT NOTE #1: Squeezing, closing of nearest valves, and the utilization of pressure control fittings are responses designed to minimize the number of affected customers and to expedite restores. These responses should only be used when an incident can be safely managed by isolating one or more localized sections of the Distribution system.

5.2.3.4. Isolation and/or shutdown of an affected isolation area

5.2.3.5. Shutdown of a pressure district or pressure zone

IMPORTANT NOTE #2: Isolation area, pressure district, or pressure zone shutdowns are responses to minimize hazard of life and property in an event of a major or wide-spread emergency.

5.3. Isolation Area Establishment and Requirements

- 5.3.1. Each isolation area will have pre-defined valves that may be used to isolate an area.
- 5.3.2. Each isolation area valve is a critical valve and shall be inspected as per [STANDARD 184.16](#), *Valve Inspection and Maintenance – Distribution*.
- 5.3.3. As part of the regular planning process, new pipe installation or configuration changes shall be evaluated to confirm that the integrity of the associated isolation area is preserved. If an isolation area is compromised, **Distribution Planning & Engineering** re-establishes the boundaries of the affected isolation area in accordance with this Gas Standard.
- 5.3.4. **Distribution Planning & Engineering** evaluates isolation area boundaries for accuracy on a five-year cycle. Each isolation area shall also be checked for potential impact to adjacent areas in the event of an emergency shutdown.
- 5.3.5. Plans must include procedures for starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits, plus the build-up allowed for operation of pressure-limiting and control devices.

5.4. Isolation Area Design

- 5.4.1. Each isolation area shall not exceed 25,000 customer meters

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- 5.4.2. It is recommended to consider establishing an isolation area for pipeline segments susceptible to natural disasters (e.g. landslides, flooding) as long as the 25,000 customer meter limit is not exceeded.
- 5.4.3. The customer meter count in each isolation area should be reviewed and noted on an 18-month cycle by Distribution **Region Engineering**. If the customer meter count exceeds the 25,000 customer meter limit, **Region Engineering** shall evaluate the isolation area to re-establish new isolation boundaries to meet the appropriate size requirements before the next review process.
- 5.4.4. **Distribution Planning & Engineering** shall design, construct, and maintain each isolation area such that:
 - 5.4.4.1. The isolation area boundaries are established with valves.
 - 5.4.4.2. Supply lines are not used as part of an isolation area system.
 - 5.4.4.3. The outlet valves at regulator stations in combination with open valves within the pressure district are designated as the control points to isolate each isolation area.
 - 5.4.4.4. If a pressure district has less than 25,000 customer meters, then the pressure district boundaries may be used to define the isolation area. If this option is used, all valves, if any, used to define the pressure district must be tracked in SAP.
- 5.4.5. The locations of all schools and hospitals should be tracked and be identifiable in the event of an emergency.

6. EXCEPTION PROCEDURE

(See [GS 182.0004](#), *Exception Procedure for Company Operations Standards*)

- 6.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.
- 6.2. An exception from a standard shall not be allowed unless [GS 182.0004](#), *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

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7. RECORDS

Isolation Area Documentation

- 7.1. Each **Region** shall maintain its isolation areas and the locations of its isolation valves on the **Company's Geographical Information System (GIS)**. When an isolation area extends into an adjacent Distribution Region, the affected **Planning & Engineering Managers** for each Region shall agree on who will have primary responsibility for maintenance of the isolation area.
- 7.2. Each isolation valve shall be identified as a critical valve and have maintenance history. Attributes such as the valve location, type, size and status should be included in SAP and be maintained by the **Asset Maintenance & Inspection Department**.
- 7.3. If an isolation valve is replaced or relocated, a new valve number will be assigned in SAP. The old valve number shall be deactivated in SAP.

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NOTE: Do not alter or add any content from this page down; the following content is automatically generated.

Brief: Fully reviewed. The Emission Strategy Program (also known as Leak Abatement) is working to ensure that we comply with SB1371, which aims to reduce methane emissions from our operations. One of the requirements for SB 1371 is to implement blowdown reduction activities whenever possible. GS 183.01 has a new section 1.5 under Policy and Scope that outlines what is expected when a planned shutdown requires gas blown to atmosphere.

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Part of Storage IMP (SIMP)	No
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Company Operations Standard Gas Standard Gas System Integrity Staff & Programs

Gas-Handling and Pressure Control	SCG:	184.06
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PURPOSE: To provide guidelines and requirements for gas handling/shutdown and pressure control operations that involve introducing or interrupting gas flow. This includes the operation of valves, pressure control fittings, and squeeze closures to prevent overpressure of pipelines beyond Maximum Allowable Operating Pressure (MAOP).

1. POLICY AND SCOPE

1.1. This Standard establishes guidelines and requirements for written gas handling plans, alternative gas handling plans and various considerations when performing gas handling/pressure control on the gas piping system. Employees are to adhere to these guidelines when performing these duties.

1.2. Precautions

1.2.1. Prior to a shut-down, **take precautions** to prevent outage, over and under pressurization caused by unknown obstructions, a rapid increase in load, and/or errors in mapping or planning.

1.2.2. Adhere to all safety concerns and policies.

1.2.3. Utilize approved gauges and/or temporary EPM (electronic pressure monitor) devices to mitigate over-pressure or under-pressure events as part of the Distribution gas handling procedures.

1.2.3.1. When the project creates a dead-end that is not rated for the available source pressure, a temporary EPM installation is *required* to be part of the gas handling to remotely monitor a terminal point within that dead-end portion *when* personnel are not available on site to monitor. The temporary EPM shall remain in service until the potential for over-pressurization or under pressurization of the dead-end is eliminated. **See Section 4.1.5.**

1.3. When multiple departments (Distribution, M&R, Transmission, and/or Storage) are working the same project, the completion of [Form 2865, Gas Handling/Shutdown Coordination Form](#), is required. This form is used to coordinate critical handoffs between departments during the Gas Handling/Shutdown instructions created specifically for that project. **See Company Form Instruction 2865.**

1.4. All “**planned blowdowns**” that have the potential to create external activity (media attention, customer odor calls, etc.), will require Supervisors performing the planned blowdown to send an email to Blowdown@semprautilities.com at least 5 days prior to planned blowdown. This email address contains all “internal” contacts that may need to be informed to prepare for potential responses or communications (**See Section 2.1**).

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2. RESPONSIBILITIES AND QUALIFICATIONS

2.1. **Supervision performing a “planned blowdown” (See Section 1.4)** are responsible to send an email to [REDACTED] at least 5 days prior to the planned blowdown. The email will contain the following information:

- **Title the subject line** of the email “Planned Blowdown: Insert name of city/county or cities/counties impacted”.
- The **location information** should include as much as the following as possible: Section Segment Number, GPS, address, street intersection, project name (title, work order number).
- A **brief description** of the project (i.e., pipeline number, pressure, blowdown duration, equipment used, etc.).
- A **general description of the area surrounding the project area** (i.e., within 1 mile). Urban or Rural, critical facilities (hospitals, schools, etc.), major landmarks, freeways, major streets, intersections, residential, business, or otherwise. The description should give the recipient an understanding of the surrounding environment in relationship to the project.
- If possible, a screen-print or attachment of a **map** that provides a general understanding of the surroundings: freeways, major streets, critical facilities (hospitals, schools, etc.), residents, businesses, etc. The map should be viewable from any handheld device.
- Please notate **if assistance will be needed** from other departments: Public Affairs, Office of Media and Public Information, etc.

Note: In the event there are revisions to the planned blow-down, Field Supervision shall send a follow up email to blowdown@semprautilities.com detailing the changes.

2.2. For a single project that includes multiple departments, it is the responsibility of the **department initiating the project** to assign an **Operations Coordinator**. See [Form 2865](#).

2.2.1. The **Operations Coordinator** will be responsible for communications between the departments and initiating/maintaining any changes during the Gas Handling/Shutdown process.

2.3. **Each organization** is responsible to designate specific supervisors to be responsible for gas handling/shutdown operations. The following guidelines are intended to indicate the extent this responsibility may be delegated on various types of work:

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- 2.3.1. Written Gas Handling/Shutdown plans are required for work involving transmission lines, supply lines, medium pressure mains, high pressure services, power-generating plants and any job that is extensive enough for safe handling of gas as determined by the Planner and/or Supervisor. The plans shall be reviewed by the Region Field Operations Manager *and* Gas Control (where applicable) except in an emergency.
- 2.3.2. Written Gas Handling/Shutdown plans shall be prepared for other pre-planned projects that require pressure control operations. This includes medium pressure services being tied to the main or tied to another service (as a branch) using any fitting *larger than* a 2-inch steel service tee and/or 2-inch PE SMC fitting.

NOTE: Steel and PE tees installed ‘inline’ on main to obtain full opening will require a Gas Handling plan regardless of size.

- 2.3.2.1. The Distribution Gas Handling Instructions are provided separately in Word format and are used in conjunction with the gas handling locations depicted on the construction sketch. See [GS 192.0010](#), *Preparation of Construction Sketches*, and **Appendix A** of this document.
- 2.3.2.2. As a part of the project package pre-construction routing for reviews, the Planner creates and finalizes a Planner’s Sketch and preliminary Gas Handling plan. These items along with any pertinent project contents are routed for review, signatures, corrections and/or recommendations. See [GS 184.0016](#), *Main Construction Project Routing*.
- 2.3.2.3. At post-construction, the responsible supervisor will sign and date the Distribution Gas Handling Instructions to verify the operations were performed as planned.
- 2.3.2.3.1. If the performance of the actual gas handling operations varies significantly from the Distribution Gas Handling Instructions, the responsible supervisor will amend the document in Word and print, sign, and attach the revised Gas Handling Instructions to the original copy and return them in the project package.
- 2.3.3. If possible, an alternative gas handling plan shall be included with a package (12 inch or larger pipe, or 60 psig and greater) in case of the inability to achieve a "no gas flow" shut-in (potential bypassing valves or line stoppers).

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- 2.3.3.1. The sequence of activities in the gas handling plan shall be prioritized. Equipment to monitor and control the pressure shall be installed and operational prior to the system being pressurized and remain in place as long as the system is pressurized.
- 2.3.3.2. The gas handling plan shall require that the work site be left in a safe condition, and any out of service pipe or equipment be closed to gas flow and protected from accidental overpressure due to valve leak-by or other unexpected condition.
- 2.3.3.3. When any work is performed on, or which results in, an isolated pipeline section of 1000 feet or less being served by an active regulator station(s), valve and squeezing operations (both closure and opening) should be executed slowly (over a period of no less than one minute) in order to allow for transient conditions to be dampened, to avoid over-pressuring a short section of pipeline. This is particularly important where the upstream regulator station is served by pilot-operated gas regulators. Pipeline pressure should be noted and recorded after each of these operations.

Note: Although work plans and gas handling plans may support information conducive to a successful shutdown, it is the responsibility of the field supervisor to verify information is accurate before/after making a shutdown.

- 2.3.4. Supervision ensures that safety and gas system integrity are maintained during the Gas Handling Operation. Supervision reviews the Gas Handling Procedure with the crew before the start of the job. In addition, all Main/Line stop operations are performed under the direction of the responsible supervisor.
- 2.3.5. Review gas-handling procedures with the crew(s) performing the job operations mentioning key elements such as, but not limited to:
- Timeline of events
 - Maximum and minimum pressures
 - Operation sequence
 - Each member's responsibilities
 - Items of safety concerns
- 2.3.6. When work is performed by a contractor, the supervisor responsible for the gas handling operations confirms that the contractor understands the requirements concerning the installation of pressure gauges and/or EPM's, bypass connections, etc., as well as the purging and gas handling plans.

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Designated Company representative observes, directs or assists the contractor in conducting the gas handling and purging operations as needed.

- 2.3.7. Bypass district regulator stations shall be performed only under the direction of a qualified employee (such as a Meter and Regulation Technician #1). Gauges showing the district pressure are observed continuously while bypassing stations.

3. DEFINITIONS

- 3.1. **Blow-down** – Reduce line pressure by venting.
- 3.2. **Blow-down stack** – A vertical metallic pipe through which air or gas is vented.
- 3.3. **Dead-End** – An isolated pipeline segment that is downstream of a regulator station, valve or pressure control fitting and serves no customer gas demand.
- 3.4. **EPM (Electronic Pressure Monitor)** - a microprocessor-based, stand-alone, self-powered data recorder that measures gas pressure, gas temperature, case temperature, and internal battery voltages.
- 3.5. **Pressure gauge** – Instrument used to measure pressure.
- 3.6. **SMC** – Service to Main Connection.

Note: Install pressure gauges upstream and downstream of the portion of main to be shut-down. Pressure gauge stack is not used as a blow-down stack.

4. PROCEDURE

- 4.1. **Shut-Down of Supply, Feeder, Transmission, and Distribution-Operated Lines**
 - 4.1.1. Follow this procedure when supply lines, feeder lines, Transmission lines, and Distribution lines are shut down.
 - 4.1.2. A detailed written procedure shall be prepared for each shutdown that involves gas handling or fire control work. Exception: emergency situations.
 - 4.1.2.1. The sequence of activities in the gas handling plan shall be prioritized. Equipment to monitor and control the pressure shall be installed and operational prior to the system being pressurized and remain in place as long as the system is pressurized.
 - 4.1.2.2. The gas handling plan shall require that the work site be left in a safe condition, and any out of service pipe or equipment be closed to gas

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flow and protected from accidental overpressure due to valve leak-by or other unexpected condition.

- 4.1.3. Review plans with Gas Control, where applicable and pursuant to [GS CRMP6](#), *Gas Control Management of Change*, and [GS 223.0145](#), *Planning Shutdowns for Transmission and Storage*, when conducting transmission system shutdowns.
- 4.1.4. Efforts to limit inconvenience to the general public and governmental agencies shall be made as practical, without jeopardizing any items pertaining to safety. Such agencies may include:
- Air Pollution Control Districts
 - Police Departments
 - Fire Departments
 - Civil Aeronautics Board
 - Airfields
 - Highway or Street Departments
- 4.1.4.1. Notify the appropriate agencies of any planned blow-down or release of gas to the atmosphere and coordinate the work with their activities as necessary. See [GS 180.0085](#), *Valve Usage and Selection Guide* for location of blow-down valves.
- 4.1.4.2. High pressure projects that require gas blown to atmosphere will build time into the project to reduce methane consistent with safe operations and consider alternative potential sources of supply to reliably serve customers and maintain feasibility. Operating pressure should be reduced to the lowest operationally feasible level in order to minimize methane emissions before non-emergency venting of high-pressure distribution (above 60 psig), transmission, and underground storage infrastructure consistent with safe operations and whenever practicable, work should be bundled to prevent multiple venting of the same piping.
- 4.1.4.3. If possible, notify the public immediately adjacent to a blow-down site at least one day in advance of blow-down to avoid public concern about noise or odor.
- 4.1.4.4. Notify the Customer Services Department serving the affected area and arrange for customer notification in shutdowns that will curtail service. Commercial and Industrial meter accounts are notified of impact and or curtailment by means of the RER (Request for Engineering Review) and the various personnel working in the C/I Services group.

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4.1.4.5. Notify Customer Call Center, informing them of the areas that may be impacted.

Note: A minimum of 3 days notification to hospitals and schools (within 500') is required before starting non-emergency construction. See [GS 184.011](#), *Notification of Excavation and Construction Activities - Assembly Bill Number 1937/ PUC Code 955.5*

4.1.5. Action Required:

4.1.5.1. When closing any valve or conducting operations that produces a 'Dead-End' pipeline exiting a regulator station and the isolated pipe is not rated for the full-inlet pressure of the regulator station, an EPM is required on the dead-end portion when personnel are not available on site to monitor:

IMPORTANT: The monitoring of gauges needs to continuously be performed during squeezing operations, the application of pressure control fittings (line stoppers), closing of valves, the application of artificial load, and before the cutting of any pipe.

4.1.5.1.1. Install pressure monitoring equipment and monitor the pressure both upstream and downstream of any valve or regulator subject to manual operation or for any bypass operation.

4.1.5.1.1.1. If this requires the installation of gauges, make every effort to find a suitable location to install such in the area in which you are working. If this is not practical, employ personnel and/or gauges at locations in the nearest vicinity of your work location where pressures indicative of the pressure on each side of your valve can be monitored.

4.1.5.1.1.2. For work which holds the potential to affect a Distribution pressure district or supply line operation, use of EPM devices (either permanent or temporary) **will be** employed in coordination with Distribution Region Engineering.

4.1.5.1.1.3. Continually monitor pressures for no less than 15 minutes on each side of a valve after conducting such work, to ensure no system upset or destabilization has occurred.

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4.1.5.1.1.4. Similar pressure monitoring and work coordination should be made with Gas Control pursuant to [GS CRMP6](#), *Gas Control Management of Change*, and [GS 223.0145](#), *Planning Shutdowns for Transmission and Storage* when conducting transmission system shutdowns.

4.1.5.1.2. Close the inlet valves to the regulator run(s) in the station prior to downstream valve closure or pinching operation. The handling of regulator station facilities shall be performed only under the direction of a qualified employee (such as a Meter and Regulation Technician #1).

4.1.5.1.3. Monitor isolation section pressure for no less than 15 minutes after all valves are closed to ensure a secure shut-in.

4.1.5.2. Plan for Equipment Malfunctions.

4.1.5.2.1. Be aware that while our system is designed with the highest quality components and redundant safety systems, sometimes equipment operates imperfectly or is otherwise compromised. This potential should be considered in your work plans and execution.

4.1.5.2.1.1. Have a backup plan if a valve or regulator does not seal completely or other piece of equipment fails, and be aware of anything that looks out of the ordinary.

4.1.5.3. If unsure about a specific operation, plan or Gas Standard, seek guidance from your immediate supervisor or management team.

4.1.5.4. Know and understand the piping system you are working on, and the implications of valve operation on upstream and downstream pressures on each relevant pipeline section before beginning work.

4.2. Transmission Line Shut-Downs

4.2.1. Determine the effect of the Transmission Line shut-down on the distribution system and make plans for necessary distribution operations:

4.2.1.1. Make test shut-downs of distribution facilities when necessary to determine the effect of the transmission shut-down on distribution pressures.

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- 4.2.1.2. Assist the responsible supervisor, if required, in conducting shutdowns of transmission facilities for the same purpose.
- 4.2.1.3. Evaluate remedial measures (providing temporary facilities, more favorable shut-down schedule, etc.) when adverse effects are found.
- 4.2.1.4. Review the proposed transmission shutdown plan. When conflicts are encountered, work out a mutually satisfactory alternate schedule or arrangement with the responsible supervisor.
- 4.2.1.5. Make every effort to assist the responsible supervisor in reducing line pack prior to blow-down in order to minimize the amount of gas blown to atmosphere.
- 4.2.1.6. Plan and arrange for other distribution work that can be performed in conjunction with the shut-down provided the shut-down time is not unduly extended.
- 4.2.1.7. Plan for alternate supply and/or notification to customers affected by the shutdown.
- 4.2.1.8. Isolate distribution facilities from the transmission facilities being shut down. Perform other distribution work as planned only after confirmation of the shutdown is obtained from the responsible supervisor.
- 4.2.1.9. Observe progress of the transmission job, as necessary, to maintain operating control of the distribution system.
- 4.2.1.10. Return the distribution system to normal operation after notification from responsible supervisor.

4.3. Valve Verification

- 4.3.1. Prior to beginning a gas handling procedure, a physical inspection of all affected valves shall be conducted to verify the valve type and position match written gas handling plans, in addition to confirmation of the valves being operable. See [GS 184.16](#), *Valve Inspection and Maintenance – Distribution*. If the physical inspection reveals the valve type or position does not match the written gas handling plans, do not move forward with work until consulting with Engineering to determine the impact and to correct the written gas handling plans.

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4.4. **Pressure Gauge and Bypass Installations**

- 4.4.1. Pressure gauges are to be of a range that will allow the observer to detect minor changes in pressure. For example, use a 0-15 psi gauge when the operating pressure is 10 PSIG rather than using a 0-60 psi gauge. Prior to use, validate that gauges are accurate and in satisfactory working condition.
- 4.4.2. Where two or more pressurized pipelines are being connected, the pressure in each pipeline being connected must be determined prior to allowing gas to flow between the pipelines. Utilize pressure gauges and bypasses in distribution facilities shut down as follows.
- 4.4.3. Two-Way Feed:
 - 4.4.3.1. Where a two-way feed is indicated, verification is required. Install pressure gauges on each side of the portion of the main to be shut-down whether or not a bypass is used.
 - 4.4.3.2. The squeeze method of closing off a steel main does not allow it to be reopened immediately or throttled. Install an adequate bypass and gauges around the first squeeze, or the section to be squeezed, to prevent an accidental outage where a two-way feed is indicated but which may not exist.
 - 4.4.3.3. The designated supervisor specifies the type and size of the bypass based on pressure and load conditions. When requested, Planning will size the bypass. When working with Distribution facilities, Region Engineering will confirm Planning's bypass recommendation.
 - 4.4.3.4. The bypass requirement does not apply when a squeeze is used in combination with a valve or pressure control fitting when the valve or pressure control fitting is used first to stop the flow of gas through the main and the two-way feed is verified.
 - 4.4.3.5. On plastic pipe the squeeze method permits immediate reopening; therefore, a bypass may not be necessary.
- 4.4.4. One-Way Feed:
 - 4.4.4.1. Where a one-way feed is indicated, and a bypass is used, install pressure gauges upstream and downstream of the portion of main to be shut-down.
 - 4.4.4.2. Where a one-way feed is indicated, and service is not to be maintained downstream of the shut-down, install a pressure gauge on the upstream and downstream side of the closure to verify one-way feed is accurate.

4.4.4.3. Pressure Gauge Locations:

- 4.4.4.3.1. Install pressure gauges on existing service connections or pressure taps where they can be properly manned for pressure observation and immediate communication with the responsible supervisor in charge of the shut-down.
- 4.4.4.3.2. If there are no convenient service connections or pressure taps on the main, make mainline taps adjacent to the closure device for installing pressure gauges. Do not install pressure gauges on blow-down stacks, bypass, or bypass fittings.

4.5. Pressure Observations

4.5.1. Artificial Load

- 4.5.1.1. Install a blow-down stack or use an adjacent service and create an artificial load, to make certain that facilities to remain in service are adequately supplied. Reduce the main pressure two or more times by means of the stack. Determine that the main pressure returns to district pressure each time the stack is closed after blowing.

4.5.2. Blow-down Stack

- 4.5.2.1. The blow-down stack and related fittings must be of sufficient size to create a flow in the system which is large enough to verify that an adequate supply exists to serve the area being isolated.

4.5.3. Observe gauges to check the effects of operating valves, fittings, or squeeze closures.

- 4.5.3.1. When a valve or pressure control fitting is used, or a squeeze is made in plastic pipe, close it slowly so that any change in pressure may be observed before the main is completely shut-down.
- 4.5.3.2. After closure, observe the pressure for no less than 15 minutes to verify pressure has stabilized before proceeding with any piping changes.
- 4.5.3.3. If the pressure does not hold as planned, reposition the valve or stopper immediately to restore supply unless the pressure has dropped too low to maintain adequate pressure on customers' facilities.

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- 4.5.3.3.1. If the pressure has dropped too low, leave closed and handle as an outage. Do not re-pressure until all affected customers have been shut-off at the meter.

4.6. Temporary Gas Supply

- 4.6.1. If you have a need for portable Gas Pods and/or for portable manifolds (Christmas tree) please contact.

4.6.1.1. **During regular working hours 6:00 AM – 2:30 PM, Monday – Friday.**

- For Gas Pods: Call the Shipping Dispatcher at (562) 806-4222.
- For manifolds (Christmas tree): Call the Natural Gas Vehicles Group at (562) 806-4309.

4.6.1.2. **During off hours**

- The Logistics On-Call Supervisor through the Message Center at (213)-244-8900 during off-hours.

5. EXCEPTION PROCEDURE

(See [GS 182.0004](#), *Exception Procedure for Company Operations Standards*)

- 5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.
- 5.2. An exception from a standard shall not be allowed unless [GS 182.0004](#), *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

6. RECORDS

Not Applicable

7. APPENDICES

Appendix A

Distribution Gas Handling Template (*see next page*)

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Gas Handling Instructions
Standard 184.06 Gas Handling and Pressure Control
Standard 184.0350 Pressure Control - General

Click here to enter text.

Notification No. Click here to enter text.

Work Order No. Click here to enter text.

Pre- Construction Review/Approval		Construction Approval/ Verification	
	SIGN <small>(PRINT NAME BELOW LINE)</small>	DATE	SIGN <small>(PRINT NAME BELOW LINE)</small>
LPA			FTL OR FOSII
TSS			<p><small>NOTE: If Gas Handling changed from the Pre-Construction plan, modify the document to suit in Word, print – sign – date the revised document and attach it to the original instructions and return it with the project package. Check the box below if instructions are revised.</small></p> <p style="text-align: center;"><input type="checkbox"/> Revised Gas Handling Instructions</p>
FTL OR FOSII			

NOTE: Install a test fitting or utilize a suitable existing fitting to verify system pressure is 35 PSIG.

1.

Double click the icon below to save a copy of the Distribution Gas Handling template.



**Gas%20Handling%
20Template%20Distr**



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NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
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General Construction Requirements for Distribution Service Lines	SCG:	184.0060
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PURPOSE: To provide guidelines and requirements for distribution service installations, alterations and replacements for services operating at less than 20% Specified Minimum Yield Strength (SMYS).

1. POLICY AND SCOPE

1.1. Excavation shall comply with:

- [GS 191.0045](#), *Excavation Permits/Paving Repairs*
- [GS 184.0175](#), *Prevention of Damage to Subsurface Installations*
 - Notify Transmission a minimum of 48 hours prior to any construction when transmission lines are within 10' of the construction area
- [GS 184.0200](#), *Underground Service Alert and Temporary Marking*
- [GS 184.011](#), *Notification of Excavation and Construction Activities - Assembly Bill Number 1937/ PUC Code 955.5*
- [GS 184.0171](#), *Prevention of Sewer Lateral Intrusions and Damage*

1.2. Join polyethylene (PE) pipe and fittings using approved methods, fittings, tools, procedures. See [GS 182.0140](#), *Polyethylene Plastic Pipe - General Application Requirements*.

1.3. Join steel pipelines and fittings using approved welding procedures and appropriately rated fittings. See [GS 187.0055](#), *General Welding Requirements*.

1.4. For installation, alteration or replacement of any gas service, see [GS 187.0146](#), *Excess Flow Valve (EFV) - Installation and Operation*. For sizing requirements when installing EFVs, see [GS 182.005](#), *Service Pipe and Excess Flow Valve Sizing*.

1.4.1. If a curb valve was installed in lieu of an excess flow valve and the curb valve is replaced for any reason, first preference shall be the installation of an EFV that qualifies to serve the total load. See [GS 187.0146](#), *Excess Flow Valve (EFV) - Installation and Operation*. For installation requirements and location, see [GS 182.005](#), *Service Pipe and Excess Flow Valve Sizing*.

Note: For customer requested Excess Flow Valves on existing services, see [GS 187.0146](#), *Excess Flow Valve (EFV) - Installation and Operation*, and [GS 182.005](#), *Service Pipe and Excess Flow Valve Sizing*.

1.5. Send all defective or leaking materials that can be cut out to the Engineering Analysis Center (EAC), Pico Rivera, (SC723B). Leaking materials require a completed [Form 4050](#), *Leak Repair Order* attached. See [GS 223.0030](#), *Investigation of Failures on Distribution and Transmission Pipeline Facilities*, for the chain of custody.

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- 1.5.1. When replacing an EFV because of a suspected problem and/or failure:
- Document the incident on [FORM 5336](#), *EFV Incident Report*.
 - Route a copy of the completed [FORM 5336](#), *EFV Incident Report* to Gas Engineering at ML SC722S.
 - Route copies of the completed [FORM 5336](#), *EFV Incident Report* and the removed EFV to the M&E Group, Engineering Analysis Center, Pico Rivera, ML SC723.

1.6. To determine if gas handling is necessary, see [GS 184.06](#), *Gas Handling and Pressure Control*.

1.7. Construction tasks identified in [GS 191.0025](#), *Inspection and Scoring of Construction Work*, shall be **Independently Inspected** and captured by the “**Company Authorized Representative**” using the FACT form for Company crews and ISN form for Contractor crews. Personnel who performed the construction task (installing pipe, fusing, welding, etc.) requiring inspection shall not perform the **Independent Inspection**.

2. RESPONSIBILITIES AND QUALIFICATIONS

2.1. Only personnel qualified through **Gas Operations Training** or **Welding Training** may perform these operations See [GS 187.0180](#), *Qualification and Re-Qualification of Welders*, [GS 187.0181](#), *Qualification of Personnel - Polyethylene Pipe Joiners and* [GS 167.0100](#), *Operator Qualification Program*.

2.2. **Gas Operations Training** is responsible for ensuring the equipment and facilities used by an Operator for training and qualification of employees must be identical, or very similar in operation to the equipment and facilities which the employee will use, or on which the employee will perform the covered task.

2.2.1. The Applicant Installation Program does not qualify contractors for any phase of pressure control. Therefore, **applicant installers** are prohibited and shall not squeeze any PE pipe.

2.3. Only qualified personnel (**Company and Contractor**) shall perform pressure control operations on the gas system. See [GS 184.0590](#), *Pressure Control Qualification Requirements*, and [GS 167.0100](#), *Operator Qualification Program*.

2.3.1. All sources of ignition shall be eliminated in the immediate vicinity while pressure control or gas handling operations are in progress. No open flame, electrical spark or welding is permitted. See [GS 166.0025](#), *Prevention of Accidental Ignition of Natural Gas*.

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- 2.4. **Qualified Personnel** are responsible to visually inspect all pressure control equipment including squeezers prior to performing any pressure control operation. Do not use any damaged or defective equipment. Notify supervision if any defects are found.
 - 2.5. When contractor personnel are working on pressurized gas lines, it is the responsibility of **Field Operations Supervisor** to ensure that contractor personnel are qualified to perform these operations.
 - 2.6. **Contractors** shall be responsible for completing the “Small Pressure Control/Train the Trainer” course, administrating the training to their employees and ensuring their employees follow the procedures in the standards covered.
 - 2.7. **Company Field Employees** shall be responsible for adhering to company procedures and shall wear appropriate personal protective equipment during all duties performed. See Injury and Illness Prevention Program, [MANUAL IIPP.4](#), *Employee Responsibilities*.
 - 2.8. **Contractors** shall adhere to their Company Safety Procedures/Practices and are expected to comply with all applicable Federal, State and Local laws, ordinances and regulations to ensure the safety of their employees. See [GS 167.04](#), *Contractor Safety Program* and [SCG Contractors Safety Manual – Class 1 Contractors](#).
 - 2.9. **When applicable, Regions** shall be responsible to designate specific (trained and knowledgeable) supervisors to be responsible for gas handling operations within their respected areas.
 - 2.10. **Districts** shall be responsible for compliance and administering the implementation of this and all other Gas Standards related to or concerning distribution service line.
 - 2.11. **Gas Material - Gas Engineering** shall be responsible for administrating the development and coordinating the approval of material specifications that are used for distribution service lines (PE and steel pipe and fittings).
3. DEFINITIONS
- 3.1. **PE** – Polyethylene.
 - 3.2. **Substructures** - (Subsurface Installations) any belowground pipeline, conduit, duct, casing, wire or any other structure.

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- 3.3. **Tools-Type Order** - Indicates any instance where an employee is required to use tools (i.e. pneumatic and/or hand operated tools such as an Impacto Bar) to install, replace, or adjust fittings on the MSA (e.g., regulator change, leak orders, or anytime the service valve is turned on).

4. PROCEDURE

4.1. Customer Communication

4.1.1. When performing a construction activity on the customer's premises (e.g., an area that a customer may be the caretaker of, such as the parkway), communicate or attempt to communicate the following to a customer:

- All appropriate actions to be taken by the Company
- The type of work to be performed
- Any future follow-up actions
- Any and all other pertinent information

Note: Attempts to communicate with a customer are intended for orders that have an actual or physical address (indicating dwelling or habitation) associated with the worked being performed.

4.1.2. If the customer is not present or not available when leaving the job site:

- Leave [FORM 2001](#), *Customer Communications Tag – Distribution*.
 - Mark the appropriate box and/or write a brief explanation on **FORM #2001** describing the type of work performed and indicate whether a return visit is required.
- Contact Dispatch and request that a memo be added to the Customer's Account and make sure to describe the type of work performed. The memo shall include any and all future follow-up actions and any other pertinent information communicated to the customer.

4.1.3. Request **Supervision** assistance when a customer expresses concern(s) regarding the work to be performed or is not satisfied with the explanation provided, on the same day of the request (or immediately, if the situation warrants it).

Note: Employee shall disclose all pertinent and relevant communications made between customer and employee to their **Supervisor**.

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4.1.4. Provide no less than three (3) working days' notice to the administration of a School, Hospital and/or Registered Licensed Day Care Facility prior to undertaking non-emergency excavation or construction of a gas pipeline if the work is located within 500 feet of the School, Hospital and/or Registered Licensed Day Care Facility. See [GS 184.011](#), *Notification of Excavation and Construction Activities - Assembly Bill Number 1937/ PUC Code 955.5*, Include all of the following in the notification:

- The name, address, telephone number, and emergency contact information for the company.
- The specific location of the gas pipeline where the excavation or construction will be performed.
- The specific location of the gas pipeline where the excavation or construction will be performed.
- An invitation and a telephone number to call for further information on what the School, Hospital and/or Registered Licensed Day Care Facility should do in the event of a leak.

4.1.5. Planner Communication To Customer

- For applications where the service will terminate within a building/substructure, the Planner is to specify to the developer/customer during the initial field visit the specifications that will be required to install an AL Riser to avoid Prefabricated Risers, which are required to be cathodically protected. For all other meter room requirements, see [GS 182.0206](#), *Gas Meter room Requirements*.

4.2. Source of Supply

4.2.1. Use the closest gas main, when two or more are available, unless field conditions (e.g., traffic hazard, depth of main, medium pressure vs. high pressure, etc.) or economics (e.g., paving repair, etc.) dictate otherwise.

4.2.2. Use "Branch Service" installation procedure when a standard or branch service is the source of supply. See [GS 184.005](#), *Planning for Distribution Services*.

4.2.3. During the initial planning stage, contact and obtain permission from Transmission when a transmission line is the only source of supply. See [GS 182.0165](#), *Tap Requirements*.

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4.3. Route of Service

- 4.3.1. Install the service along the most practical route to avoid conflict with future construction. Install services in public property at right angles to the centerline of the street, whenever feasible.
- 4.3.2. Do not cross lot lines with a standard service or branch service without written right-of-way authorization. See [GS 106.0021](#), *Land and Right of Way Amendments*, and [GS 184.005](#), *Planning for Distribution Services*.

4.4. Substructure Clearances

- 4.4.1. Independently installed gas pipelines (gas only), when independently installed, shall be separated, where practical from electrical supply systems, communication, or other pipe systems or other foreign substructures, by a clearance of at least 12 inches when paralleling and by at least 6 inches when crossing.

Note: New gas pipelines inserted within, and utilizing as conduit, pipeline facilities installed prior to the effective date of this rule (01/01/2017) are exempt from the paralleling requirements of this paragraph but not the requirements related to crossings.

- 4.4.2. Concurrently installed (joint trench) gas pipelines, when concurrently installed with electrical supply systems, communication, other pipe systems, or other foreign substructures, shall be installed with the separation of 12 inches when paralleling and by at least 6 inches when crossing.

Note: The Gas Company will only participate in “Dry Utility” joint trench.

- 4.4.3. **Establish and maintain greater separation or an increased distance from the heat source for special conditions, such as hot oil, steam, and water lines.** Polyethylene pipelines must be installed with sufficient clearances, or must be installed, from any source of heat so as to prevent the heat from impairing the serviceability or the pipe. Contact **Gas Engineering** for possibility of installing insulating barriers between steam lines and steel and/or polyethylene pipelines in both paralleling and crossing installations. See [GS 182.0010](#), *Request for Pipeline Engineering Assistance*.

- 4.4.4. In all instances where the required separations cannot be maintained, it is the responsibility of the party last installing facilities to confer with the utility and ensure that the reduced separations do not adversely impact the integrity of the gas pipeline facilities, which includes any cathodic protection that may be applied to the gas pipeline facilities. See **Section 5** for Exception Procedures and requirements.

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4.4.5. All gas pipelines are to be installed with enough clearance from other substructures to allow for future maintenance and to protect against damage that might result from proximity to other structures. For additional trench specifications, see **Table 1**. For jobs with applicant provided trench, see [GS 184.010](#), *Planning Applicant Provided Trench Project* for additional information.

4.5. Excavations

4.5.1. Ensure and maintain that excavations, pavement cuts, and bore slots are no larger than necessary for safe and proper pipe installation(s).

4.5.2. Undercutting of pavement shall be permitted only when authorized or requested by the City, County, or State Inspector, and it is determined that it can be performed safely.

4.5.3. Shore or slope excavations as required. See [GS 223.0140](#), *Excavating, Shoring and Sloping*.

4.5.4. For direct burial excavations, excavate or attempt to excavate only when necessary, so that the pipe is installed on undisturbed and/or well-compacted soil and the backfill is free of materials that may damage the pipe and/or its coating.

4.5.5. Exercise caution and care when installing pipe using open trench or trenchless construction (e.g., boring or jetting into place) to prevent damage to the pipe, tracer wire, or pipe coating. See [GS 184.0170](#), *Trenchless Construction Methods*, [GS 184.0171](#), *Prevention of Sewer Lateral Intrusions and Damage*, [GS 184.0125](#), *Tracer Wire Installation for Polyethylene (PE) Pipe Installations*, [GS 186.0110](#), *Field Tape Wrapping Requirements* and [GS 184.0235](#), *Polyethylene (PE) Pipe Repair*, for maximum allowable damage to polyethylene pipe.

4.5.6. Bores

4.5.6.1. See [GS 184.0170](#), *Trenchless Construction Methods* and [GS 184.0171](#), *Prevention of Sewer Lateral Intrusions and Damage* for Trenchless Construction guidelines and requirements.

4.5.7. Casings

4.5.7.1. See [GS 182.0148](#), *Casing Assemblies - Plastic Carrier Pipe*, [GS 184.0100](#), *Inserting PE Pipe - Service Replacement*, [GS 182.0140](#), *Polyethylene Plastic Pipe - General Application Requirements*, and [GS 182.0080](#), *Casing Assemblies - Steel Carrier Pipe* for service casing requirements.

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4.6. Depth/Cover Requirements

4.6.1. Install all services to cover requirements of the permit issuing agency or the following, whichever is deeper. See **Table 1**.

TABLE 1

Normal Installation (Minimum Cover)	Public Property	Private Property
Steel Service (Operating above 60 PSIG)	24" *	20" *
Steel Service (Operating at 60 PSIG and below)	24" *	12" *
PE Service: <ul style="list-style-type: none"> • Below gutter flow line • Below the lowest point of the roadway where no curbs or gutters exist. • Between curb and property line unless subsurface installations necessitate less 	24" *	20" *
Service (Cross lot branch services. 30" min @ lot line)	N/A	30"
PE Service (In Steel Casing)	24"	12"
PE Service (In Plastic Casing)	24"	20"
Railroad Crossing	60" (below ground, plus ballast height)	60"
State Highway	42"	N/A
Navigable River, Stream, or Harbor	**Contact Pipeline Engineering	**Contact Pipeline Engineering

*30" cover is recommended for machine-excavated services.

All gas pipe installed in a **Navigable River, Stream, or Harbor must be installed with a minimum cover of 48" in soil or 24" in consolidated rock from the underwater natural bottom. **Contact Pipeline Engineering** for approval. See [GS 182.0010](#), *Request for Pipeline Engineering Assistance*.

4.6.2. Measure service depth/cover from proposed finished grade, rather than the existing, when street widening, or other improvement is proposed, and the new grade can be determined.

4.6.3. Notify supervision when depth/cover or other pertinent factors concerning knowledge of existing pipe may be compromised.

Note: Deviations are made and recorded only when sub-structures prevent minimum depth/cover from being attained. See **Section 5, Exception Procedures**.

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4.6.4. Shallow Service Installation

4.6.4.1. When subsurface installations make it necessary to install a service at less than the required depth/cover in public property, write on the service order in the Excavation Section, "**Request permit for shallow service**". Attach a sketch to the order illustrating size the and depth/cover of substructure; depth/cover and length of gas service; and depth/cover of the gas main.

4.6.4.2. Encase or reinforce shallow services to protect services from any anticipated external load and/or strain or potential damage.

4.7. **Bedding / Shading**

4.7.1. Properly support each service line on undisturbed and/or well compacted soil.

4.7.1.1. When native soil conditions (i.e., rock, hardpan, etc.) create a trench bottom that is unsatisfactory, add a minimum of 4" of approved bedding material free of rocks and debris, before installing pipe.

4.7.2. Shade all service pipe with a minimum of 12" of well compacted approved shade material.

4.7.2.1. A thorough inspection of the pipe is required before shading when non-pressurized pipe is exposed for a significant duration of time.

4.7.3. Shade all gas pressurized pipe or fittings before leaving job site.

4.8. **Backfilling and Compaction**

4.8.1. Use backfill around the pipe and ensure and verify that the area is free of materials (e.g. rocks, building material, debris, etc.) that may cause damage to the pipe and/or its coating. Comply with the requirements of the permit issuing agency and/or the responsible inspector regarding the use of backfill material. See [GS 184.0055](#), *Hand Backfill, Compaction Method*, [GS 184.0002](#), *Site Restoration Specification* and [GS 107.0400](#), *Dynamic Cone Penetrometer (DCP)*.

4.8.2. Compact the soil in compliance with the requirements of the permit issuing agency and/or the responsible inspector, see [GS 184.0055](#), *Hand Backfill and Compaction Method*.

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- 4.8.3. When equipment is used in the backfilling process, the pipe must be backfilled in a manner that prevents damage to the pipe and coating from the equipment.
- 4.8.4. Install and backfill each service line with the intent to minimize anticipated piping strain and/or external loading.

Note: Do not pneumatically compact directly over PE pipe or fittings with less than 12” of cover and Do not hydra-hammer over PE installations with less than 24” of cover. Do not hydra hammer over tie-ins.

4.9. Material

4.9.1. PE Pipe/Material

- 4.9.1.1. To properly store, transport, and handle all PE pipe and PE material, see [GS 184.0447](#), *Handling and Storage of Polyethylene (PE) Materials*.
- 4.9.1.2. For a temporary bypass or temporary situation, all PE pipe and PE material installed above ground shall meet the above ground exposure requirements in [GS 182.0140](#), *Polyethylene Plastic Pipe – General Application Requirements*.
- 4.9.1.3. Cap, plug, or otherwise seal all PE pipes prior to and until the installation is complete.

4.9.2. Steel Material

- 4.9.2.1. Protect pipe and protective coating from damage using reasonable care when loading, transporting, unloading and installing pipe.
- 4.9.2.2. Install only Company approved steel pipe and fittings of adequate design pressure. See [GS 182.0125](#), *Steel Service Design – 60 PSIG or Less*.

4.9.3. All Material

- 4.9.3.1. Only Install company approved pipe and fittings of adequate design and pressure rating. See [GS 180.0001](#), *Material Usage and Selection*.
- 4.9.3.2. For the chain of custody, see [GS 223.0030](#), *Investigation of Failures on Distribution and Transmission Pipeline Facilities*.

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4.9.3.3. For casing used as conduit to facilitate the installation of gas services in residential and commercial subdivisions, see **Section 4.5.7** above.

4.10. Inspection

4.10.1. PE Pipe/Material

4.10.1.1. Inspect all PE pipe, pre-tested PE pipe, PE fittings, AL risers, transition fittings, and PE excess flow valves prior to installation. Do not use any pipe that has kinks, dents, gouges, cuts or other imperfections, which could impact its serviceability. See [GS 184.0235](#), *Polyethylene (PE) Pipe Repair*.

4.10.1.1.1. Verify the manufacture dates of PE pipe, pre-tested PE pipe, PE fittings, AL risers, transition fittings, and PE excess flow valves are NOT out of compliance prior to installation. See [GS 184.0447](#), *Handling and Storage of Polyethylene (PE) Materials*.

4.10.1.2. The Fuser shall visually inspect all PE pipe and fitting joints.

4.10.1.2.1. The Fuser (i.e. the authorized individual exercising dominion and control of the fuse) is responsible for cutting out any and all defective fusions and repeating the fusion process, as necessary.

4.10.1.2.2. All visual inspections of completed fusions must meet the Visual Inspection Characteristics and Criteria for completed fusions identified in [GS 187.0115](#), *Fusion Requirements for Polyethylene Pipe*.

4.10.2. Steel Pipe

4.10.2.1. Inspect all welds in compliance with Company procedures. See [GS 187.0175](#), *Inspection and Testing of Welds on Company Steel Piping*.

4.10.2.2. Inspect steel pipe for protective coating damage and repair as necessary. See [GS 186.0100](#), *Approved Protective Coatings for Below Ground Corrosion Control*.

4.10.3. All Pipe(s) Inspection

4.10.3.1. Inspect all pipes for visible defects before and during installation to ensure and verify that the pipe(s) have not sustained any damage that could impact its serviceability.

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- 4.10.3.2. Ensure and verify all pipe ends are clean and free from any and all defects before initiating any joining procedure.
- 4.10.3.3. Ensure and verify that the inside of the pipe(s) are clean and free of debris and foreign material before joining it to another length of pipe.
- 4.10.3.4. Align pipe and fittings to avoid lateral strain and/or tension.
- 4.10.3.5. Send all PE failures that can be cut out to the Engineering Analysis Center (EAC), Pico Rivera, (SC723B), with a copy of the completed [Form 4050](#), *Leak Repair Order*. For the chain of custody, see [GS 223.0030](#), *Investigation of Failures on Distribution and Transmission Pipeline Facilities*.

4.11. Pipe Aligning and Assembly

- 4.11.1. Weld all steel pipes in accordance with [GS 187.0056](#), *Welding Field Guide*, and [GS 187.0055](#), *General Welding Requirements*.
- 4.11.2. Heat fuse or join all PE pipe connections in accordance with [GS 187.0115](#), *Fusion Requirements for Polyethylene Pipe*.
- 4.11.3. Verify size, type and location of gas main prior to installing service to main connections to prevent accidental tapping of casings or foreign substructure installations. See [GS 187.0210](#), *Service-Connections to Steel Pipelines*.
- 4.11.4. Install PE pipe so its natural curve lies on a smooth trench bottom free of rock and debris.
- 4.11.5. Provide appropriate end closures when stubbing services, see [GS 182.0085](#), *Pipe End Closures*.
- 4.11.6. For PE pipe minimum bending radius, see [GS 182.0140](#), *Polyethylene Plastic Pipe – General Application Requirements*.

4.11.7. PE Pipe End Joining - Selection Guidelines

- 4.11.7.1. **Table 2** is intended to assist the joiner and/or planner in selecting the optimum PE pipe end joining technique based on pipe size, joint requirements and joining circumstances.

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Table 2

Pipe Size	Joining Circumstances			
	Socket	Butt	Electro	
½"	1	N	N	Above ground , one or both pipe ends have lateral in-line freedom of movement
1"	1	N	2	
2"	2	1	3	
3" & Over	N	1	2	
½"	1	N	N	Within excavation , one or both pipe ends have lateral in-line freedom of movement
1"	1	N	2	
2"	2	1	3	
3" & Over	N	2	1	
½"	1	N	N	Within excavation , both pipe ends lack lateral in-line freedom of movement
1"	2	N	1	
2" & Over	N	N	1	

Fusion Selection Codes:

- 1 = First Preference
- 2 = Second Preference
- 3 = Third Preference
- N = Not Used
- N/A = Not Applicable

4.12. Testing

4.12.1. Test all newly installed, repaired, or reinstated piping in compliance with [GS 184.0150](#), *Leak Testing of Distribution Piping with MAOP <= 60 PSIG* and/or [GS 182.0170](#), *Strength Testing - High Pressure Pipelines and Facilities*.

4.13. Squeezing

4.13.1. PE Pipe

4.13.1.1. For squeezing PE pipe, see [GS 184.0340](#), *Squeezing Polyethylene PE Pipe - 1/2" Through 8"*.

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4.13.2. Steel pipe

4.13.2.1. For squeezing steel services, see [GS 184.0315](#), *Squeezing Steel Pipe 1-1/2" and Smaller Powell® S-4H and S-3A Pipe Squeezer* or [GS 184.0320](#), *Squeeze Steel Pipe 2 inch with Regent® Pipe Squeezer*.

4.14. Purging

4.14.1. After tapping service to main connection, purge service with gas to remove air and possible debris from piping. See [GS 182.0160](#), *Purging Pipelines and Components*, [GS 182.0162](#), *Purging and Locking Service Risers*, and [GS 166.0025](#), *Prevention of Accidental Ignition of Natural Gas*.

4.15. Heaters

4.15.1. Heaters used for PE fusions are calibrated as per [GS 184.0130](#), *Polyethylene Heater - Temperature Measurement and Adjustment*.

4.16. Prohibited Locations for PE Pipe

4.16.1. All PE pipe(s) are **prohibited** from any and all activity:

- Above ground, except on bridges through a casing or temporary situation.
- No wet (water/sewer) utilities in joint trench.
- In vaults
- Near steam lines, hot water lines or any other source of heat.
- Under any structures such as buildings, patios, carports or breezeways; except for isolated cases that are designed and approved by **Engineering**.
- Under electric facilities, such as but not limited to, splice boxes, transformer pads, etc.
- Where pipeline(s) can reasonably be subject to natural hazards, exposure to heat or excessive stresses, or significant buoyant force. See **Section 4.17** below.

Note: **Region Planning and Engineering** shall approve all PE pipe installations in and/or on bridges. See [GS 182.0090](#), *Designs for Pipelines in Bridges*.

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4.17. Protection from Hazards

- 4.17.1. Ensure all necessary and practical steps are taken to protect the pipeline from future natural hazards such as, washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads when installing services. In addition, ensure all necessary and practical steps are taken to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations etc.
- 4.17.2. Contact **Region Engineering** if any of the following conditions are found in the pipeline system, such as, but not limited to:
- Where pipelines are exposed due to erosion.
 - Where pipelines may be crossing a seismic fault.
 - Where pipelines cross areas which are normally under water or subject to flooding (such as lakes, bays, swamps and river crossings) and may require anchorage to prevent flotation.
 - Where pipelines are in unstable banks and bed locations.
- 4.17.3. Protect all aboveground services from any and all potential damage by vehicular traffic or other causes by placing the service at a safe distance from traffic or by installing barricades.
- 4.17.4. Protect all PE services temporarily installed aboveground from deterioration and external damage. PE services temporarily installed aboveground shall not be used to support external loads.
- 4.17.4.1. Contact **Pipeline Engineering** to initiate corrective actions if any of the above conditions are found in the existing pipeline system and/or the pipeline system being constructed.
- 4.17.5. Install pipe with sufficient clearances and/or insulation from any and all sources of heat to prevent impairing the serviceability of the pipe.
- 4.17.6. Areas that may be subjected to excessive external stresses and external loading, i.e., vehicular traffic, or construction activity, shall be reinforced to protect installed pipe from potential damage.

4.18. Installation of Belowground Services Under Buildings

Note: Install belowground medium pressure services under buildings only when there is NO other alternative.

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4.18.1. Install services using the following provisions:

- The belowground service pipe installed under a building must be encased and extend beyond the building dimensions by 2' at the open end of the casing.
 - The casing must meet the standup test requirements, so the casing is gas tight. See [GS 184.0150](#), *Leak Testing of Distribution Piping with MAOP <= 60 PSIG*.
- The space between the casing and service pipe is sealed with Duxseal and plastic tape to prevent potential gas migration into the building if leakage occurred.
- The riser end of the casing is normally sealed; leaving the opposite end open.
 - If the casing is sealed at both ends, install a vent line, extending from the casing to a point above ground where gas would not be a hazard. See [GS 182.0080](#), *Casing Assemblies - Steel Carrier Pipe*, and [GS 182.0148](#), *Casing Assemblies - Plastic Carrier Pipe*.

CAUTION: Do not install belowground high-pressure services under buildings.

4.19. **Installation of Services into Buildings**

Note: Install medium-pressure services into buildings only when there is NO other alternative. If unavoidable, contact **Engineering** to handle the situation.

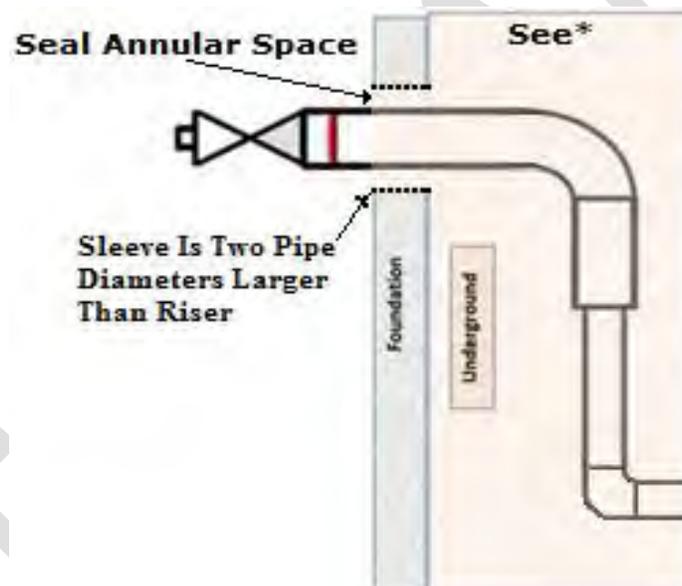
4.19.1. If there is no other alternative, then install services using the following provisions:

- The piping design and associated supports shall be reviewed and approved by Pipeline Engineering to ensure design specifications are acceptable. See [GS 182.0010](#), *Request for Pipeline Engineering Assistance* and [GS 182.0206](#), *Gas Meter room Requirements*.
- When PE pipe is used for service piping that terminates within a building:
 - The preferred installation method for services into a building is a PE service utilizing an AL Riser to penetrate the structure. If installation utilizing an AL Riser is not feasible, steel pipe must be used for the portion that enters the structure and must be cased and sealed (see [GS 186.0005](#), *Cathodic Protection - Mixed Piping System*) also described in **Section 4.18 above**.
 - To protect the PE pipe from damage, a steel offset between the transition fitting and the building is recommended or:

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- That portion of steel service located within an underground garage or basement must be rigidly secured but does not require encasement.
- When using an AL riser for the portion that enters the structure
 - The orientation of the riser going through the wall is very important as to determining support.
 - The AL riser bend is below ground, thus supporting any torsional movement. The steel casing will support against shearing. See **Figure 1** or **Figure 2**:



*Vertical Unistrut support(s) are required in conjunction with Horizontal Unistrut supports when using an AL riser to ensure the load is equally distributed and no stress or weight is carried by the AL riser. Vertical supports should be placed as close as practicable to the elbow transitioning the riser from the vertical position to the horizontal position.

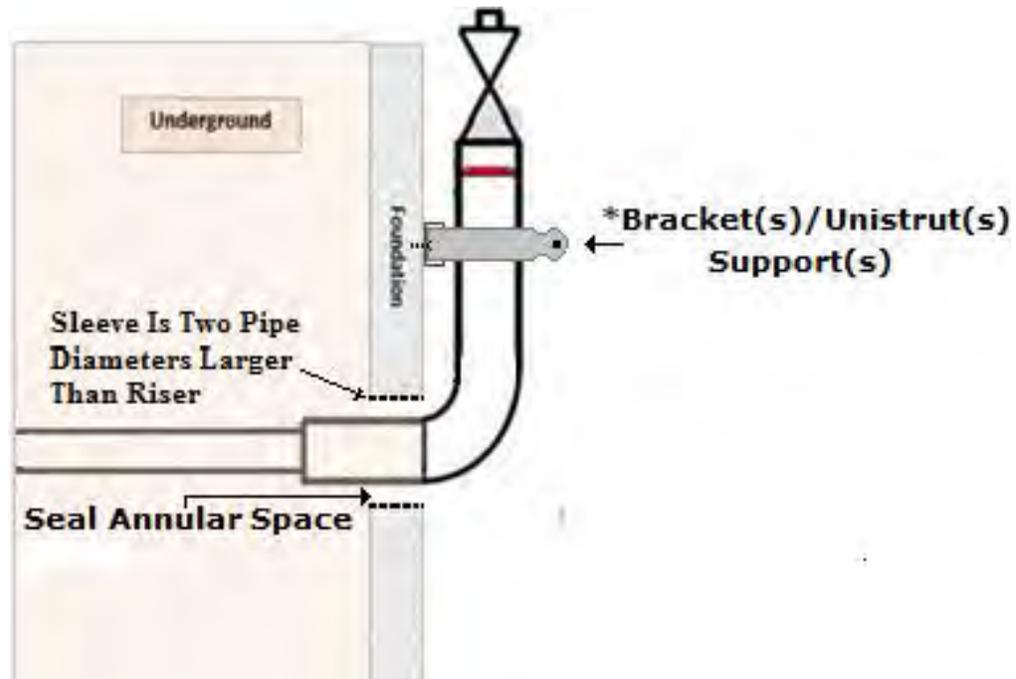
FIGURE 1

Note: In **Figure 1** and **Figure 2** it is important to have the red line exposed and not in the wall. The riser casing must also extend outside of the wall below ground. This also is an important step. Make sure to seal the inside wall and if sealing the outside, run a vent line out.

- The AL riser bend is in the building. Riser needs to be Bracketed/ supported inside the bldg. against the foundation wall (*). The steel casing will support against shearing. See **Figure 2**.

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*Vertical Unistrut support(s) are required in conjunction with Horizontal Unistrut supports when using an AL riser to ensure the load is equally distributed and no stress or weight is carried by the AL riser. Vertical supports should be placed as close as practicable to the elbow transitioning the riser from the vertical position to the horizontal position.

FIGURE 2

- That portion of steel service located within an underground garage or basement must be rigidly secured but does not require encasement.
- When steel pipe is used for service piping that is to terminate within a building, a casing must be installed through the foundation wall and extend into the building to a normally usable and accessible part of the building.
- Seal the riser end of the casing with Duxseal and plastic tape and leave the opposite end of casing open to prevent leakage into the building. See [GS 182.0080](#), *Casing Assemblies - Steel Carrier Pipe*.
- Steel used as casing (excluding AL Risers) must be Cathodically Protected in accordance with [GS 186.09](#), *Cathodic Protection - Casings*. All segments of submerged Steel Carrier pipe must be Cathodically Protected in accordance with [GS 186.005](#), *Cathodic Protection - Mixed Piping System*. A Cathodic protection Test Station (ETS) as shown in [GS 186.09](#), *Cathodic Protection - Casings* must be installed external to the building for both the steel casing and carrier pipe and accessible for

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routine monitoring.

- The service line must be protected against external damage.
- Above ground piping must terminate at an approved meter location and meet requirements for service valve installation. See [GS 185.0001](#), *Meter Locations*, and [GS 184.0090](#), *Valve Selection and Installation – Services*.

Note: Do not install high-pressure services (greater than 60 PSIG) within buildings.

4.20. Existing Services Under Buildings

4.20.1. When work is to be performed on a service and any portion of the uncased service is found belowground and under a building, that portion of the service must be altered or encased.

4.21. Drilling Foundations

4.21.1. Drill holes at a minimum of 12” from any opening and no less than 4” from the top of the foundation to prevent cracking of the foundation walls.

4.22. Extending Beyond the Main

4.22.1. Do not extend service beyond the end of the main ("leading the main"), unless one of these situations exists:

- Future main extension is improbable or unnecessary because of physical barriers.
- Present facilities are adequate to serve any future customers.
- Installing a service diagonal to the main can eliminate a main extension of 50’ or less. **Distribution Technical Services** must authorize these service routes after considering future growth potential.

4.23. Mobile Home Services

4.23.1. Use the following guidelines when planning new business services for mobile homes:

- Delay installation until the liquid waste disposal system, concrete patio, and/or the carport slabs are installed. When practical, do not install service piping under concrete slabs or paved driveways that may be directly under the designated area for a mobile home.
- Obtain from the owner a plot plan of the property including location, dimensions of the coach in relation to the property line and the gas stub-

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out location and whether the mobile home is to be placed on a "foundation system" or not.

- Inform the owner that the stub-out locations shown on the plot plan are final and any desire to relocate the service after the service has been installed would be at the owner's expense.

4.24. Service Discrepancies

4.24.1. Installation crews are expected to meet deadline dates to avoid customer inconvenience. Contact supervision whenever the following service discrepancies occur:

- Customer deems meter location as unsatisfactory. See [GS 185.0001, Meter Locations](#).
- Negotiate a change order to be signed by the customer if the method of installation or pipe footage is different from what was planned and would result in higher cost to the Company.

4.25. Marking Service Locations on Curb

4.25.1. Chisel a "G" on the top of curb or sidewalk where service crosses the curb or sidewalk.

Note: Not all entities allow this practice. Before chiseling a "G" on the top of curb or sidewalk, check with your local inspector.

4.26. Service Converted to Main-Identification

4.26.1. Install two harness rings on the service shut off when a portion of the service is converted to main. (Example: main extension installed in parkway from an existing service to avoid cutting pavement.) See [GS 223.0415, Pipeline and Related Definitions](#).

4.27. Cathodic Protection

4.27.1. For steel pipe installation and cathodic protection (CP), see [GS 186.0002, Design and Application of Cathodic Protection](#).

4.27.2. For existing steel services that will be tied over to a PE main as the result of a main replacement, see [GS 186.0005, Cathodic Protection - Mixed Piping System](#).

4.28. Tracer Wire Installation

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4.28.1. Follow the installation guidelines for locating wire when installing, replacing, and/or repairing PE piping, see [GS 184.0125](#), *Tracer Wire Installation for Polyethylene (PE) Pipe Installations*.

4.29. Curb Meter Vaults

Note: Discourage the installation of new business curb meter vaults and only install them if there is no other alternative and all other possible meter locations have been explored. The Project Manager shall approve all meter and service regulator installations in curb meter vaults or other subsurface installations.

4.29.1. Install or extend all existing services in curb meter vaults to an acceptable aboveground location agreed to by the property owner and the Company subject to one or more of the following conditions:

- Routine service replacements initiated by leakage.
- Service replacement and/or tie-overs involved in main replacements due to maintenance, franchise or street improvement projects.
- Repair of broken curb meter vaults or MSA parts.
- Pedestrian hazard, MSA leakage, regulator malfunction, pressure problems, chronic flooding problems, and/or repeat call-backs for service.
- Service alterations due to customer request or houseline leakage.

Note: All work performed due to customer's request-is negotiated as per [GS 191.0090](#), *D-Ticket - Collectible Work Agreements*.

4.30. Warning Mesh Installation

4.30.1. For pipelines operating at greater than 60 PSIG, see [GS 184.0050](#), *General Construction Requirements for Distribution Mains for warning mesh requirements*.

4.31. Material Traceability

4.31.1. **For pipelines operating at greater than 60 PSIG**, see [GS 182.0056](#), *Material Traceability for High-Pressure Systems*.

- To ensure compliance with “Quality Practices” and “Rejection of Defective” Materials.
- For traceability when materials are altered or segmented in the field.
- To ensure material batch information traceability is captured during installation.

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5. EXCEPTION PROCEDURE
(See [GS 182.0004](#), *Exception Procedure for Company Operations Standards*)
 - 5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.
 - 5.2. An exception from a standard shall not be allowed unless [GS 182.0004](#), *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

6. OPERATOR QUALIFICATION COVERED TASKS
(See [GS 167.0100](#), *Operator Qualification Program, Appendix A, Covered Task List*).
 - **Task 01.01.** - 49 CFR 192.319 - Installing Transmission Pipelines and Distribution Pipelines in a Ditch.
 - **Task 01.02.** - 49 CFR 192.327 - Maintaining minimum cover over pipelines.

7. RECORDS
 - 7.1. All records will be noted and retained on appropriate work orders and As-Built drawing.
 - 7.2. Retain original documents in file in compliance with the Corporate Records Retention Schedule.
 - 7.3. Material Traceability
 - 7.3.1. **For pipelines operating at greater than 60 PSIG**, see [GS 192.0026](#), *Records Management for High Pressure Project Closeout*.
 - To ensure compliance with High Pressure Project Reconciliation Closeout and Turnover.
 - For documentation and traceability.

8. APPENDICES
Not Applicable.



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NOTE: Do not alter or add any content from this page down; the following content is automatically generated.

Brief: The policy was revised to add clarity for cover below Railroad crossings in Table 1. Removed policy in policy verbiage in section 4.9.1. Added additional reference to section 4.12 for testing pipelines. Update Hyperlinks.

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Purging Pipelines and Components	SCG:	182.0160
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PURPOSE This gas standard provides the policy and procedures for safely purging natural gas pipelines. All company and contract employees shall follow these guidelines when purging pipeline systems.

1. POLICY AND SCOPE

- 1.1. Pipelines are purged to prevent the presence of a combustible mixture of gas and air. Failure to abide by the requirements of this Gas Standard may result in serious or catastrophic consequences.
- 1.2. This procedure **does not include** purging operations that utilize air movers. For these purges, see [GS 187.0103](#), *Purging Pipelines Using Air Movers For Cold Tie Operations*.
- 1.3. The Purging Operation Supervisor shall conduct a meeting, prior to a purging activity, to ensure all personnel engaged in purging operations understand the procedures involved. The Purging Operation Supervisor shall ensure that all employees and contractors involved in purging understand the potential hazards of improper operation. If changes in operations occur, all personnel will be informed of the changes before proceeding.
- 1.4. Limit access to the work area of the purging operation to only those persons who are necessary to perform the activity, keeping all-non-essential personnel and the public clear of harm's way.
- 1.5. All personnel directly involved in purging shall be outfitted with personal protective equipment including ear and eye protection, gas monitors, gloves, head protection, etc.
- 1.6. Gas shall be vented into the atmosphere without hazard to workers, public and property.
- 1.7. Considerations must be given to the public with regard to objectionable noise and odor as well as any noise or pollution abatement requirements. Such considerations may include the use of noise suppression equipment, notification of law enforcement, Fire Department and Air Pollution Control District.
- 1.8. All parts and equipment involved in the purging operation shall be in proper working condition and are visually inspected before use.
- 1.9. Adequate visual and/or radio communications shall be established between all work locations including the injection and venting points.
- 1.10. Fire extinguishers are manned and readily available at injection, vent, and upwind of the vent location.

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- 1.11. When purging out-of-service follow procedures stated in [GS 182.0032](#), *Blowdown Time, Sizing, and Volume Calculations* and [Form 3466](#), *Reporting of Gas Blown to Atmosphere* to account for the gas lost to atmosphere.
- 1.12. Any deviation from this Gas Standard shall be reviewed and approved by **Gas Engineering - Pipeline Engineering**.

2. RESPONSIBILITIES AND QUALIFICATIONS

- 2.1. Only Company personnel qualified through Gas Operations Training may perform these operations. See [GS 167.0100](#), *Operator Qualification Program*.
- 2.2. **Distribution Region, Transmission District or Storage Facility Planning Office** Purging Planner, or the District Operations Manager, shall be responsible for preparing the written purging procedures. See **Section 5.4** for further requirements.
- 2.3. **Region, District, or Storage representatives, as applicable**, are responsible to designate **trained and knowledgeable** supervisors to be responsible for gas handling operations, including purging, within their respected areas.
- 2.4. **Gas Operations Training and Contractors** are responsible for ensuring the equipment and facilities used for training and qualification of employees must be identical, or very similar in operation to the equipment and facilities which the employee will use, or on which the employee will perform the covered task.
- 2.5. **Company field employees** are responsible for adhering to Company procedures and shall wear appropriate personal safety equipment during all duties performed. See Injury and Illness Prevention Program [Manual IPP.4](#), *Employee Responsibilities*.
- 2.6. **Contractors** are responsible for adhering to their Company Safety Procedures / Practices, and are expected to comply with all applicable Federal, State and Local laws, ordinances and regulations to ensure the safety of their employees. See [GS 167.04](#), *Contractor Safety Program* and *SCG Contractors Safety Manual – Class 1 Contractors*.



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- 2.7. The Purging Operation Supervisor shall verify that all sources of ignition have been identified and eliminated prior to purging gas, performing pressure control operations or bypassing meters. See [GS 166.0025](#), *Prevention of Accidental Ignition of Natural Gas*.

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- 2.7.1. **Field Employees** are responsible for ensuring that an approved fire extinguisher (minimum 40 BC) is readily accessible and its location is known at the work site.
- 2.7.2. **Qualified Operators** are responsible to visually inspect all pressure control equipment prior to performing any pressure control operation. Do not use any damaged or defective equipment. Notify supervision if any defects are found.

3. DEFINITIONS

- 3.1. **Blow-down** - To reduce pipeline pressure to atmospheric pressure by venting gas to atmosphere.
- 3.2. **Cursory Odor Sniff Test** - A quick release of natural gas into the atmosphere that is sniffed to determine if odorant is detectible by smell.
- 3.3. **Direct Purge** – The act of either directly purging gas with air or air with gas at high velocities **without** a nitrogen slug.
- 3.4. **Indirect Purge** – The act of either purging from gas to air or from air to gas with a nitrogen slug between the air and gas to prevent the formation of a combustible mixture.
- 3.5. **Purge** - The act of removing all the air from a pipeline and replacing it with natural gas or removing all the natural gas from a pipeline and replacing it with air.
- 3.6. **Purging out of service** – (*Gas to Air/Nitrogen*) The process of replacing natural gas content in a pipeline with air/nitrogen by injecting air or nitrogen at sufficiently high flow rates.
- 3.7. **Purging into Service** – (*Air/Nitrogen to Gas*) The process of replacing air or nitrogen content in a pipeline with natural gas by injecting natural gas at sufficiently high flow rates.
- 3.8. **Purging Operation Supervisor** – The designated trained and knowledgeable supervisor responsible for gas handling operations, including purging.
- 3.9. **Slug** – As it relates to this standard, is a quantity of nitrogen gas injected between the gas and air during an indirect purge. The slug moves through the pipe as a distinct mass to prevent mixing of the gas and air.
- 3.10. **Total Displacement Purge** – The act of purging from gas to air or air to gas by injecting an amount of nitrogen slightly greater than the entire internal volume of the pipeline segment or facility to be purged.

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- 3.11. **CGI** – Combustible Gas Indicator
- 3.12. **BC** – Fire extinguisher rating effective for flammable liquid fires and “live” electrical equipment.
- 4. REQUIREMENTS PRIOR TO PURGING
 - 4.1. **ISOLATION** - Completely isolate the piping segment to be purged from the system.
 - 4.1.1. Isolation may be accomplished by one or more methods including the use of blind flanges, closing valves, placing blanking discs between flanges, pressure control fittings or physically disconnecting laterals or other sources of gas.
 - 4.1.2. Squeezing of PE pipe may be an acceptable means of isolation for purging. Only Company approved squeeze tools shall be used. *See [GS 184.0340, Squeezing Polyethylene \(PE\) Pipe – 1/2" Through 8"](#).*
 - 4.1.3. If valves are used to isolate the section to be purged from the pressurized system, they should be verified to stroke properly and not to leak.
 - 4.1.4. A thorough physical check shall be made to ensure that isolation is prepared as planned and free of leakage prior to the start of the purging operation.
 - 4.2. **NITROGEN** - When using nitrogen as a separating medium (slug) or for Total Displacement Method, practicality, availability and economics determine whether to use cylinders (bottles) or a tank truck. A tank truck is normally the less costly option when a large volume of nitrogen is required.
 - 4.2.1. Standard cylinders typically have 250 standard cubic feet (scf) of nitrogen at 2265 psig.
 - 4.2.2. If an Indirect Purge is required, use **Table A3** in Appendix A to determine the minimum number of cylinders required. If the use of a nitrogen truck is desired, such as when large volumes are required, see **Table A5** in Appendix A to obtain required nitrogen volumes.
 - 4.2.3. If a Total Displacement Purge is required or desired, use **Table A4** in Appendix A to determine the minimum number of cylinders required for a Total Displacement Purge.

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5. PROCEDURE

5.1. Selection of Purging Method

5.1.1. **Purging Operation Supervisor** must understand and approve the written procedures to provide a safe and successful completion of the purging operation. See **Section 5.5** for further details about the written plan. **Using Table 1 below, select the proper purging method based on the combination of pipe diameter and length of the segment to be purged.**

Diameter (in)	Length (ft)	Purging Method
$D \leq 4$	Any	Direct (Section 5)
$D \geq 6$	$L < 500$	Direct (Section 5)
$D \geq 6$	$L \geq 500$	Indirect (Section 7)

Table 1

The Total Displacement Method (**Section 3.10**) shall be used when:

- A potential hazard exists due to the presence of liquids or solids
- A potential hazard exists due to a complex piping situation, such as with stubs, or in compressor and regulator stations
- Permanently abandoning a transmission line or main that is not free of liquids or solids, or if required by the permitting agency. See [GS 184.0085](#), *Abandonment or Inactivation of Gas Distribution Pipelines*, or [GS 223.0130](#), *Abandonment, Conversion and Reinstatement of Transmission Pipelines*.

5.2. Sources of Ignition

5.2.1. All possible sources of ignition shall be eliminated in accordance with [GS 166.0025](#), *Prevention of Accidental Ignition of Natural Gas*.

5.2.2. When purging, especially with old piping, it shall be kept in mind that purging removes only gaseous or volatile materials. Undetected liquid or solid combustibles can be ignited by sparks carried back into a purged pipeline when it is cut. Take necessary precautions to ensure removal of difficult to detect combustibles.

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- 5.2.3. Consider purging with the Total Displacement Method with nitrogen if the presence of liquids or solids exists. See **Section 3.10** for definition of Total Displacement Purge.
- 5.2.4. Care shall be taken to avoid static electrical discharge before, during and after purge by grounding all machinery and equipment where static electricity might accumulate. Pipelines are bonded or grounded before purging, cutting, or disconnecting in accordance with [GS 184.0230](#), *Bonding Steel Mains and Services*. Before severing or disconnecting a steel pipe, a bond wire must be attached to the metallic pipe at two points to provide a connection across the proposed severance or disconnection which connects both sides of the remaining pipe. For purging Polyethylene (PE) pipe, see [GS 166.0025](#), *Prevention of Accidental Ignition of Natural Gas*.

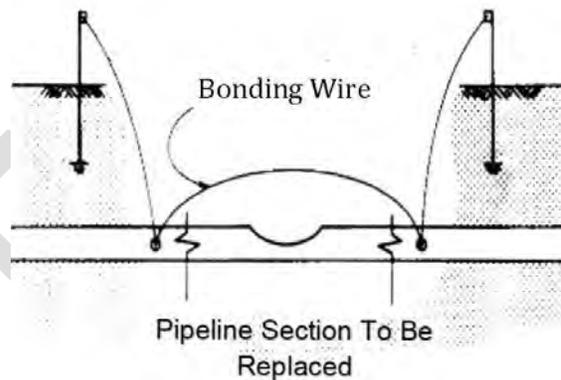


Figure 0. – Bonding wire placed across proposed severance or disconnection

- 5.2.5. Cathodic protection rectifiers shall be turned off.
- 5.3. **Venting**
- 5.3.1. See **Table A1** for vent stack sizing.
- 5.3.2. The steel vent stack should consist of a full opening tap in the pipeline to be purged.
- 5.3.3. When a vent valve is used, it shall be full opening.
- 5.3.4. When selecting venting locations, care is taken to prevent accidental ignition during purging operations. Avoid venting under or in close proximity to

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overhead power lines, per [GS 182.0161](#) – *Purging Operations – Minimum Distance Between Purging Stack and Ignition Sources*.

5.3.5. Never discharge purging medium through a plastic vent pipe.

5.3.6. Any project that requires gas blown to atmosphere will build time into the project schedule to reduce methane consistent with safe operations and consider alternative potential sources of supply to reliably serve customers and maintain feasibility. Operating pressure should be reduced to the lowest operationally feasible level in order to minimize methane emissions before non-emergency venting of high-pressure distribution (above 60 psig), transmission and underground storage infrastructure consistent with safe operations, and whenever practicable, work should be bundled to prevent multiple venting of the same piping.

5.3.7. If a new Transmission pipeline assembly is enclosed with wet canvases, the assembly may be directly purged into service using one canvas end as a vent provided that:

- When purging through a wet canvas, the canvas opening should be approximately $\frac{1}{3}$ of the cross-section of the pipe. The opening is at the bottom when purging into service. See [GS 223.016](#), *Temporary End Closures*.

5.4. Planning a Purge

5.4.1. Use **Table A1** in **Appendix A** to obtain the standard purging parameters for specific pipe diameters:

- These parameters include the standard injection fittings, injection pressures, vent sizes and flow rates.
- If orifices are to be utilized, use the required minimum flow rates from **Table A1**. Select the appropriate orifice size and inlet pressure based on required flow rates.
- Place the orifice immediately upstream of the injection fitting to eliminate any unplanned pressure drop.
- Orifices are normally placed in screwed orifice unions, but a tapped abandonment fitting can also be used. Injection and bypass fittings selected shall not have an internal diameter smaller than the hose or orifice to be used. See **Figure 6** for typical orifice set-up.

5.4.2. When using an orifice, the pressure gauge to measure minimum pressure should be installed just upstream of the orifice. The tapped diameter when

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using an abandonment fitting needs to be equal to or greater than the orifice size.

- 5.4.3. Use **Table A2** in **Appendix A** to obtain an approximate arrival time at specific lengths when using a standard set up. When indirectly purging, this time indicates the arrival of the slug.
- 5.4.4. When purging out of service using an air compressor, make certain that the selected compressor is rated with at least 15% more flow rate capacity than the minimum flow rate listed in **Table A1**.
- 5.4.5. When possible, purge from air/nitrogen to gas downhill, and purge from gas to air/nitrogen uphill.
- 5.4.6. A piping system containing loops or branches requires a detailed evaluation to ensure each pipe section is properly isolated and purged which typically requires isolating and purging in stages.

5.5. **Written Plan**

- 5.5.1. An approved written plan shall be available for all purging procedures.
- 5.5.2. Service lines and small diameter pipelines can be purged using the general procedures of this gas standard as the written plan. More complex purging operations require a specific detailed written plan.
- 5.5.3. The written plan shall include, but is not limited to, the required purging method, location of isolation points, injection set up, injection pressures and flow rates, venting location and stack size, operational sequences, an equipment list (model of gas scope, air compressor, etc.) and provisions for a communication system.

5.6. **Non-Typical Purging Operations**

- 5.6.1. When purging a service that has an Excess Flow Valve installed; see [GS 187.0146](#), *Excess Flow Valve (EFV) - Installation and Operation*.
- 5.6.2. Certain small diameter and lengths of mains and services do not require purging prior to abandonment, see [GS 184.0080](#), *Abandonment of Gas Services and Gas Light Tap Assemblies*, and [GS 184.0085](#), *Abandonment or Inactivation of Gas Distribution Pipelines*.
- 5.6.3. Air Movers may be used for purging large diameter ($\geq 8''$) pipelines out of service; see [GS 187.0103](#), *Purging Pipelines Using Air Movers For Cold Tie-In Operations*.

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- 5.6.4. If a standard indirect purge is not practical or possible, in cases such as long pipeline lengths yielding unreasonable purging times or if the use of larger injection fittings and/or vents is desired, contact **Gas Engineering - Pipeline Engineering** for analysis.
- 5.6.5. All non-standard purges require a written plan approved by **Gas Engineering - Pipeline Engineering**.

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6. PURGING OUT OF SERVICE USING THE DIRECT PURGE METHOD (GAS TO AIR)

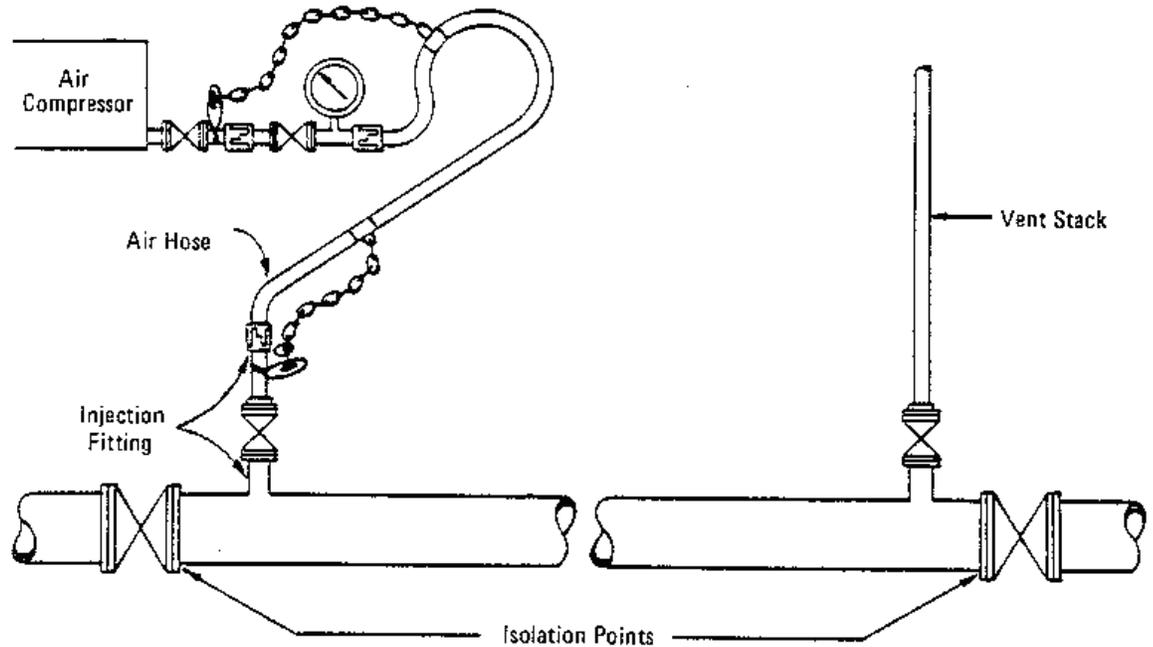


Figure 1. - Arrangement for Directly Purging Gas from Pipelines.

- 6.1. The Purging Operation Supervisor reviews the approved Written Plan and takes necessary actions to ensure all Company policies are adhered to. See **Section 5.5**.
- 6.2. Remove all ignition sources in accordance with **Section 5.2**.
- 6.3. Isolate section of line to be purged. See **Section 4.1**.
- 6.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, 6 to 8 feet above ground level. See **Figure 1**.
- 6.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. Connect air hose and valve to pressure gauge. See **Figure 1**.
- 6.6. Connect gauge and valve end of air hose to air compressor and attach other end of hose to injection fitting. See **Figure 1**.
- 6.7. Open valve on vent stack and blow down line.

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- 6.8. With the air compressor valve open, gradually open the valve on injection fitting and inject air. Inject at or above the minimum injection pressure. Injection of air shall be continued without interruption until the pipeline is purged of all gas. Control pressure with valve attached to compressor end of air hose. See **Figure 1**.
- 6.9. Stop injection of air when pipeline is purged of all gas. Use an approved combustible gas indicator to verify pipeline is 100% air. See [GS 107.0287](#), *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or [GS 223.0160](#), *Use of Portable Ranarex Gravimeters/Check Purges*.

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7. PURGING INTO SERVICE USING THE DIRECT PURGE METHOD (AIR/NITROGEN TO GAS)

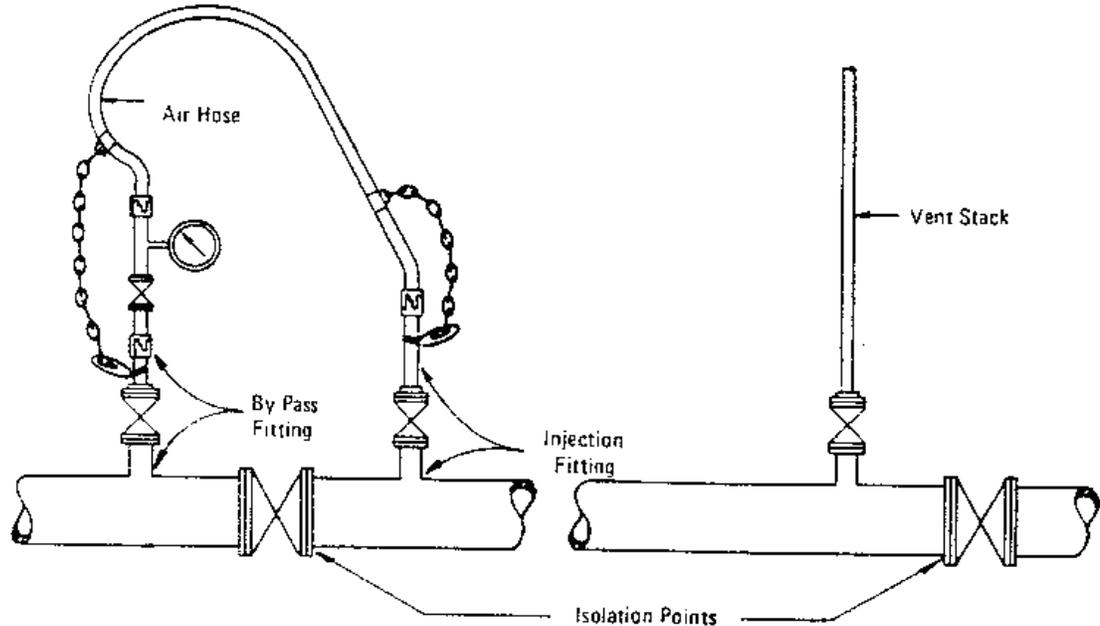


Figure 2 - Arrangement for Directly Purging Pipelines into Service.

- 7.1. The Purging Operation Supervisor reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.
- 7.2. Remove all ignition sources in accordance with **Section 5.2**.
- 7.3. Isolate section of line to be purged. See **Section 4.1**.
- 7.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, 6 to 8 feet above ground level. See **Figure 2**.
- 7.5. Install injection fitting as close as practical to, but not more than 5 feet away from the injection end of pipeline. See **Figure 2**. If available, gas may be injected by opening a line valve instead of using a bypass, however, contact **Gas Engineering - Pipeline Engineering** to obtain the downstream pressure needed to control the purge.
- 7.6. If needed, install bypass fitting on live pipeline for gas source. See **Figure 2**.
- 7.7. Connect gauge and valve to bypass fitting. Connect an air hose or pressure hose from pressure gauge end to injection fitting. See **Figure 2**.

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- 7.8. Open valve on vent stack.
- 7.9. Gradually open valve on injection fitting and inject gas. Inject at or above the minimum injection pressure. Injection of gas shall be continued without interruption until the pipeline is purged of all air. Control pressure with valve attached to bypass fitting. See **Figure 2**.
- 7.10. Stop injection of gas when pipeline is purged of air. Use an approved combustible gas indicator to verify pipeline is 100% gas. See [GS 107.0287](#), *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or [GS 223.0160](#), *Use of Portable Ranarex Gravimeters/Check Purges*.

A cursory odor sniff test shall be performed immediately after the purging process and verifying 100% gas is obtained.

- 7.11. For purging directly into service with high volume tapping tee and gas services less than 2” see **Section 12**.

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8. PURGING OUT OF SERVICE USING THE INDIRECT PURGE METHOD (GAS TO AIR)

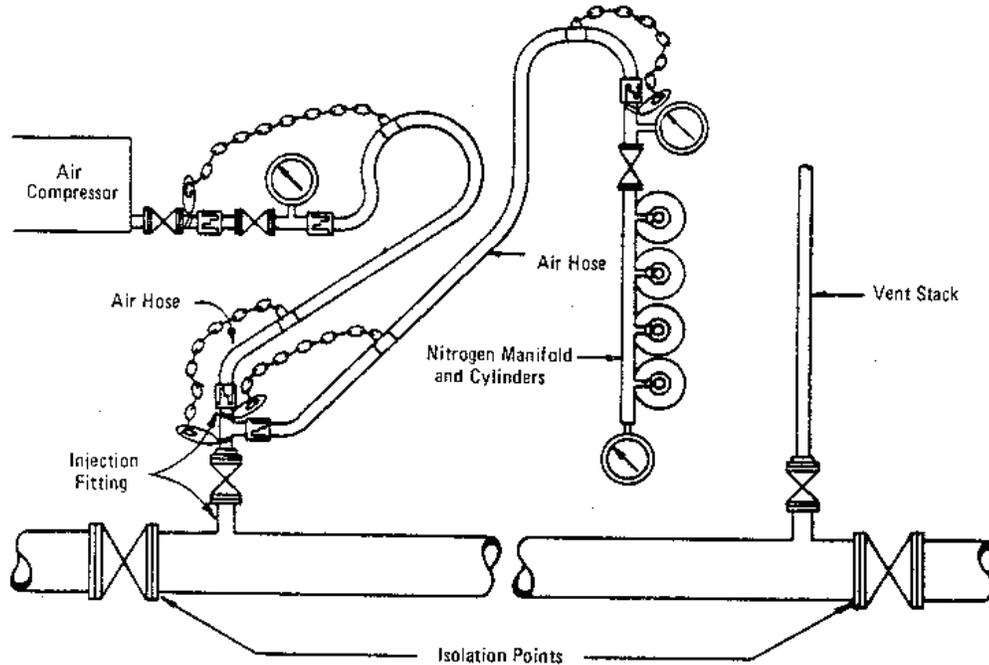


Figure 3. Arrangement for Purging Out of Service using Indirect Method

- 8.1. The Purging Operation Supervisor reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.
- 8.2. Remove all ignition sources in accordance with **Section 5.2**.
- 8.3. Isolate section of line to be purged. See **Section 4.1**.
- 8.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, 6 to 8 feet above ground level. See **Figure 3**.
- 8.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. See **Figure 3**.
- 8.6. Connect gauge and valve to air compressor and attach hose from the other end of the injection fitting. See **Figure 3**.
- 8.7. If nitrogen cylinders are to be used, connect the nitrogen cylinders to the manifold. Close valve on manifold and open valves on nitrogen cylinders. See **Figure 3**.

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- 8.8. Connect manifold hose or high-pressure hose to injection fitting. See **Figure 3**.
- 8.9. Open valve on vent stack and allow pipeline to blow-down.
- 8.10. Once the pipe segment has been blown down, gradually open valve on injection fitting.

Note: Verify this valve is open to prevent damage to the gauge on the manifold.

- 8.11. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure controlling pressure with the manifold valve. See **Figure 3**.
- 8.12. Begin injecting air as soon as the minimum gauge pressure of nitrogen, cannot be maintained. Close valve on nitrogen manifold immediately after air injection has started. Air must be injected at or above the minimum gauge pressure. Control pressure with valve attached to compressor end of air hose. See **Figure 3**.
- 8.13. Stop injection of air when pipeline is purged of gas. Use an approved combustible gas indicator to verify pipeline is 100% air. See [GS 107.0287](#), *GMI Gasurveyor – Combustible Gas Indicator (CGI)* and or [GS 223.0160](#), *Use of Portable Ranarex Gravimeters/Check Purges*.

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9. PURGING INTO SERVICE USING THE INDIRECT PURGE METHOD (AIR TO GAS)

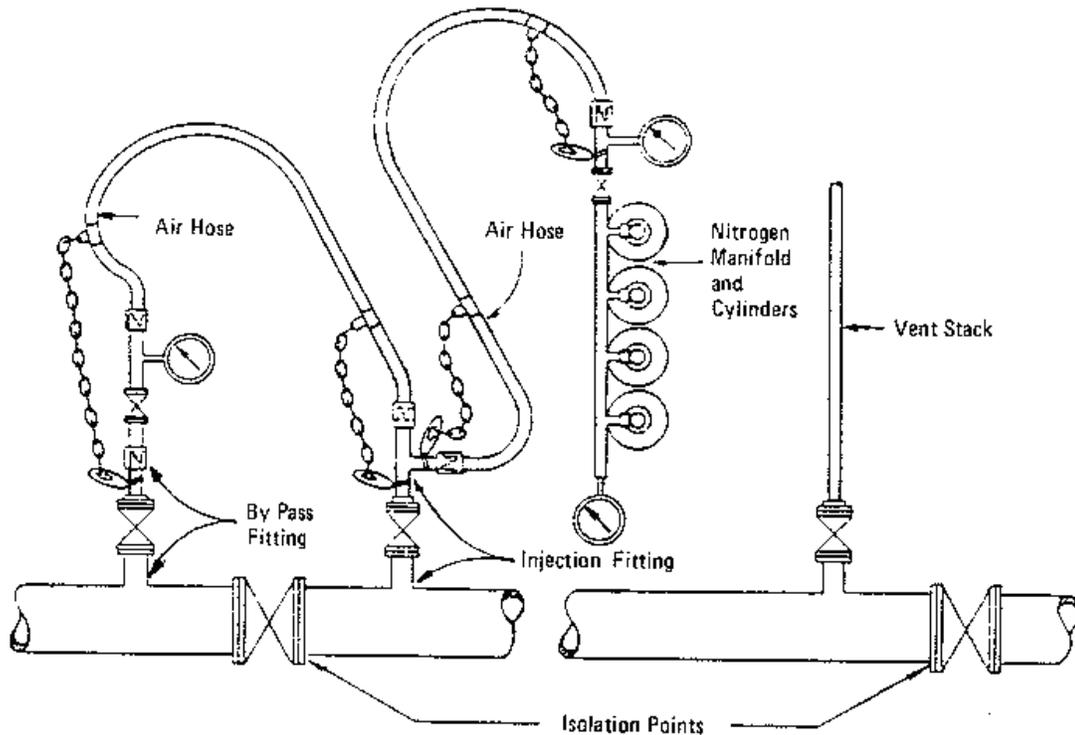


Figure 4. Arrangement for Purges into Service using Indirect Method

- 9.1. The Purging Operation Supervisor reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.
- 9.2. Remove all ignition sources in accordance with **Section 5.2**.
- 9.3. Isolate section of line to be purged. See **Section 4.1**.
- 9.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, 6 to 8 feet above ground level. See **Figure 4**.
- 9.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. See **Figure 4**. If available, gas may be injected by opening a line valve instead of using a bypass, however, contact **Gas Engineering - Pipeline Engineering** to obtain the downstream pressure needed to control the purge.
- 9.6. If needed, install bypass fitting on pipeline as a gas source. See **Figure 4**.

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- 9.7. Connect gauge and valve to bypass fitting. Connect an air hose from pressure gauge end to injection fitting. See **Figure 4**.
- 9.8. Connect nitrogen cylinders to the manifold. Close valve on manifold and open valves on nitrogen cylinders.
- 9.9. Connect manifold hose or high-pressure hose to injection fitting. See **Figure 4**.
- 9.10. Open valve on vent stack.
- 9.11. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure controlling pressure with the manifold valve. See **Figure 4**.
- 9.12. Begin injecting gas as soon as the minimum gauge pressure of nitrogen, cannot be maintained. Close valve on nitrogen manifold immediately after gas injection has started. Gas must be injected at or above the minimum gauge pressure. Control pressure with valve attached to bypass fitting. See **Figure 4**.
- 9.13. Stop injection of gas when pipeline is purged of air. Use an approved combustible gas indicator to verify pipeline is 100% gas. See [GS 107.0287](#), *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or [GS 223.0160](#), *Use of Portable Ranarex Gravimeters/Check Purges*.

A *cursorry odor sniff test* shall be performed immediately after the purging process and verifying 100% gas is obtained.

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10. PURGING OUT OF SERVICE USING THE TOTAL DISPLACEMENT METHOD (GAS TO NITROGEN)

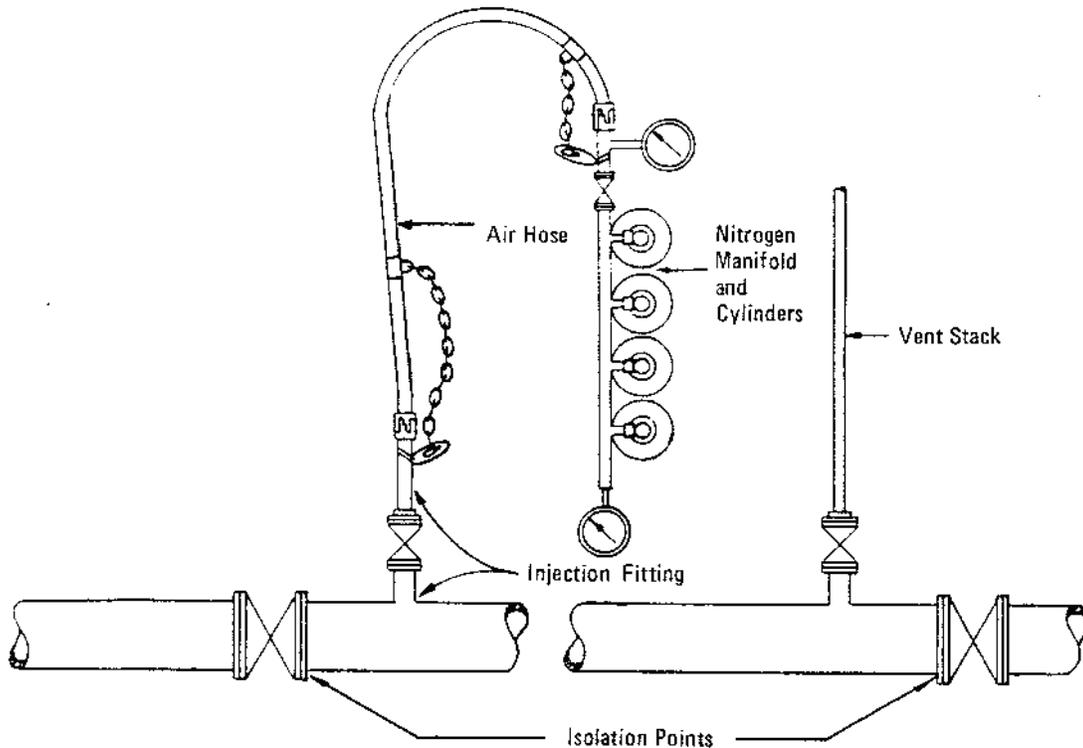


Figure 5. Arrangement for Purging Out of Service using Total Displacement Method

- 10.1. The Purging Operation Supervisor reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.
- 10.2. Remove all ignition sources in accordance with **Section 5.2**.
- 10.3. Isolate section of line to be purged. See **Section 4.1**.
- 10.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, 6 to 8 feet above ground level.
- 10.5. Install injection fitting as close as practical from the injection end of pipeline.
- 10.6. If nitrogen cylinders are to be used, connect the nitrogen cylinders to the manifold. Close valve on manifold and open valves on nitrogen cylinders. See **Figure 5**.

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- 10.7. Connect manifold hose to injection fitting. See **Figure 5**.
 - 10.8. Open valve on vent stack and blow-down the pipeline.
 - 10.9. Once the pipe segment is blown-down, open valve on injection fitting. Be sure this valve is open to prevent damage to the gauge on the manifold. See **Figure 5**.
 - 10.10. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure controlling pressure with the manifold valve. See **Figure 5**.
 - 10.11. Stop injection of nitrogen when pipeline is purged of gas. Use an approved combustible gas indicator to verify pipeline is purged of all gas. See [GS 107.0287](#), *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or [GS 223.0160](#), *Use of Portable Ranarex Gravimeters/Check Purges*.
 - 10.12. Sections with pipe left with 100% nitrogen must be stenciled “Nitrogen”. Also adjoining valves must be stenciled “Nitrogen”.
11. TYPICAL ORIFICE SET UP (DIRECT PURGE)

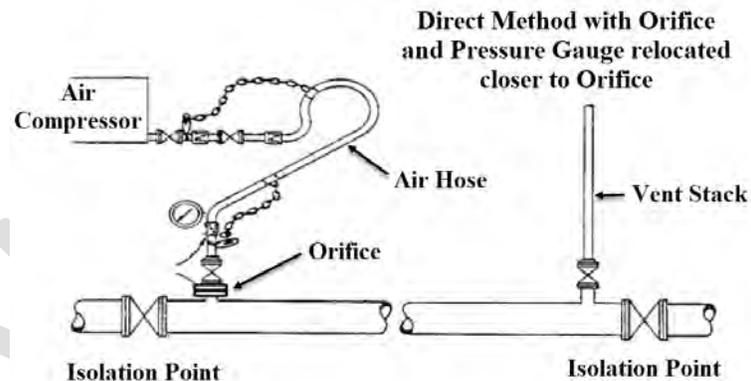


FIGURE 6

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12. ADDITIONAL REQUIREMENTS FOR PURGING POLYETHYLENE (PE) PIPE

CAUTION: Squeezers are never used as a control valve during purging operations.

12.1. Use one of the following methods when purging PE pipelines:

- A service riser without an EFV shall be used to purge a PE main. Install a temporary service-to-main connection (SMC) within 1 ft of the end of the main. A minimum 18” long steel nipple shall be installed in the service valve to help protect employees in the event of ignition.
- An anodeless riser shall be grounded with metallic grounding cable such as, but not limited to, a bond wire or jumper cable. Care shall be taken to avoid static electrical discharge before, during and after the purge by grounding all machinery and equipment where static electricity might accumulate.
- Purge through a purge assembly. Purge assemblies may be fabricated in the field, see **Figure 7** below.
- A purge assembly shall end with steel pipe, which is grounded, and the unit shall contain some method of positive control such as a service valve or ball valve.
 - A minimum 18” long vertical steel nipple should be installed in the service valve to help protect employee in the event of ignition
 - Fuse purge assembly to main
 - Ground purge stack and secure purge assembly from movement
 - Select the applicable purge operation, (e.g., direct purge from air to gas)

12.2. Use an approved combustible gas indicator to determine if pipeline is completely purged. See [GS 107.0287](#), *GMI Gasurveyor – Combustible Gas Indicator (CGI)* and or [GS 223.0160](#), *Use of Portable Ranarex Gravimeters/Check Purges*.

Abandon purge assembly if required. If a service-saddle or tapping tee was used, install appropriate protective sleeve over stub.

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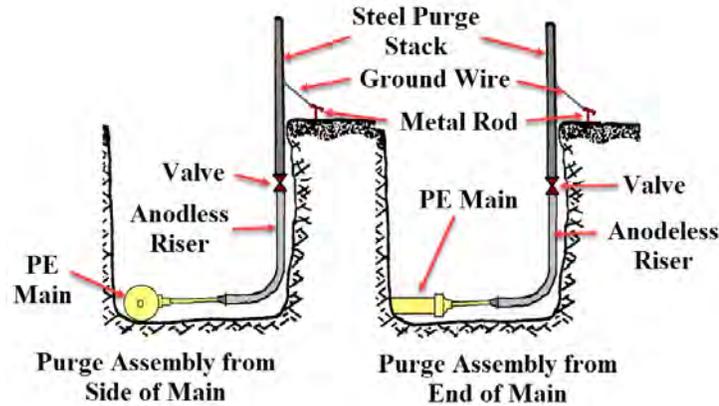


FIGURE 7

13. SPECIAL INSTRUCTION FOR PURGING DIRECTLY INTO SERVICE USING A HIGH-VOLUME TAPPING TEE AND FOR GAS SERVICES LESS THAN 2" DIAMETER
 - 13.1. **Direct purging into service a new 2-inch diameter medium pressure PE Main using a high-volume tapping tee as a pressure control fitting connected from 6" or 8" header main**
 - 13.1.1. Use the high-volume tapping tee as a pressure control fitting. It is not necessary to use a 50 ft. bypass hose to directly purge the new main into service. The high-volume tapping tee will become the purge source.
 - 13.1.2. Install the high-volume tapping tee in accordance with [GS 184.0115](#), *Tapping/ Stopping PE Fittings*.
 - 13.1.3. Tie new main onto the high volume tapping tee and leak test per [GS 184.0150](#), *Leak Testing of Distribution Piping with MAOP <= 60 PSIG*.
 - 13.1.4. Blow down the medium used for leak testing.
 - 13.1.5. Ensure vent-stack is in place, grounded and control valve is open. See [GS 166.0025](#), *Prevention of Accidental Ignition of Natural Gas* for proper grounding and to verify all potential sources of ignition are eliminated.

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NOTE: Using a properly sized 50 ft. bypass hose is also allowed, but squeezing the 2” PE pipe next to the outlet of the high-volume tapping tee will be needed. Squeezing needs to be performed before directly purging the new main into service in order isolate “back fed” gas from the bypass connection. The squeezer can be released after the high-volume tapping tee has been installed, tapped, capped, and sealed.

- 13.1.6. Ensure the ratchet wrench is grounded then place tapping tool and start tapping per [GS 184.0115](#) *Tapping/Stopping PE Fittings*. Thread the cutter down until it seats in the main to effectively shut off the gas flow.
- 13.1.6.1. The high-volume tapping tee will now act as a pressure control fitting to directly purge the new main into service.
- 13.1.7. The crew member located at the vent stack is to maintain the control valve fully open and ready for the purge to commence.
- 13.1.8. Begin the purge discharge (at the riser outlet) by backing off the high-volume tapping tee and introducing natural gas to the new 2” main.
- 13.1.9. Confirm the purge is complete by verifying 100% gas at the vent location using a Company approved combustible gas indicator at the vent location. See [GS 107.0287](#), *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or [GS 223.0160](#), *Use of Portable Ranarex Gravimeters/Check Purges*.
- 13.1.10. After a complete purge has been confirmed, close the control valve. The new main is now pressurized and purged into service.
- 13.2. **Direct purging of steel gas services less than 2” diameter can be accomplished using a service tee or pin-off tee as the purge source.**

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14. PURGING SERVICES LINES THROUGH RISERS

CAUTION: The greatest potential hazard of static electricity is when gas is being vented to the atmosphere at high velocity. Care shall be taken to avoid static electrical discharge before, during and after purge by grounding all machinery and equipment where static electricity might accumulate. See [GS 166.0025](#), *Prevention of Accidental Ignition of Natural Gas* to address this hazard.

- 14.1. See **Section 12** for additional requirements when purging a Polyethylene (PE) pipeline.
- 14.2. Keep public clear of the area. If pedestrian encroachment is anticipated, post warning signs, barricades, etc., to deter persons from entering area.
- 14.3. Verify service valves are in the closed position.
- 14.4. Remove the threaded plug from the closed service valve of the service riser and install a purge stack or purge bag.
- 14.5. Insert grounding rod into earth. Whenever possible, moisten the soil around the grounding rod to increase the grounding effect.
- 14.6. Connect one end of a ground wire to the purge stack and the other end to a grounding rod.
- 14.7. Direct the blowing of air, gas and possible debris into the open atmosphere, away from workers, the public and private property. Exhaust gas away from buildings, equipment, enclosures and any possible sources of ignition, including overhead power lines.
- 14.8. If it is anticipated that an extensive amount of purging is to take place, dispatch should be notified of possible area odor complaints.
- 14.9. When an Excess Flow Valve (EFV) has been installed, open the service valve slowly and sufficiently to near the maximum flowrate that can be achieved without tripping the EFV. If the EFV trips during purging, wait for the EFV to re-set, and repeat the purge process again at a slightly slower flowrate. Refer to [GS 187.0146](#), *Excess Flow Valve (EFV) - Installation and Operation*, for reset time based on pressure, size and length of service.
- 14.10. For Service Lines without an EFV, open the service valve quickly to purge.
- 14.11. Use an approved combustible gas indicator to determine if pipeline is completely purged. See [GS 107.0287](#), *GMI Gasurveyor – Combustible Gas Indicator (CGI)* or [GS 223.0160](#), *Use of Portable Ranarex Gravimeters/Check Purges*.

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A *cursory odor sniff test* shall be performed immediately after the purging process and verifying 100% gas is obtained.

Note: If gas odor is not detectable by smell, notify supervision. If situation cannot be resolved, supervision is to contact the Region Engineer.

- 14.12. Close the service valve and remove the purge stack and grounding wire.
- 14.13 Replace the threaded plug in the closed service valve and soap test for leaks, per [GS 184.0150](#), *Leak Testing of Distribution Piping with MAOP <= 60 PSIG*.
- 15. OPERATOR QUALIFICATION COVERED TASKS
(See [GS 167.0100](#), *Operator Qualification Program, Appendix A, Covered Task List*)
 - **Task 07.01** - 49 CFR 192.629 – Purging pipelines
 - **Task 16.02** - 49 CFR 192.745 – Inspecting, operating, and maintaining transmission pipeline valves
 - **Task 16.03** - 49 CFR 192.747 – Inspecting, operating, and maintaining distribution system valves
- 16. EXCEPTION PROCEDURE
See [STANDARD 182.0004](#), *Exception Procedure for Company Operations Standards*)
 - 16.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.
 - 16.2. An exception from a standard shall not be allowed unless [GS 182.0004](#), *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.
- 17. RECORDS
Not Applicable.
- 18. APPENDICES
 - 18.1. Appendix A

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APPENDIX A

**Table A1
Minimum Equipment Requirements for Purging Pipeline**

Nominal Pipe Size (inches)	Hose Diameter** (inches)	Minimum Nominal Stack Stack Size*** (inches)	Minimum Gauge Pressure *		Minimum Injection Flow Rate (SCFM)
			Gas (psig)	Nitrogen/Air (psig)	
4 and less	3/4	3/4	3	3	11
6	3/4	1 -1/2	6	8	29
8	3/4	1 -1/2	15	18	56
10	3/4	2	28	35	96
12	3/4	3	47	59	149
16	1 1/4	3	19	26	273
18	1 1/4	4	28	40	367
20	1 1/4	4	41	55	489
22	1 1/4	4	55	75	615
26	2	6	21	30	930
30	2	6	32	45	1331
34	2	6	45	65	1821
36	2	6	54	77	2117

* Pressures listed are based upon placing a pressure gauge 50 feet upstream of the injection point. Shorter distances yield greater injection rates and shorten purge durations. Contact **Gas Engineering - Pipeline Engineering** if hose distances are greater than 50 feet.

** If it's necessary to use a Hose Diameter larger than specified, contact **Gas Engineering - Pipeline Engineering** for the lower required minimum gauge pressure.

*** For vents in excess of 10 ft long, go to next larger pipe size. Multiple vent stacks are allowed if a single vent stack does not meet the minimum requirements. The total internal flow area of the multiple vents needs to be greater to the internal flow area of the required vent size. Contact **Gas Engineering - Pipeline Engineering** for guidance on correct combinations of vent stacks.

Note: The diameter of manifolds should at least be equal to the hose diameter required for purging.

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Table A1*
Measuring Rates Through Orifices
Use these figures for measuring the injection rates while purging.
(Note: All Hose and Orifice Sizes are Internal Diameters)

Inject Rate (cfm)	Pressure Upstream of Orifice (psig) (Note: All Hose and Orifice Sizes are Internal Diameters)									
	Orifice Size (inches)									
	3/8		1/2		5/8		3/4		7/8	
	Gas	N ₂ Air	Gas	N ₂ Air	Gas	N ₂ Air	Gas	N ₂ Air	Gas	N ₂ Air
10										
20										
40	7	12								
60	19	26	5	8						
80	30	39	11	16	2	5				
100	41	53	18	24	6	10				
120	52	67	25	31	10	14				
140	63	80	31	39	14	19				
160	75	94	38	47	19	24				
180	86	107	44	54	23	29				
200	97	121	51	62	27	34				
220	106	136	53	70	29	39	17	22	9	13
240	117	150	59	78	33	44	20	26	11	15
260	128	163	66	85	37	49	22	29	13	18
280	139	177	72	93	41	54	25	33	15	20
300	150	191	78	101	45	59	28	36	17	23
320	161	205	84	109	49	64	31	39	19	25
340	172	218	90	116	53	69	34	43	21	28
360	183	232	97	124	57	74	37	46	24	30
380	194	246	103	132	61	78	40	50	26	33
400	205	259	109	139	65	83	43	53	28	35
420	216	273	115	147	69	88	45	56	30	38
440	227	287	121	155	73	93	48	60	32	40
460	238	301	128	163	77	98	51	63	34	43
480	249	314	134	170	81	103	54	67	36	45
500	260	328	140	178	85	108	57	70	39	48
550	286	362	156	197	95	120	61	79	41	53
600	314	397	171	217	105	133	68	87	46	59
650	341	431	187	236	115	145	75	96	51	65
700	369	465	202	255	125	157	82	104	56	71
750	396	500	218	275	135	170	89	113	62	77
800	423	534	233	294	145	182	95	121	67	83
850	451	568	249	313	155	194	102	130	72	90
900	478		264	332	165	206	109	138	77	96
950	506		280	352	175	219	116	147	82	102
1000	533		295	371	185	231	123	155	87	108
1050	560		311	390	195	243	130	164	92	114
1100	588		326	410	205	256	137	172	97	120
1150			342	429	215	268	144	181	102	126
1200			357	448	225	280	151	189	107	133
1250			373	468	235	293	158	198	113	139
1300			388	487	245	305	164	206	118	145
1350			404	506	255	317	171	215	123	151
1400			419	525	265	329	178	223	128	157
1450			435	545	275	349	185	232	133	163
1500			450	564	285	354	192	240	138	170
1550			466	583	295	366	199	249	143	176
1600			481		305	379	206	257	148	182
1650			497		315	391	213	266	153	188
1700			512		325	403	220	274	158	194
1750			528		335	416	227	283	164	200
1800			543		345	428	233	291	169	206
1850			559		355	440	240	300	174	213
1900			574		365	452	247	308	179	219
1950			590		375	465	254	317	184	225
2000					385	477	261	325	189	231
2050					395	489	268	334	194	237
2100					405	502	275	342	199	243

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Table A1 (continued)*
Measuring Rates Through Orifices
 Use these figures for measuring the injection rates while purging.
 (Note: All Hose and Orifice Sizes are Internal Diameters)

Inject Rate (cfm)	Pressure Upstream of Orifice (psig) (Note: All Hose and Orifice Sizes are Internal Diameters)							
	Orifice Size (inches)							
	1-1/8		1-3/8		1-1/2		1-3/4	
	Gas	N ₂ Air	Gas	N ₂ Air	Gas	N ₂ Air	Gas	N ₂ Air
10								
20								
40								
60								
80								
100								
120								
140								
160								
180								
200								
220		2						
240		3						
260	2	5						
280	3	6						
300	4	8						
320	5	9						
340	7	11						
360	8	12						
380	9	14						
400	11	15						
420	12	17						
440	13	18						
460	14	20						
480	16	21						
500	17	23						
550	20	26	9	13				
600	23	30	11	15				
650	26	34	13	18				
700	29	38	15	20				
750	32	41	17	23				
800	35	45	19	25				
850	39	49	22	28				
900	42	53	24	30				
950	45	56	26	33				
1000	48	60	28	35	18	26	9	15
1050	51	64	30	38	20	28	10	17
1100	54	68	32	40	21	30	11	18
1150	57	71	34	43	23	32	13	20
1200	61	75	37	45	25	34	14	21
1250	64	79	39	48	26	36	15	23
1300	67	83	41	50	28	38	16	24
1350	70	86	43	53	30	40	17	26
1400	73	90	45	55	31	42	19	27
1450	76	94	47	58	33	44	20	29
1500	80	98	50	60	35	47	21	30
1550	83	101	52	63	36	49	22	32
1600	86	105	54	65	38	51	23	33
1650	89	109	56	68	39	53	25	35
1700	92	113	58	70	41	55	26	36
1750	95	116	60	73	43	57	27	38
1800	98	120	62	75	44	59	28	39
1850	102	124	65	78	46	61	29	41
1900	105	128	67	80	48	63	31	42
1950	108	131	69	83	49	65	32	44
2000	111	135	71	85	51	67	33	45
2050	114	139	73	88	53	69	34	47
2100	117	143	75	90	54	71	35	48

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Table A2**

Pipe Size (in.)	Estimated Duration of Purge (min)									
	Length of Pipe (feet)									
	1000	2000	3000	4000	5000	6000	8000	10000	20000	50000
4 and less	8	16	24	32	40	48	64	80	160	400
6	8	16	23	31	39	46	62	77	154	385
8	7	14	20	27	34	40	54	67	134	334
10	6	12	18	25	31	37	49	61	122	303
12	6	11	17	22	28	34	45	56	111	278
16	5	10	15	19	24	29	38	48	96	238
18	5	9	14	18	23	28	37	46	91	228
20	5	9	13	17	22	26	34	43	85	213
22	4	8	13	16	21	25	33	41	82	205
26	4	8	12	15	19	23	30	38	76	189
30	4	7	11	14	18	21	28	35	70	176
34	4	7	10	13	17	20	27	33	66	164
36	3	7	10	13	16	19	26	32	64	159

Values of time for length not shown may be interpolated. For assistance with interpolation, contact **Gas Engineering - Pipeline Engineering.

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Table A3
Number of Nitrogen Cylinders (250 Cubic Feet Each) Required To Form Slug in Pipeline
Indirect Method

Pipe Size (inches)	Pipe Length (ft)									
	500**	1000	2000	3000	4000	5000	7500	10,000	20,000	50,000
4	1	1	1	1	1	1	1	1	1	1
6	1	1	1	1	1	1	1	1	1	2
8	1	1	1	1	1	1	1	1	2	2
10	1	1	1	1	1	2	2	2	2	3
12	1	1	2	2	2	2	2	2	3	4
16	2	2	2	2	3	3	3	4	5	7
18	2	2	3	3	3	4	4	5	6	9
20	2	3	3	4	4	4	5	6	7	11
22	3	3	4	4	5	5	6	7	9	13
26	4	4	5	6	6	7	8	9	12	18
30	5	5	7	8	8	9	11	12	16	24
34	6	7	9	11	12	13	15	17	23	35
36	7	8	10	12	13	15	17	19	26	39

** Pipelines less than 500 ft may be displaced directly with air or gas. Please refer to **Table 1** “Purging Method” in this Gas Standard for additional guidance.

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Table A4
Number of Nitrogen Cylinders (250 Cubic Feet Each) Required To Fill Pipeline
Total Displacement Method

Pipe Size (inches)	Pipe Length (ft)											
	500	1000	2000	3000	4000	5000	6000	8000	10,000	20,000	50,000	
2	1	1	1	1	1	1	1	1	2	3	5	
3	1	1	1	1	1	2	2	2	3	5	11	
4	1	1	2	2	2	3	3	4	5	9	19	
6	1	2	3	4	5	6	8	10	19	*42		
8	1	2	4	5	7	9	10	13	17	*33	*74	
10	2	3	6	8	11	13	16	21	26	*52	*116	
12	2	4	8	11	15	19	22	29	*37	*73	*164	
16	3	6	12	17	23	28	*34	*45	*56	*112	*254	
18	4	8	15	22	29	*36	*43	*58	*72	*143	*325	
20	5	9	18	27	*36	*45	*54	*72	*89	*178	*405	
22	6	11	22	*33	*44	*55	*66	*87	*109	*217	*494	
26	8	16	31	*46	*62	*77	*92	*123	*154	*307	*696	
30	11	21	*42	*62	*83	*103	*124	*165	*206	*411	*934	
34	14	27	*54	*80	*107	*133	*160	*213	*266	*531	*1206	
36	15	30	*60	*90	*120	*150	*179	*239	*299	*597	*1356	

* Consider using a nitrogen truck for purges. See Table A5 for volume in SCF.

Table A5
Volume (SCF) of Nitrogen Required To Form Slug in Pipeline
Indirect Method

Pipe Size (inches)	*Pipe Length in Feet						
	2000	3500	5000	7500	10,000	20,000	50,000
12	263	321	368	433	486	653	985
16	430	527	605	712	802	1080	1632
18	553	677	777	915	1030	1387	2097
20	689	844	968	1139	1283	1728	2611
22	831	1017	1168	1375	1548	2085	3151
26	1162	1424	1633	1923	2165	2916	4406
30	1546	1895	2173	2561	2880	3880	5863
34	2204	2722	3137	3711	4189	5677	8630
36	2480	3067	3531	4179	4716	6391	9714

*Consider using bottles for smaller diameters and shorter lengths.

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Table A6
Volume (SCF) of Nitrogen Required To Fill Pipeline
Total Displacement Method

Pipe Size (inches)	Pipe Length in Feet										
	500	1000	2000	3000	4000	5000	6000	8000	10,000	20,000	50,000
6	*116	*231	*461	*691	*921	*1,151	*1,381	*1,840	*2,300	4,600	11,498
8	*202	*403	*805	*1,206	*1,608	*2,010	*2,412	*3,215	4,019	8,037	20,091
10	*320	*639	*1,277	*1,915	*2,552	*3,190	*3,828	5,104	6,379	12,758	31,893
12	*451	*902	*1,802	*2,703	*3,604	4,504	5,405	7,206	9,007	18,014	45,032
16	*699	*1,397	*2,792	4,188	5,584	6,979	8,375	11,166	13,957	27,914	69,782
18	*894	*1,786	*3,571	5,357	7,142	8,927	10,712	14,283	17,853	35,705	89,261
20	*1,112	*2,224	4,447	6,670	8,893	11,116	13,339	17,784	22,230	44,459	111,147
22	*1,357	*2,713	5,425	8,136	10,848	13,560	16,272	21,695	27,119	54,237	135,591
26	*1,915	*3,828	7,655	11,482	15,309	19,136	22,964	30,618	38,272	76,543	191,355
30	*2,568	5,134	10,268	15,401	20,534	25,668	30,801	41,068	51,334	102,668	256,668
34	*3,316	6,632	13,262	19,893	26,523	33,154	39,784	53,045	66,307	132,612	331,529
36	*3,729	7,457	14,912	22,368	29,823	37,279	44,734	59,645	74,557	149,112	372,779

* Consider using bottles for purges.



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Purging Pipelines and Components	SCG:	182.0160
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<p style="text-align: center; margin: 0;">NOTE: Do not alter or add any content from this page down; the following content is automatically generated.</p> <p style="margin: 0;">Brief: Fully reviewed. Re-structured and re-formatted the standard for clarity, added/revised Sections 12, 13, and 14. Provided additional clarity on CGI requirements for purging operations, and various editorial changes.</p>
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Company Operations Standard Gas Standard Distribution Operations

Construction Planning for Mains and Supply Lines

SCG:

184.0015

PURPOSE To provide guidelines and requirements for construction planning of Distribution mains, supply lines, and related service installations.

1. POLICY AND SCOPE

- 1.1. The Company provides guidance and instruction to properly plan the installation of Distribution natural gas facilities.

2. RESPONSIBILITIES AND QUALIFICATIONS

- 2.1. Gas Operations is responsible for the content and administration of this Gas Standard.
- 2.2. The Regions are responsible for implementation of, and adherence to, this Standard.
- 2.3. Only personnel qualified through Field Operations Training or Welding Training may perform these operations. See [STANDARD 167.0100](#), *Operator Qualification Program* and [STANDARD 184.0590](#) *Pressure Control Qualification Requirements*.
- 2.4. Field employees are responsible for adhering to Company procedures and shall wear appropriate personal safety equipment during any and all duties performed. See *Injury and Illness Prevention Program Binder* under [MANUAL IIPP.4](#), *Employee's Responsibilities*.

3. DEFINITIONS

- 3.1. Not applicable.

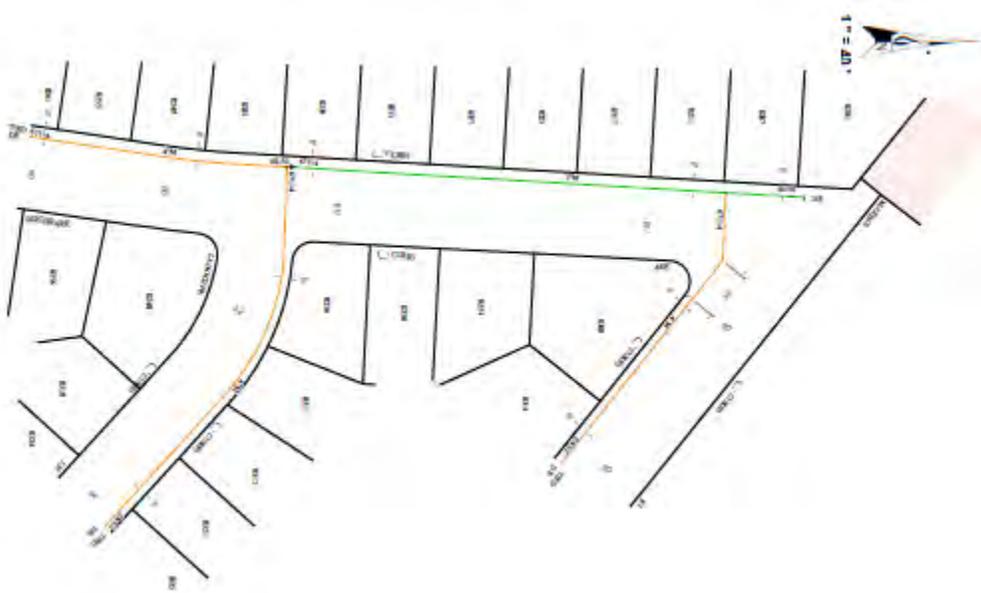
4. PROCEDURE

- 4.1. Items typically provided by the Planning and Engineering office include;
- 4.1.1. Job “package” envelope, tract map, plot plan, grading plan, etc.
- 4.1.2. Print of proposed work order sketch / base sketch or other map of the job location suitable for field preparation of the “planner’s sketch.” See [Standard 192.0005](#) *Preparation of Work Order / Base Sketch*. Figure 1 below demonstrates a sample base sketch drawing using GIS data.

Company Operations Standard Gas Standard Distribution Operations

Construction Planning for Mains and Supply Lines	SCG:	184.0015
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Figure 1



- 4.1.3. Strip map (reproduction of a Company atlas), denoting the limits of the proposed installation or replacement.
- 4.1.4. All substructure data available including proposed utilities if known
- 4.1.5. For replacement work, include archive copies of the original completion sketches (As-Built) for all existing facilities involved if available.
- 4.1.6. Public and private improvement plans (if applicable).
- 4.1.7. Special permit requirements or depth requirements.
- 4.1.8. Proposed pipe size, kind and design level. Specify branch connections to be installed in header mains to provide for known future laterals.
- 4.1.9. Service list or plan and service history information.
- 4.1.10. Valve requirements. See [STANDARD 180.0085](#), *Valve Usage and Selection Guide*.
- 4.1.11. Main ties that affect an isolation area and the isolation area number.
- 4.1.12. Ties and dead ends for pipe to be installed and abandoned.

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NOTE: The gas supply to the entire affected piping system must be reviewed to correctly identify the source(s) of gas related to the construction area. Ensure piping and gas supply is properly identified to assure a constant supply of gas to the area during and after construction.

- 4.2. Corrosion control requirements and the locations of Company and foreign impressed current anode systems and the facilities they protect.
 - 4.2.1. As much information as possible about paving and soil conditions.
- 4.3. Downstream filtration requirements see [STANDARD 184.0281](#), *Filtration Requirements for Regulator Stations*.
- 4.4. Field planning requirements include (site investigation and consideration):
 - 4.4.1. On site working conditions such as residential or industrial area, type and thickness of paving, if known, shoring requirements, traffic control needs, etc.
 - 4.4.2. Determine if excavating operations will take place within 500 feet of a school (K-12) or hospital requiring pre-construction notification to the facility(s) per Assembly Bill (AB) 1937.
 - 4.4.3. Locations of property lines and curbs.
 - 4.4.4. Foreign substructures.
 - 4.4.5. Locations of specified job terminals.
 - 4.4.6. Locations and depth requirements for main and related facilities
 - 4.4.7. Methods of installation.
 - 4.4.8. Special permit requirements.
 - 4.4.9. **Pressure control and gas handling requirements. See [Standard 184.06](#), *Gas-Handling and Pressure Control*.**
 - 4.4.10. For steel pipe installation, determine the need for odorant “seasoning” of the line; see [Standard 189.002](#) *Odor Conditioning of New Steel Lines*.
 - 4.4.11. Cathodic protection requirements.
 - 4.4.12. Related service work.
 - 4.4.13. Material requirements.

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Construction Planning for Mains and Supply Lines

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- 4.4.14. Installation and abandonment footage.
- 4.4.15. Planning for subdivisions.
- 4.4.16. Construction marking requirements.
- 4.4.17. Written gas handling procedures. See [Standard 184.06](#), *Gas-Handling and Pressure Control*.
- 4.5. Environmental
 - 4.5.1. Consider proximity to environmental resources when planning the facility locations.
 - 4.5.2. If the site is known to be in proximity to a sensitive resource, an environmental review must be conducted by a Field Environmental Representative (FER) or Environmental Services (EPro).
 - 4.5.2.1. Document compliance with environmental pre-screening in the current construction management system and on the main package cover sheet.
- 4.6. Preparation of sketches by the project planner:
 - 4.6.1. Prepare a rough sketch, also called a “Planner’s Sketch”, of the proposed field layout after field planning. Draw the sketch on a print of the work order / base sketch.
 - 4.6.1.1. A rough sketch may be drawn on a strip map, tract map, atlas sheet, or other suitable map of the job site and transferred to the work order sketch / base sketch prior to routing to the Planning and Engineering office.
 - 4.6.1.2. The Planner’s Sketch will be used to create the Construction Sketch and it must contain all required information for that process. See [STANDARD 192.0010](#) *Preparation of Construction Sketches*.
 - 4.6.2. Prepare the substructure sketch using information obtained from local municipalities and other utilities. (Utility member contact information can be obtained from underground service alert). Add any additional substructures found within the job limits during the on-site visit. See [STANDARD 192.0015](#) *Preparation of Substructure Sketch*.

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4.6.2.1. Especially note surface structures when planning the route of the new pipeline, i.e. sewer manholes, telephone vaults, etc. The actual underground structure may be substantially larger than what is observed on the surface.

NOTE: A copy of Agency composite substructure map or improvement plans showing substructures are not an acceptable alternate to the substructure sketch.

4.6.3. Route Planners Sketch for approvals per [STANDARD 184.0014](#) *New Business Project Package Routing* and/or [STANDARD 184.0016](#) *Main Construction Project Package Routing*.

4.7. Planning and Engineering tasks include:

4.7.1. Distribution pipelines considered transmission lines as defined by [STANDARD 223.0415](#) *Pipeline and Related Definitions (Interpretation of 49 CFR 192.3)*, are evaluated to determine if the pipeline will be constructed in a High Consequence Area (HCA) per [STANDARD 192.02](#), *Operations Technology Procedure*.

4.7.1.1. [FORM 4262](#), *Request for Pipeline Assistance*, shall be used to document that a review has been performed to determine any impacts to transmission pipelines within HCA's. See [Standard 182.0010](#), *Request For Pipeline Design Assistance*.

4.7.2. Submit approved Planners Sketch for preparation of Construction Sketch. See [STANDARD 192.0010](#), *Preparation of Construction Sketches*.

4.7.3. Prepare a Request for Proposal (RFP) for those jobs that are considered for bid. See [STANDARD 103.0010](#), *Special Specifications – Request for Proposal (RFP) Process*.

4.7.4. For high pressure jobs enter all pipe, fittings and design information into the Design Data Sheet (DDS) Manager program to verify that all materials qualify for the design level and to determine strength testing requirements. See [STANDARD 182.0170](#) *Strength Testing Pipelines and Facilities*, and [FORM 3222](#), *Design Data Sheet (DDS)*.

4.7.5. When required, process a *New Steel Pipeline Information Form* to the EAC Project Manager to procure an odorization plan for the pipeline. See 189.002, *Odor Conditioning of New Steel Lines*.

4.7.6. Obtain Right of Way and Railroad Crossing Agreements, when applicable. See [STANDARD 106.0021](#), *Land and Right of Way Amendments*.

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NOTE: The need for Right of Way or easements should be identified and the process started as soon as possible to prevent delays in the project.

4.7.7. Review permit requirements prior to releasing job package for special requirements that can be added to construction sketch.

5. OPERATOR QUALIFICATION COVERED TASKS
Not applicable.

6. RECORDS

6.1. The main job packages are to be retained per Company Records Retention Policy OPS-20-02, life of the asset plus five years (LOA+5).

7. APPENDICES

Not applicable.

INTERNAL



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<p>NOTE: Do not alter or add any content from this page down; the following content is automatically generated.</p> <p>Brief: Replaced Figure 1 with GWD based sample, changed references to suit new systems and programs (ex: CMS vs. CPD), various grammar and narrative changes not affecting the intent of the document.</p>

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Company Operations Standard Gas Standard Gas Operations

Planning Shutdowns for Transmission and Storage	SCG:	223.0145
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PURPOSE **The purpose of this Gas Standard is to describe the planning, coordination, and notifications necessary for planned and emergency shutdowns of Transmission and Storage Operations pipelines, compressor stations, and storage fields.**

1. **POLICY AND SCOPE**

1.1. Gas facility shutdowns which require a written shutdown plan:

- **Transmission Pipelines** — all work on transmission pipelines except work of very short duration (e.g., stroking valves as part of preventative maintenance inspection).
- **Compressor Stations** — all work that reduces the throughput capacity of station, except work on individual units which results in reduction of throughput for less than two hours
- **Underground Storage Fields** — all work affecting injection or withdrawal capability, except routine well testing (e.g. sand test, individual engine use for unloading wells).

NOTE: All **Transmission** and **Storage** shutdowns, even those not requiring written plan, must be coordinated through **Gas Control** and must receive **Gas Control** approval prior to commencement. (Certain emergency situations are excepted — see Section 4.4, below.)

2. **RESPONSIBILITIES & QUALIFICATIONS**

- 2.1. **Transmission and Storage Operations** develop written plans for coordination and execution of gas facility (pipeline, compressor station, storage field) shutdowns to ensure operational effectiveness, as well as public, employee, and facility safety.
- 2.2. **Transmission and Storage Operations** will coordinate all planned and probable shutdowns with **Gas Control** ahead of the proposed shutdown period.
- 2.3. **Project Managers, operating supervisors, and other Company personnel** responsible for projects that necessitate shutdowns shall notify **Energy Markets** and/or **Commercial/Industrial** when shutdowns affect the flow of gas to Utility Electrical Generation (UEG)/wholesale customers or that would affect producers.
- 2.4. **Gas Control** reviews forecasted shutdowns and related plans; coordinates changes in planning schedules; coordinates with suppliers, producers, and UEG/wholesale customers and advises **operating supervisors** regarding gas handling arrangements (valve operations, etc.).

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3. DEFINITIONS

- 3.1. EOC – Emergency Operations Center for Company
- 3.2. GEC – Gas Emergency Center for Region
- 3.3. Isolated Section – any section of pipeline facility that is physically shutdown in an emergency or planned shutdown
- 3.4. Shutdown – Any work that restricts the use or availability of transmission pipelines, compressor stations, or storage fields, including instrumentation repair and calibration at affected facilities and pipelines

4. PROCEDURE

4.1. Planned Shutdown

4.1.1. **Transmission and Storage Operations** shall notify **Gas Control** of any possible timing flexibility to enhance coordination with other planned shutdowns.

4.1.2. Notify the following affected parties (if affected):

- **Transmission Technical Services Manager**
- **Storage Technical Services Manager** and affected **Storage Operations Manager**
- The affected **Distribution Region Technical Services Manager**

4.1.3. Plan work so that the duration of the shutdown is held to a minimum.

4.1.4. Working with **Gas Control** and **Distribution Region Technical Services**, plan to minimize gas blown to atmosphere through the use of **Distribution** facilities to reduce gas pipeline inventory. Any project that requires gas blown to atmosphere will build time into the project schedule to reduce methane consistent with safe operations and consider alternative potential sources of supply to reliably serve customers and maintain feasibility. Operating pressure should be reduced to the lowest operationally feasible level in order to minimize methane emissions before non-emergency venting of high-pressure distribution (above 60 psig), transmission and underground storage infrastructure consistent with safe operations. and whenever practicable, work should be bundled to prevent multiple venting of the same piping.

4.1.5. Consult with **Gas Control** and **Distribution Region Technical Services** as necessary to plan and coordinate activities with other **Transmission** and

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Planning Shutdowns for Transmission and Storage	SCG:	223.0145
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Storage Operations organizations, affected **Distribution Regions**, suppliers, producers, and customers.

- 4.1.6. Plan and execute shutdowns to assure that pressures in adjoining sections of the pipeline will not drop below minimum operating requirements. As necessary during the planning and execution phases, consult with affected **Distribution Region Technical Services** and **Gas Control**.

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- 4.1.7. When tentative arrangements can be reasonably determined, contact:
- **Gas Control**
 - The affected **Distribution Region Technical Services** to plan remedial action on the distribution system and for notifications, such as transportation customers, etc.
 - Producers, where affected.
- 4.1.8. The following notifications will be made in advance of scheduled shutdowns:
- **Gas Control**; prior to the shutdown gas control shall be notified in advance of the shutdown schedule.
 - The affected **Distribution Regions Technical Services** to schedule remedial action on the distribution system and for notification of customers, such as transportation customers, etc.
 - UEG/wholesale customers and producers, when affected
- 4.1.9. To confirm arrangements and schedule of all shutdowns, prepare and distribute [Form 3506](#), *Notice of Shutdown / Operational Deviation* prior to the date of shutdown. If the date of the shutdown is likely to change, make a note to that effect on [Form 3506](#). Reach an agreement between the **Transmission and Storage Operations** organization, **Distribution Regions**, other affected parties, and **Gas Control** as to the minimum amount of time prior to the shutdown that a firm date must be set.
- 4.1.10. Each written plan (see Section 4.2) is reviewed by the appropriate responsible **Transmission or Storage Operations management personnel**.
- 4.1.11. Prior to the shutdown, give a copy of the written plan to and review with each person assigned to work on the project. When a contractor is providing work forces for a tie-in, give a copy of the plan to the **contractor's supervisors**. A pre-shutdown briefing is conducted by the **Transmission or Storage Operations management person** responsible for directing the operation.
- 4.1.12. Confirm shutdown arrangements by calling **Gas Control** and the affected **Distribution Region Technical Services** prior to the beginning of the shutdown.



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NOTE: **Gas Control** has the authority to approve and to disapprove shutdowns if conditions warrant.

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4.1.13. If gas is to be blown to atmosphere, notify public authorities (police, fire, Civil Aeronautics Administration [CAA] when appropriate, Air Quality Management District [AQMD], airport authorities, highway or street departments, etc.), and nearby businesses and residents, including local home-owner groups and associations. Also, notify interested Company departments.

4.1.14. Make regular phone or radio reports to the **Gas Control Supervisor** and affected **Distribution Regions** concerning job progress, such as status, estimated time of completion, valve operations, when delayed, when completed, etc.

4.1.15. Return the facility to normal service and coordinate with **Gas Control** to insure proper line pack and gas routing.

4.1.16. Document pressure prior to blowdown and complete [Form 3466, Reporting of Gas Blown to Atmosphere](#).

4.2. Written Plans

4.2.1. **Transmission and Storage Operations** develop written plans for handling planned shutdowns. Plans are specific and definitive in order to maintain well established operations.

4.2.2. The written plan for handling shutdowns under emergency conditions is of necessity general in nature because operations and conditions vary from one shutdown to another.

Written Plans — Field Operations

4.2.3. **Transmission and Storage Operations** provide their field operations personnel with a written plan for gas facility shutdowns delineating all critical activities associated with the shutdown.

4.2.4. The plan and subsequent job discussion includes, but is not limited to, the following information. The level of detail should be appropriate to the safe and efficient completion of the project:

- List of work to be accomplished prior to the shutdown.
- List of crucial equipment needed at the job site including hazardous materials cleanup equipment.

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- List of all concerned governmental agencies, affected **Distribution personnel**, other Company personnel, local businesses, and residents to be notified.
- Sequence of operations, including numbers and locations of valves to be operated and the estimated time when these operations will occur.
- Schematic of the section to be shut down with all pertinent valves and valve positions clearly labeled.
- List of all active customer and **Distribution** taps.

NOTE: All taps feeding a customer(s) or **Distribution Operations** systems must have a plan for an alternate feed that identifies who is responsible for the alternate feed.

- Schematics of the installation and removal sections.
- Detailed step-by-step procedure for all fire-control activities. See Gas [Standard 223.0165](#), *Controlled Fire Operations*.
- Detailed, step-by-step procedure for any purge performed. See Gas [Standard 182.0160](#), *Purging Pipelines and Components*.
- Plan for personnel protection using Lockout/Tag-out when required.
- Indicate any changes to telemetry (i.e., if data signals will be out of service or unavailable).

Written Plans — Gas Control

4.2.5. **Transmission and Storage Operations** provide **Gas Control** with a written plan for gas facility shutdowns which includes, but is not limited to, the following information:

- Sequence of operations, including numbers and locations of valves to be operated and the estimated time when these operations will occur
- Schematic drawing of the section to be shut down with all pertinent valves and valve positions clearly labeled.
- List of all active customer and **Distribution** taps.
- Schematic drawings of the installation and removal sections.

4.3. **Gas Control Shutdown Activities**

- 4.3.1. Review list of forecasted shutdowns.
- 4.3.2. Identify schedule conflicts.
- 4.3.3. Coordinate changes in planning schedules.
- 4.3.4. Advise **operating management** regarding gas handling arrangements.
- 4.3.5. Notify **Distribution Region Technical Services** as to whether their planned operations are deemed significant or not.
- 4.3.6. When a shutdown impacts the systems capability to accept full out-of-state supplies, a System Status Information report with shutdown details will be posted on the Company's on-line electronic communications system (**EEB**) as soon as the information is known as required by Remedial Measure 23.
- 4.3.7. As soon as it becomes evident that deliveries to a UEG customer are (or may be) affected, notify the appropriate **Energy Markets personnel**. Confirm shutdown prior to onset of actual work. For other major customers, notify **Commercial/Industrial**.
- 4.3.8. Before the shutdown, the **Gas Control Supervisor** works with **Transmission** to plan for alternate operations while arranging the transition to normal gas operations at the completion of a shutdown. During the shutdown, **Gas Control** operates the system.

NOTE: The **Gas Control Supervisor** has the authority to stop or change a shutdown during its progress.

4.4. **Emergency Shutdown Plans**

4.4.1. **Transmission and Storage Operations Responsibilities**

- 4.4.1.1. Each **Transmission and Storage Operations** organization's emergency shutdown plan is modified to meet the needs of each situation and to assure the facility is back in service as soon as possible.

4.4.1.2. In the event of a major, wide-spread emergency (i.e. earthquake, terrorist attack, flooding, firestorm, etc.) and a **GEC** and the **EOC** are both open and operational to respond to the event, the **GEC** should consider the following three (3) factors for alerting and involving the **Executive-in-Charge** at the **EOC** and **Gas Control** before implementing a large isolated section in the gas system unless Section 4.4.1.4 applies:

1. Size of Isolated Section

- The isolated section will impact 25,000 or more customers (restores)
- The isolated section could result in displacement of one million cubic feet or more per hour on the flow of gas required from the transmission system

2. Impacts to Sensitive/Critical Customers

- Health/Safety
 - Hospitals
 - Schools
 - Stadiums/Large Public Gathering Sites/Arenas/Sports Centers that can be used for evacuation shelters
 - Municipal Gas Systems (e.g., Long Beach Gas)
 - City/County/State Emergency Operation Centers that are open and running
- Economic
 - Non-core firm UEG customers
 - Refineries
 - Co-Generation Facilities (> 20 MW)
- Major Airports (e.g., Los Angeles International Airport (LAX), San Diego International Airport (SAN), John Wayne Airport (SNA), LA/Ontario International Airport (ONT), Bob Hope Airport (BUR))

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3. Requiring Inter-Region Coordination or Mutual Assistance

- Response across multiple operating organizations or with assistance from outside the Company required to implement the isolated section

4.4.1.3. The responsible **Transmission** or **Storage Operations management person** shall:

- Initiate a Message Center Report. See **183.0110**, *Field Procedure – Emergency Incidents – Transmission*.
- Consults with the **Gas Control Supervisor** to arrange the re-routing of gas flow and/or obtain permission to close off connections prior to shutting down.

4.4.1.4. **Transmission** or **Storage Operations** personnel may operate valves that affect gas flow without first clearing with the **Gas Control Supervisor** only when the responsible **Transmission** or **Storage Operations** management person at the site determines either of the following:

- Injury or death have occurred or is imminent
- Communications are not possible from the site and leaving the site would risk additional damage or injury. In such the **Gas Control Supervisor** is notified at the first opportunity directly or by **GEC** (if operational).

4.4.2. **Gas Control** Responsibilities

4.4.2.1. Re-routes supplies, as required.

4.4.2.2. Post outages impacting capacity in Envoy.

4.4.2.3. Notifies **Energy Markets**, when UEG and/or wholesale customers are affected.

5. EXCEPTION PROCEDURE

(See [GS 182.0004](#), *Exception Procedure for Company Operations Standards*)

- 5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

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Planning Shutdowns for Transmission and Storage	SCG:	223.0145
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5.2. An exception from a standard shall not be allowed unless [GS 182.0004](#), *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

6. OPERATOR QUALIFICATION COVERED TASKS

(See [GS 167.0100](#), *Operator Qualification Program, Appendix A, Covered Task List*)

- **Task 16.2** - 49 CFR 192.745 – Inspecting, operating, and maintaining transmission pipeline valves

7. RECORDS

7.1. Completed [Form 3506](#) and the completed procedure or work instructions package for the project that necessitated the shutdown must be retained for life of the pipeline asset.

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Planning Shutdowns for Transmission and Storage	SCG:	223.0145
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Company Operations Standard Gas Standard Gas Engineering

Purging Pipelines and Components	SDG&E:	G7909
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PURPOSE This gas standard provides the policy and procedures for safely purging natural gas pipelines above 60 psig. All company and contract employees shall follow these guidelines when purging pipeline systems.

1. POLICY AND SCOPE

- 1.1. Pipelines are purged to prevent the presence of a combustible mixture of gas and air. Failure to abide by the guidelines and procedures of this Gas Standard may result in serious or catastrophic consequences.
- 1.2. This procedure **does not include** purging operations that utilize air movers. For these purges, see [STANDARD G7910](#), *Purging Pipelines Using Air Movers For Cold Tie Operations*. For more specific purging information regarding purging into service medium pressure pipelines, see [STANDARD D7911](#), *Purging of Distribution Gas Lines of 60 PSIG*.
- 1.3. Written procedures shall be understood and approved by the Purging Operation Lead so as to assure the safe and successful completion of the job. See **Section 5.5** for further details about the written plan.
- 1.4. The Purging Operation Lead shall conduct a meeting, prior to a purging activity, to ensure all personnel engaged in purging operations understand the procedures involved. The Purging Operation Lead shall ensure that all employees and contractors involved in purging understand the potential hazards of improper operation. If changes in operations occur, all personnel will be informed of the changes before proceeding.
- 1.5. The Purging Operation Lead shall make the final determination on the adequacy of the purge before proceeding with any hot-work.
- 1.6. Limit access to the work area of the purging operation to only those persons who are necessary to perform the activity, keeping all-non-essential personnel and the public clear of harm's way.
- 1.7. Employees are responsible for adhering to company procedures and shall wear appropriate personal safety equipment during any and all duties performed as outlined in Rule 4100 of [Manual ESHSD-4100](#), *Gas Distribution and Transmission*.
- 1.8. Gas shall be vented to atmosphere without hazard to workers, public, and property. See **Section 5.3**.
- 1.9. Considerations must be given to the public with regard to objectionable noise and odor as well as any noise or pollution abatement requirements. Such considerations may include the use of noise suppression equipment, notification of law enforcement, Fire Department and Air Pollution Control District.

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- 1.10. All parts and equipment involved in the purging operation shall be in proper working condition and are visually inspected before use.
- 1.11. Adequate visual and/or radio communications shall be established between all work locations including the injection and venting points.
- 1.12. When purging out-of-service follow procedures stated in [STANDARD G8146](#), *Blowdown Time, Sizing, and Volume Calculations*, and [FORM 3466SD](#), *Reporting of Gas Blown to Atmosphere*, to account for the gas lost to atmosphere.
- 1.13. When purging into service a new steel pipeline, the pipeline must be odor conditioned (also known as seasoned or pickled) to minimize a reduction in the odor content of natural gas due to interaction of gas odorant with new steel. See [STANDARD G8132](#), *Odor Conditioning of New Steel Lines*.
- 1.14. Any deviation from this gas standard shall be reviewed and approved by **Gas Engineering - Pipeline Engineering**.

2. RESPONSIBILITIES AND QUALIFICATIONS

- 2.1. Only Company personnel qualified through Gas Operations Training may perform these operations. See [STANDARD G8113](#), *Operator Qualification Program*.
- 2.2. **Region Engineering Miramar** or **Transmission Operations Manager** shall prepare the written purging procedures. See **Section 5.5** for further requirements.
- 2.3. **Purging Operation Lead** shall be responsible for supervising purging operations. This lead shall have thorough technical knowledge and previous purging experience. This lead is also responsible for ensuring that all aspects of this standard are being followed.
- 2.4. **Distribution Region, Transmission District, and GTS Miramar** personnel performing purging activities shall be Operator Qualified. See [STANDARD G8113](#), *Operator Qualification Program* for requirements.
- 2.5. **Gas Operations Training - Skills** is responsible for training, qualification and all related certification and documentation for company and contract personnel.
- 2.6. **Field Employees** are responsible for ensuring that an approved fire extinguisher (minimum 40 BC) is readily accessible and its location known to all employees at the work site.
- 2.7. **Qualified Operators** are responsible to visually inspect all pressure control equipment prior to performing any pressure control operation. Do not use any damaged or defective equipment. Notify supervision if any defects are found.

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3. DEFINITIONS

- 3.1. **Blow-down** - To reduce pipeline pressure to atmospheric pressure by venting gas to atmosphere.
- 3.2. **CGI** – Combustible Gas Indicator
- 3.3. **Cursory Odor Sniff Test** - A quick release of natural gas into the atmosphere that is sniffed to determine if odorant is detectible by smell.
- 3.4. **Direct Purge** – The act of either directly purging gas with air or air with gas at high velocities without a nitrogen slug.
- 3.5. **Indirect Purge** – The act of either purging from gas to air or from air to gas with a nitrogen slug between the air and gas to prevent the formation of a combustible mixture.
- 3.6. **Orifice** – A reduced opening which reduces flow rate.
- 3.7. **Purge** - The act of removing all the air from a pipeline and replacing it with natural gas or removing all the natural gas from a pipeline and replacing it with air.
- 3.8. **Purging out of service** – (*Gas to Air/Nitrogen*) The process of replacing natural gas content in a pipeline with air/nitrogen by injecting air or nitrogen at sufficiently high flow rates.
- 3.9. **Purging into Service** – (*Air/Nitrogen to Gas*) The process of replacing air or nitrogen content in a pipeline with natural gas by injecting natural gas at sufficiently high flow rates.
- 3.10. **Purging Operation Supervisor** – The designated trained and knowledgeable supervisor responsible for gas handling operations, including purging.
- 3.11. **Slug** – As it relates to this standard, is a quantity of nitrogen gas injected between the gas and air during an indirect purge. The slug moves through the pipe as a distinct mass to prevent mixing of the gas and air.
- 3.12. **Total Displacement Purge** – The act of purging from gas to air or air to gas by injecting an amount of nitrogen slightly greater than the entire internal volume of the pipeline segment or facility to be purged.

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3.13. **BC** – Fire extinguisher rating effective for flammable liquid fires and “live” electrical equipment.

4. REQUIREMENTS PRIOR TO PURGING

4.1. **ISOLATION** - Completely isolate the piping segment to be purged from the system.

4.1.1. Isolation may be accomplished by one or more methods including the use of blind flanges, closing valves, placing blanking discs between flanges, pressure control fittings or physically disconnecting laterals or other sources of gas.

4.1.2. Squeezing of PE pipe may be an acceptable means of isolation for purging. Only Company approved squeeze tools shall be used. See [STANDARD D7279, Squeezing Polyethylene \(PE\) Pipe – ½” Through 8”](#).

4.1.3. If valves are used to isolate the section to be purged from the pressurized system, they should be verified to stroke properly and not to leak.

4.1.4. A thorough physical check shall be made to ensure that isolation is prepared as planned and free of leakage prior to the start of the purging operation.

4.2. **NITROGEN** - When using nitrogen as a separating medium (slug) or for Total Displacement Method, practicality, availability and economics determine whether to use cylinders (bottles) or a tank truck. A tank truck is normally the less costly option when a large volume of nitrogen is required.

4.2.1. Standard cylinders typically have 250 standard cubic feet (scf) of nitrogen at 2265 psig.

4.2.2. If an Indirect Purge is required, use **Table A3** in Appendix A to determine the minimum number of cylinders required. If the use of a nitrogen truck is desired, such as when large volumes are required, see **Table A5** in **Appendix A** to obtain required nitrogen volumes.

4.2.3. If a Total Displacement Purge is required or desired, use **Table A4** in **Appendix A** to determine the minimum number of cylinders required for a Total Displacement Purge.

4.2.4. Nitrogen Gas Safety - Be aware that the accumulation of large quantities of nitrogen gas can present an asphyxiation hazard to personnel. In trenches or confined spaces where nitrogen is being purged and can accumulate, keep ventilated and check for oxygen level before personnel enters the space.

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5. PROCEDURE

5.1. Selection of Purging Method

5.1.1. **Purging Operation Supervisor** must understand and approve the written procedures to provide a safe and successful completion of the purging operation. See **Section 5.5** for further details about the written plan. **Using Table 1 below, select the proper purging method based on the combination of pipe diameter and length of the segment to be purged.**

5.1.2. The indirect method can be substituted for the direct method.

Diameter (in)	Length (ft)	Purging Method
$D \leq 4$	Any	Direct (Section 5)
$D \geq 6$	$L < 500$	Direct (Section 5)
$D \geq 6$	$L \geq 500$	Indirect (Section 7)

Table 1

The Total Displacement Method (**Section 3.12**) shall be used when:

- A potential hazard exists due to the presence of liquids or solids
- A potential hazard exists due to a complex piping situation, such as with stubs, or in compressor and regulator stations
- Permanently abandoning a pipeline or main that is not free of liquids or solids, or if required by the permitting agency. (See [STANDARD D7381](#), *Abandonment or Inactivation of Gas Distribution Pipelines*, or [STANDARD T7381](#), *Abandonment, Conversion and Reinstatement of Transmission Pipelines*).

5.2. Sources of Ignition

5.2.1. Eliminate all sources of ignition. Extinguish any open flames (smoking is prohibited). Do not carry any items designed to produce sparks such as but not limited to: matches, cigarette lighters, welding torch igniters, cell phones or any other electrical devices in the immediate vicinity any time while working in a gaseous atmosphere. See [Manual ESHSD-4100](#), *Gas Distribution and Transmission*, and [STANDARD G8169](#), *Prevention of Accidental Ignition of Natural Gas*.

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- 5.2.2. When purging, especially with old piping, it shall be kept in mind that purging removes only gaseous or volatile materials. Undetected liquid or solid combustibles can be ignited by sparks carried back into a purged pipeline when it is cut. Take necessary precautions to ensure removal of difficult to detect combustibles. Consider purging using the Total Displacement Method with nitrogen if the presence of liquids or solids exists. See **Section 3.12** for definition of Total Displacement Purge.
- 5.2.3. Consider purging with the Total Displacement Method with nitrogen if the presence of liquids or solids exists. See **Section 3.12** for definition of Total Displacement Purge.
- 5.2.4. Care shall be taken to avoid static electrical discharge before, during and after purge by grounding all machinery and equipment where static electricity might accumulate. Pipelines are bonded or grounded before purging, cutting, or disconnecting in accordance with [STANDARD G8169, Prevention of Accidental Ignition of Natural Gas](#). Before severing or disconnecting a steel pipe, a bond wire must be attached to the metallic pipe at two points to provide a connection across the proposed severance or disconnection which connects both sides of the remaining pipe. For purging Polyethylene (PE) pipe, see [STANDARD G8169, Prevention of Accidental Ignition of Natural Gas](#).

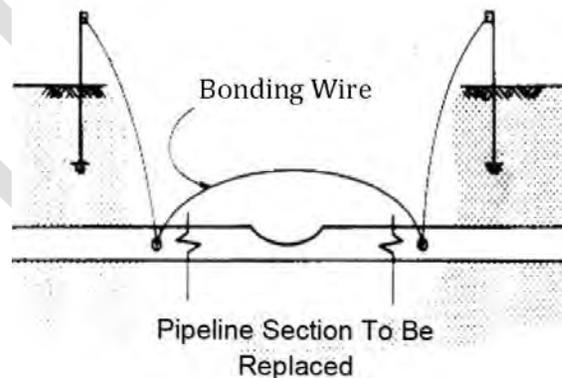


Figure 0. – Bonding wire placed across proposed severance or disconnection

- 5.2.5. Cathodic protection rectifiers shall be turned off.

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5.3. Venting

- 5.3.1. See **Table A1** for vent stack sizing.
- 5.3.2. The steel vent stack should consist of a full opening tap in the pipeline to be purged.
- 5.3.3. When a vent valve is used, it shall be full opening.
- 5.3.4. When selecting venting locations, care is taken to prevent accidental ignition during purging operations. Avoid venting under or in close proximity to overhead power lines, per [STANDARD G8183 – Purging Operations – Minimum Distance Between Purging Stack and Ignition Sources](#).
- 5.3.5. Never discharge purging medium through a plastic vent pipe.
- 5.3.6. Any project that requires gas blown to atmosphere will build time into the project schedule to reduce methane consistent with safe operations and consider alternative potential sources of supply to reliably serve customers and maintain feasibility. Operating pressure should be reduced to the lowest operationally feasible level in order to minimize methane emissions before non-emergency venting of high-pressure distribution (above 60 psig), transmission and underground storage infrastructure consistent with safe operations. and whenever practicable, work should be bundled to prevent multiple venting of the same piping.
- 5.3.7. If a new Transmission pipeline assembly is enclosed with wet canvases, the assembly may be directly purged into service using one canvas end as a vent provided that:
 - When purging through a wet canvas, the canvas opening should be approximately $\frac{1}{3}$ of the cross-section of the pipe. The opening is at the bottom when purging into service. See [STANDARD D7114, Pipe End Closures](#).
- 5.3.8. If a steel vent stack is to be assembled on an existing blow-off that does not meet size and full opening description, **Gas Engineering - Pipeline Engineering**, will determine the adequacy of the blow-off.

5.4. Planning a Purge

- 5.4.1. Use **Table A1** in **Appendix A** to obtain the standard purging parameters for specific pipe diameters:

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- These parameters include the standard injection fittings, injection pressures, vent sizes and flow rates.
 - If orifices are to be utilized, use the required minimum flow rates from **Table A1**. Select the appropriate orifice size and inlet pressure based on required flow rates.
 - Place the orifice immediately upstream of the injection fitting to eliminate any unplanned pressure drop.
 - Orifices are normally placed in screwed orifice unions, but a tapped abandonment fitting can also be used. Injection and bypass fittings selected shall not have an internal diameter smaller than the hose or orifice to be used. See **Figure 6** for typical orifice set-up.
- 5.4.2. When using an orifice, the pressure gauge to measure the minimum required pressure should be installed just upstream of the orifice. The tapped diameter when using an abandonment fitting needs to be equal to or greater than the orifice size.
- 5.4.3. When using a 50 foot hose to measure and maintain minimum flow rates as required in **Table A1**, the pressure gauge must be installed at the upstream end of the 50 foot hose connected to the injection point.
- 5.4.4. Use **Table A2** in **Appendix A** to obtain an approximate arrival time at particular lengths of pipe when using a standard set up. When purging by the indirect method, this approximate time indicates the arrival of the nitrogen slug.
- 5.4.5. When using an Indirect Purge (with a slug of nitrogen) it is important to maintain the minimum slug speed (minimum injection flow rate) as indicated by the use of **Table A1** to minimize the mixing of the gas interface to maintain the slug.
- 5.4.6. When purging out of service using an air compressor, make certain that the selected compressor is rated with at least 15% more flow rate capacity than the minimum flow rate listed in **Table A1**.
- 5.4.7. When possible, purge from air/nitrogen to gas downhill, and purge from gas to air/nitrogen uphill.
- 5.4.8. A piping system containing loops or branches requires a detailed evaluation to ensure each pipe section is properly isolated and purged which typically requires isolating and purging in stages.

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5.5. **Written Plan**

- 5.5.1. An approved written plan should be available for all purging procedures.
- 5.5.2. Service lines and small diameter pipelines can be purged using the general procedures of this gas standard as the written plan. More complex purging operations require a specific detailed written plan.
- 5.5.3. The written plan should include, but is not limited to, the required purging method, location of isolation points, injection set up, injection pressures and flow rates, venting location and stack size, operational sequences, an equipment list (Combustible gas indicator, air compressor, etc.) and provisions for a communication system.

5.6. **Non-Typical Purging Operations**

- 5.6.1. When purging a service that has an Excess Flow Valve installed; see [STANDARD G7643](#) *Excess Flow Valve (EFV) - Installation and Operation*.
- 5.6.2. For Abandonment of Distribution Mains and Services see [STANDARD D7110](#), *Abandonment of Gas Services and Gas Light Tap Assemblies* and [STANDARD D7381](#), *Abandonment or Inactivation of Gas Distribution Pipelines* for diameters and lengths of piping that do not require purging prior to abandonment.
- 5.6.3. Air Movers may be used for purging large diameter ($\geq 8''$) pipelines out of service; see [STANDARD G7910](#), *Purging Pipelines Using Air Movers For Cold Tie Operations*.
- 5.6.4. If a standard indirect purge is not practical or possible, in cases such as long pipeline lengths yielding unreasonable operation times or if the use of larger injection fittings and/or vents is desired, contact **Gas Engineering - Pipeline Engineering** for analysis.
- 5.6.5. All non-standard purges require a written plan approved by **Gas Engineering - Pipeline Engineering**.

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6. PURGING OUT OF SERVICE USING THE DIRECT PURGE METHOD (GAS TO AIR)

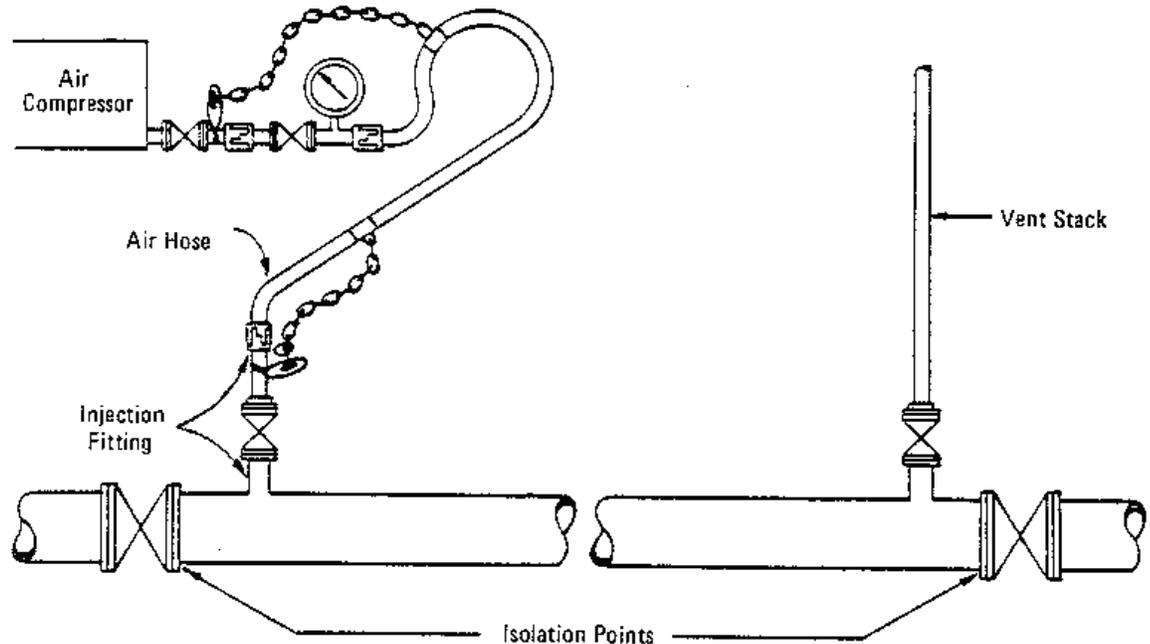


Figure 1. - Arrangement for Directly Purging Gas from Pipelines.

- 6.1. The Purging Operation Lead reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.
- 6.2. Remove all ignition sources in accordance with **Section 5.2**.
- 6.3. Isolate section of line to be purged. See **Section 4.1**.
- 6.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, which is a minimum of 7 ft. See **Figure 1**.
- 6.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. Connect air hose and valve to pressure gauge. See **Figure 1**.
- 6.6. Connect gauge and valve end of air hose to air compressor and attach other end of hose to injection fitting. See **Figure 1**.
- 6.7. Open valve on vent stack and blow down line.

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- 6.8. With the air compressor valve open, gradually open the valve on injection fitting and inject air. Inject at or above the minimum injection pressure, see **Table A1**. Injection of air shall be continued without interruption until the pipeline is purged of all gas. Control pressure with valve attached to compressor end of air hose. See **Figure 1**.
- 6.9. Stop injection of air when pipeline is purged of all gas. Use approved CGI device to determine if pipeline is 100% purged of all gas. See [STANDARD G8220](#), *GMI Gasurveyor SCG PPM Combustible Gas Indicator Operating Procedures*.

INTERNAL

7. PURGING INTO SERVICE USING THE DIRECT PURGE METHOD (AIR/NITROGEN TO GAS)

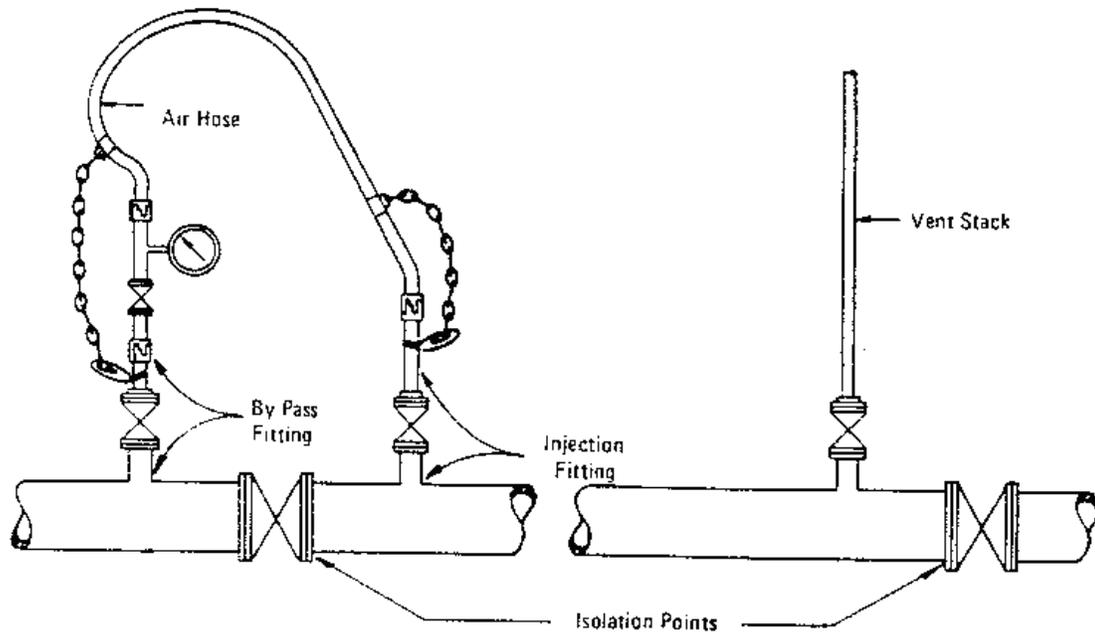


Figure 2 - Arrangement for Directly Purging Pipelines into Service.

- 7.1. The Purging Operation Lead reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.
- 7.2. Remove all ignition sources in accordance with **Section 5.2**.
- 7.3. Isolate section of line to be purged. See **Section 4.1**.
- 7.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, which is a minimum of 7 ft. See **Figure 2**.
- 7.5. Install injection fitting as close as practical to, but not more than 5 feet away from the injection end of pipeline. See **Figure 2**. If available, gas may be injected by opening a line valve instead of using a bypass, however, contact **Gas Engineering - Pipeline Engineering** to obtain the downstream pressure needed to control the purge.
- 7.6. If needed, install bypass fitting on live pipeline for gas source. See **Figure 2**.

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- 7.7. Connect gauge and valve to bypass fitting. Connect an air hose or pressure hose from pressure gauge end to injection fitting. See **Figure 2**.
- 7.8. Open valve on vent stack.
- 7.9. Gradually open valve on injection fitting and inject gas. Inject at or above the minimum injection pressure. Injection of gas shall be continued without interruption until the pipeline is purged of all air. Control pressure with valve attached to bypass fitting. See **Figure 2**.
- 7.10. Stop injection of gas when pipeline is purged of air. Use approved CGI device to determine if pipeline is 100% gas. Use approved CGI device to determine if pipeline is 100% purged of all gas. See [STANDARD G8220](#), *GMI Gasurveyor SCG PPM Combustible Gas Indicator Operating Procedures*.
- 7.11. A ***cursory odor sniff test*** (a quick release of natural gas into the atmosphere that is sniffed to determine if odorant is detectible by smell) shall be performed immediately after the purging process and verifying 100% gas is obtained.
- 7.12. Direct purging of gas services less than 2” steel can be accomplished using a service tee or pin-off tee as the purge source.

8. PURGING OUT OF SERVICE USING THE INDIRECT PURGE METHOD (GAS TO AIR)

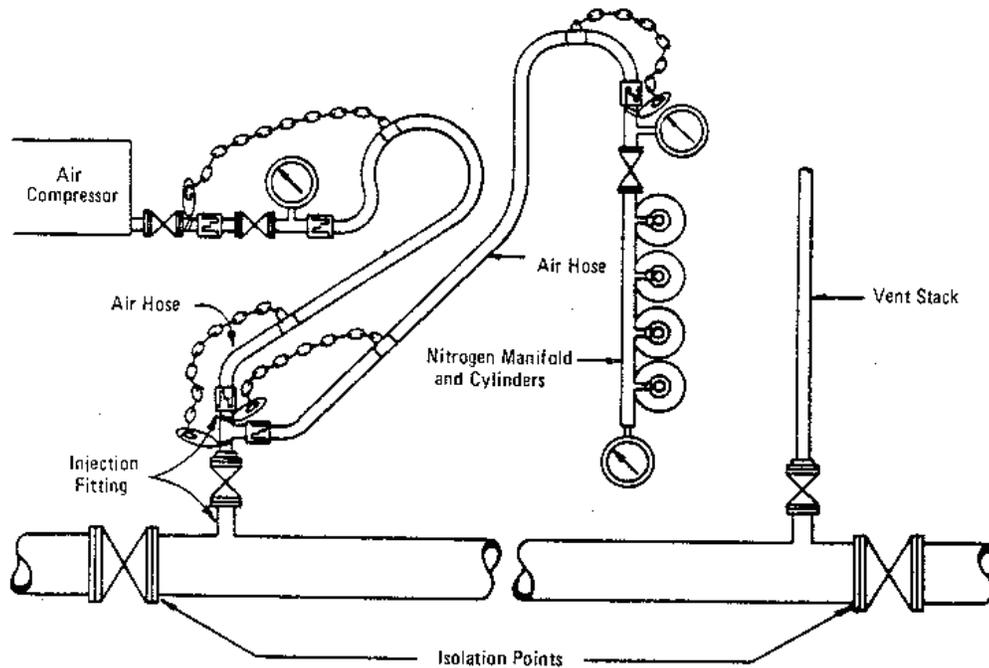


Figure 3. Arrangement for Purging Out of Service using Indirect Method

- 8.1. The Purging Operation Lead reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.
- 8.2. Remove all ignition sources in accordance with **Section 5.2**.
- 8.3. Isolate section of line to be purged. See **Section 4.1**.
- 8.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, which is a minimum of 7 ft. See **Figure 3**.
- 8.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. See **Figure 3**.
- 8.6. Connect gauge and valve to air compressor and attach hose from the other end of the injection fitting. See **Figure 3**.

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- 8.7. If nitrogen cylinders are to be used, connect the nitrogen cylinders indicated in **Table A3** to the manifold. Close valve on manifold and open valves on nitrogen cylinders. See **Figure 3**.
- 8.8. Connect manifold hose or pressure hose to injection fitting. See **Figure 3**.
- 8.9. Open valve on vent stack and blow-down the pipeline.
- 8.10. Once the pipe segment has been blown down, gradually open valve on injection fitting.

Note: Verify this valve is open to prevent damage to the gauge on the manifold.

- 8.11. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure as indicated in **Table A1** to maintain minimum flow rate controlling pressure with the manifold valve. See **Figure 3**.
- 8.12. Begin injecting air as soon as the minimum gauge pressure of nitrogen, cannot be maintained. Close valve on nitrogen manifold immediately after air injection has started. Air must be injected at or above the minimum gauge pressure as indicated in **Table A1** to maintain minimum flow rate. Control pressure with valve attached to compressor end of air hose. See **Figure 3**.
- 8.13. Stop injection of air when pipeline is 100% purged of all gas. Use approved CGI device to determine if pipeline is 100% purged of all gas. See [STANDARD G8220](#), *GMI Gasurveyor SCG PPM Combustible Gas Indicator Operating Procedures*.

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9. PURGING INTO SERVICE USING THE INDIRECT PURGE METHOD (AIR TO GAS)

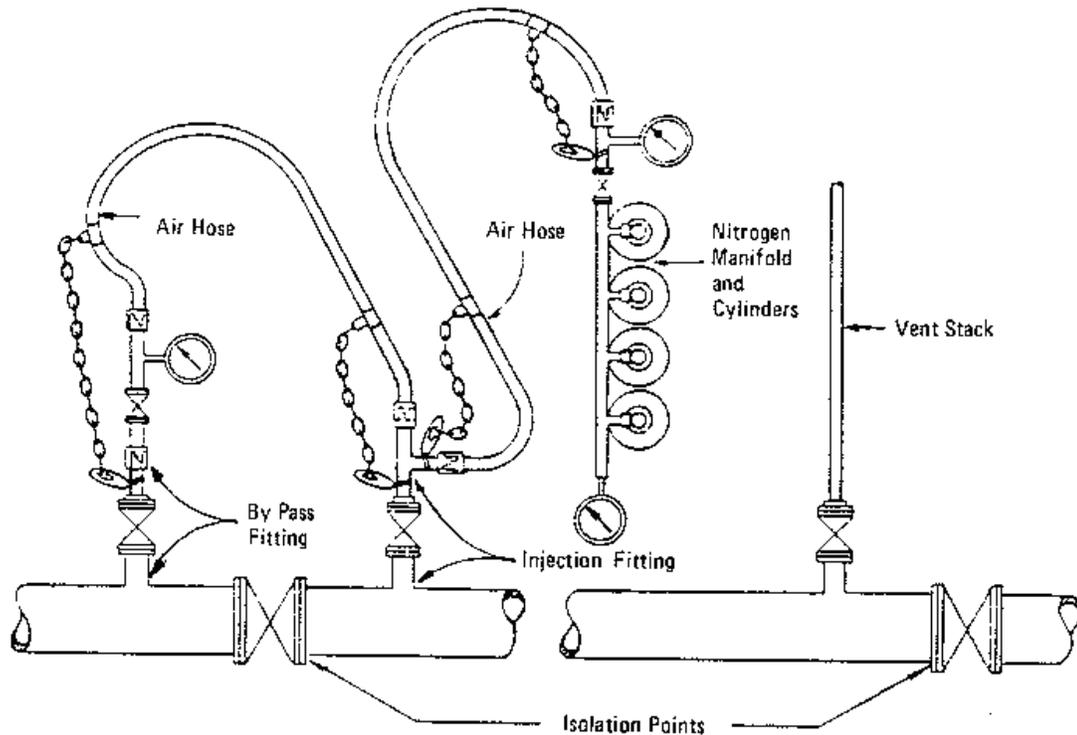


Figure 4. Arrangement for Purges into Service using Indirect Method

- 9.1. The Purging Operation Lead reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.
- 9.2. Remove all ignition sources in accordance with **Section 5.2**.
- 9.3. Isolate section of line to be purged. See **Section 4.1**.
- 9.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, which is a minimum of 7 ft. See **Figure 4**.
- 9.5. Install injection fitting as close as practical, but not more than 5 feet from the injection end of pipeline. See **Figure 4**. If available, gas may be injected by opening a line valve instead of using a bypass, however, contact **Gas Engineering - Pipeline Engineering** to obtain the downstream pressure needed to control the purge.
- 9.6. If needed, install bypass fitting on pipeline as a gas source. See **Figure 4**.

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- 9.7. Connect gauge and valve to bypass fitting. Connect an air hose or pressure hose from pressure gauge end to injection fitting. See **Figure 4**.
- 9.8. Connect nitrogen cylinders as indicated in **Table A3** to the manifold. Close valve on manifold and open valves on nitrogen cylinders.
- 9.9. Connect manifold hose or high pressure hose to injection fitting. See **Figure 4**.
- 9.10. Open valve on vent stack.
- 9.11. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure as indicated in **Table A1** to maintain minimum flow rate controlling pressure with the manifold valve. See **Figure 4**.
- 9.12. Begin injecting gas as soon as the minimum gauge pressure of nitrogen, cannot be maintained. Close valve on nitrogen manifold immediately after gas injection has started. Gas must be injected at or above the minimum gauge pressure as indicated in **Table A1** to maintain the minimum flow rate. Control pressure with valve attached to bypass fitting. See **Figure 4**.
- 9.13. Stop injection of gas when pipeline is purged of air. Use approved CGI device to determine if pipeline is 100% purged of all gas. See [STANDARD G8220](#), *GMI Gasurveyor SCG PPM Combustible Gas Indicator Operating Procedures*.
- 9.14. A *cursorry odor sniff test* (a quick release of natural gas into the atmosphere that is sniffed to determine if odorant is detectible by smell) shall be performed immediately after the purging process and verifying 100% gas is obtained.

10. PURGING OUT OF SERVICE USING THE TOTAL DISPLACEMENT PURGE METHOD (GAS TO NITROGEN)

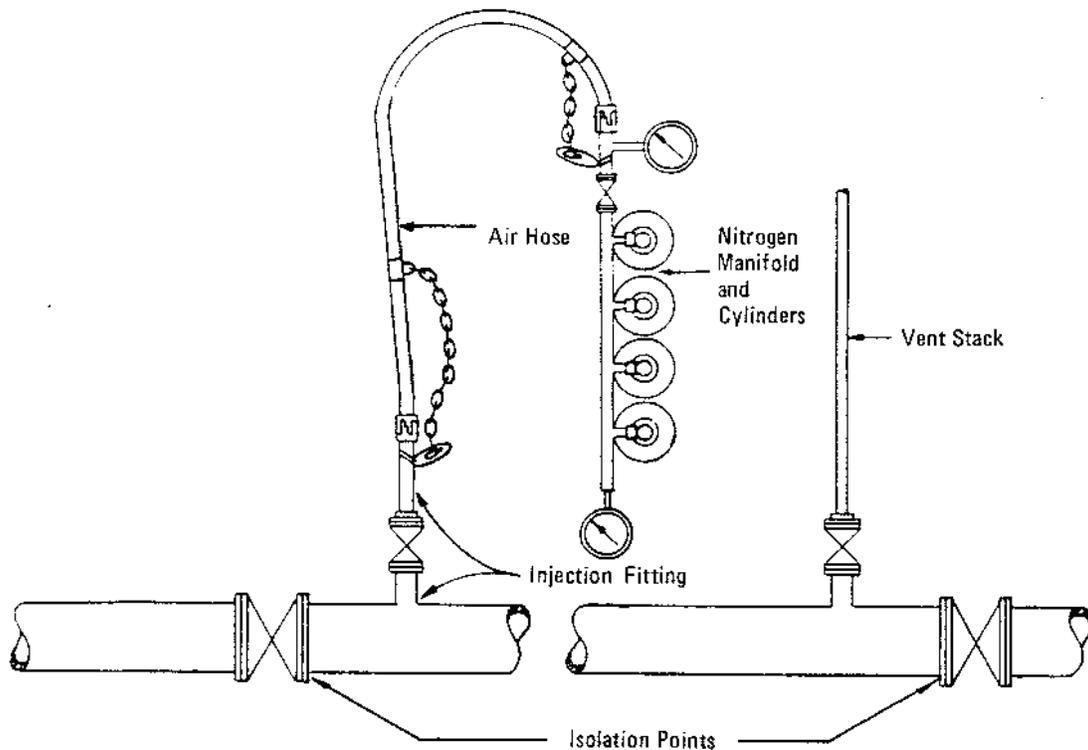


Figure 5. Arrangement for Purging Out of Service using Total Displacement Method

- 10.1. The Purging Operation Lead reviews the approved Written Plan and takes necessary actions to ensure all company policies are adhered to. See **Section 5.5**.
- 10.2. Remove all ignition sources in accordance with **Section 5.2**.
- 10.3. Isolate section of line to be purged. See **Section 4.1**.
- 10.4. If a properly sized vent is not available, install one as close as practical, but not more than 5 feet from venting end of the pipeline. Stack must extend to a safe location, which is a minimum of 7 ft.
- 10.5. Install injection fitting as close as practical from the injection end of pipeline, but not more than 5 feet from the injection end of pipeline. See **Figure 5**.
- 10.6. If nitrogen cylinders are to be used, connect the nitrogen cylinders to the manifold. Close valve on manifold and open valves on nitrogen cylinders. See **Figure 5**.

- 10.7. Connect manifold hose or pressure hose to injection fitting. See **Figure 5**.
- 10.8. Open valve on vent stack and blow-down the pipeline.
- 10.9. Open valve on injection fitting. Be sure this valve is open to prevent damage to the gauge on the manifold. See **Figure 5**.
- 10.10. Inject nitrogen by gradually opening manifold valve. Inject at or above the minimum injection pressure as indicated in **Table A1** to maintain minimum flow rate controlling pressure with the manifold valve. See **Figure 5**.

NOTE: When abandoning a pipeline using the Total Displacement Method stop injection once pipeline is completely purged of gas then proceed in capping the pipe.

- 10.11. Stop injection of nitrogen when pipeline is 100% purged of all gas. Use approved CGI device to determine if pipeline is 100% purged of all gas. See [STANDARD G8220](#), *GMI Gasurveyor SCG PPM Combustible Gas Indicator Operating Procedures*.
- 10.12. Sections with pipe left with 100% nitrogen must be stenciled “Nitrogen”. Also adjoining valves must be stenciled “Nitrogen”.

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11. TYPICAL ORIFICE SET UP (DIRECT PURGE)

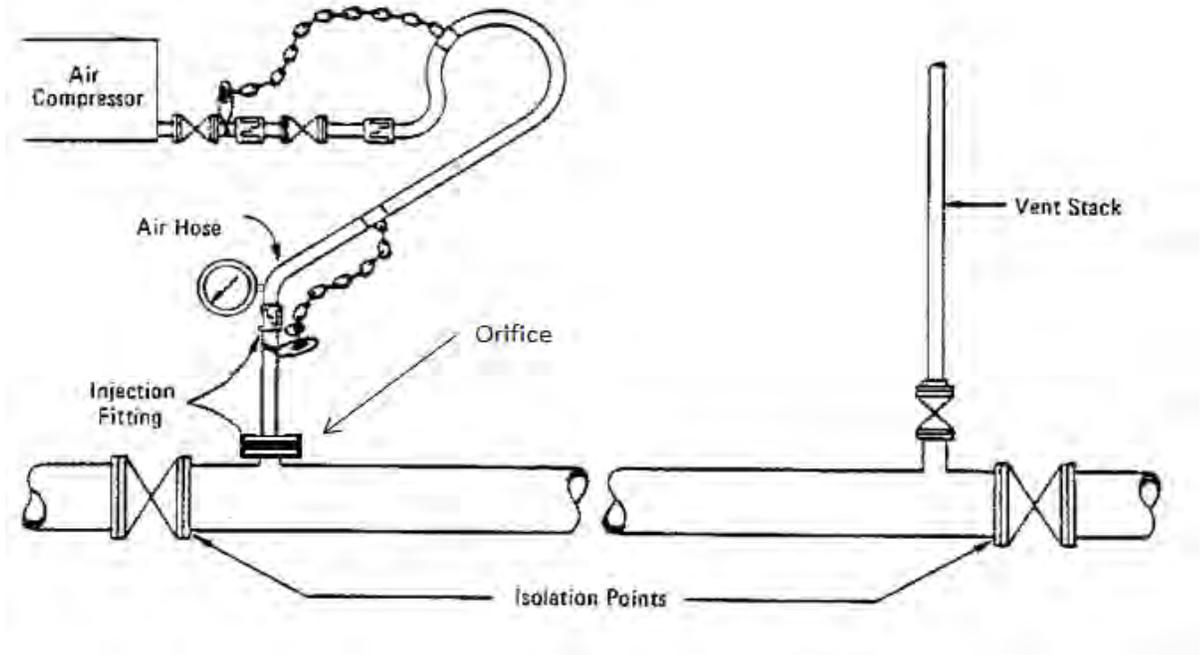


Figure 6. Direct Method with Orifice and pressure gauge relocated closer to orifice. (Direct Purging)

12. OPERATOR QUALIFICATION COVERED TASKS

(See [STANDARD G8113](#), *Operator Qualification Program, Appendix A, Covered Task List*)

- Task 07.01-1651 - Purge Direct: Flammable or Inert Gas
- Task 07.02-1651 - Purge Indirect: Flammable or Inert Gas

13. EXCEPTION PROCEDURE

(See [STANDARD G7007](#), *Exception Procedure for Company Operations Standards*)

- 13.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

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13.2 An exception from a standard shall not be allowed unless [GS G7007](#), *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by G7007.

14. RECORDS

Not Applicable.

15. APPENDICES

15.1. Appendix A

INTERNAL

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APPENDIX A

**Table A1
Minimum Equipment Requirements for Purging Pipeline**

Nominal Pipe Diameter (inches)	Hose Diameter ID** (inches)	Minimum Nominal Vent Stack Size*** (inches)	Minimum Gauge Pressure *		Minimum Injection Flow Rate (SCFM)
			Gas (psig)	Nitrogen/Air (psig)	
4 and less	3/4	3/4	3	3	11
6	3/4	1 -1/2	6	8	29
8	3/4	1 -1/2	15	18	56
10	3/4	2	28	35	96
12	3/4	3	47	59	149
16	1 1/4	3	19	26	273
18	1 1/4	4	28	40	367
20	1 1/4	4	41	55	489
22	1 1/4	4	55	75	615
26	2	6	21	30	930
30	2	6	32	45	1331
34	2	6	45	65	1821
36	2	6	54	77	2117

* Pressures listed are based on placing a pressure gauge on 50 feet of hose at the upstream end of the injection point. Shorter distances yield greater injection rates and shorten purge durations. Contact **Gas Engineering – Pipeline Engineering** if hose distances are greater than 50 feet.

** If it's necessary to use a larger diameter hose larger specified, contact **Gas Engineering - Pipeline Engineering** for the lower required minimum gauge pressure.

*** For vents in excess of 10 ft. long, go to next larger pipe size. Multiple vents stacks are allowed if a single vent stack does not meet the minimum diameter requirements. The total internal flow area of the multiple vents needs to be greater than the internal flow area of the required vent size. Contact **Gas Engineering - Pipeline Engineering** for guidance on correct combinations of vent stacks.

Note: The diameter of manifolds should be at least equal to the size of the hose diameter required for purging.

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Table A1*
Measuring Rates through Orifices
Use these figures for measuring the injection rates while purging.
(Note: All Hose and Orifice Sizes are Internal Diameters)

Inject Rate (cfm)	Pressure Upstream of Orifice (psig) (Note: All Hose and Orifice Sizes are Internal Diameters)									
	Orifice Size (inches)									
	3/8		1/2		5/8		3/4		7/8	
	Gas	N ₂ Air	Gas	N ₂ Air	Gas	N ₂ Air	Gas	N ₂ Air	Gas	N ₂ Air
10										
20										
40	7	12								
60	19	26	5	8						
80	30	39	11	16	2	5				
100	41	53	18	24	6	10				
120	52	67	25	31	10	14				
140	63	80	31	39	14	19				
160	75	94	38	47	19	24				
180	86	107	44	54	23	29				
200	97	121	51	62	27	34				
220	106	136	53	70	29	39	17	22	9	13
240	117	150	59	78	33	44	20	26	11	15
260	128	163	66	85	37	49	22	29	13	18
280	139	177	72	93	41	54	25	33	15	20
300	150	191	78	101	45	59	28	36	17	23
320	161	205	84	109	49	64	31	39	19	25
340	172	218	90	116	53	69	34	43	21	28
360	183	232	97	124	57	74	37	46	24	30
380	194	246	103	132	61	78	40	50	26	33
400	205	259	109	139	65	83	43	53	28	35
420	216	273	115	147	69	88	45	56	30	38
440	227	287	121	155	73	93	48	60	32	40
460	238	301	128	163	77	98	51	63	34	43
480	249	314	134	170	81	103	54	67	36	45
500	260	328	140	178	85	108	57	70	39	48
550	286	362	156	197	95	120	61	79	41	53
600	314	397	171	217	105	133	68	87	46	59
650	341	431	187	236	115	145	75	96	51	65
700	369	465	202	255	125	157	82	104	56	71
750	396	500	218	275	135	170	89	113	62	77
800	423	534	233	294	145	182	95	121	67	83
850	451	568	249	313	155	194	102	130	72	90
900	478		264	332	165	206	109	138	77	96
950	506		280	352	175	219	116	147	82	102
1000	533		295	371	185	231	123	155	87	108
1050	560		311	390	195	243	130	164	92	114
1100	588		326	410	205	256	137	172	97	120
1150			342	429	215	268	144	181	102	126
1200			357	448	225	280	151	189	107	133
1250			373	468	235	293	158	198	113	139
1300			388	487	245	305	164	206	118	145
1350			404	506	255	317	171	215	123	151
1400			419	525	265	329	178	223	128	157
1450			435	545	275	349	185	232	133	163
1500			450	564	285	354	192	240	138	170
1550			466	583	295	366	199	249	143	176
1600			481		305	379	206	257	148	182
1650			497		315	391	213	266	153	188
1700			512		325	403	220	274	158	194
1750			528		335	416	227	283	164	200
1800			543		345	428	233	291	169	206
1850			559		355	440	240	300	174	213
1900			574		365	452	247	308	179	219
1950			590		375	465	254	317	184	225
2000					385	477	261	325	189	231
2050					395	489	268	334	194	237
2100					405	502	275	342	199	243

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Table A1 (continued)*
Measuring Rates through Orifices
 Use these figures for measuring the injection rates while purging.
 (Note: All Hose and Orifice Sizes are Internal Diameters)

Inject Rate (cfm)	Pressure Upstream of Orifice (psig)							
	(Note: All Hose and Orifice Sizes are Internal Diameters)							
	Orifice Size (inches)							
	1-1/8		1-3/8		1-1/2		1-3/4	
	Gas	N ₂ Air	Gas	N ₂ Air	Gas	N ₂ Air	Gas	N ₂ Air
10								
20								
40								
60								
80								
100								
120								
140								
160								
180								
200								
220		2						
240		3						
260	2	5						
280	3	6						
300	4	8						
320	5	9						
340	7	11						
360	8	12						
380	9	14						
400	11	15						
420	12	17						
440	13	18						
460	14	20						
480	16	21						
500	17	23						
550	20	26	9	13				
600	23	30	11	15				
650	26	34	13	18				
700	29	38	15	20				
750	32	41	17	23				
800	35	45	19	25				
850	39	49	22	28				
900	42	53	24	30				
950	45	56	26	33				
1000	48	60	28	35	18	26	9	15
1050	51	64	30	38	20	28	10	17
1100	54	68	32	40	21	30	11	18
1150	57	71	34	43	23	32	13	20
1200	61	75	37	45	25	34	14	21
1250	64	79	39	48	26	36	15	23
1300	67	83	41	50	28	38	16	24
1350	70	86	43	53	30	40	17	26
1400	73	90	45	55	31	42	19	27
1450	76	94	47	58	33	44	20	29
1500	80	98	50	60	35	47	21	30
1550	83	101	52	63	36	49	22	32
1600	86	105	54	65	38	51	23	33
1650	89	109	56	68	39	53	25	35
1700	92	113	58	70	41	55	26	36
1750	95	116	60	73	43	57	27	38
1800	98	120	62	75	44	59	28	39
1850	102	124	65	78	46	61	29	41
1900	105	128	67	80	48	63	31	42
1950	108	131	69	83	49	65	32	44
2000	111	135	71	85	51	67	33	45
2050	114	139	73	88	53	69	34	47
2100	117	143	75	90	54	71	35	48

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Table A2**

Pipe Size (in.)	Estimated Duration of Purge (min) (at the minimum injection rates shown in Table A1)									
	Length of Pipe (feet)									
	1000	2000	3000	4000	5000	6000	8000	10000	20000	50000
4 and less	8	16	24	32	40	48	64	80	160	400
6	8	16	23	31	39	46	62	77	154	385
8	7	14	20	27	34	40	54	67	134	334
10	6	12	18	25	31	37	49	61	122	303
12	6	11	17	22	28	34	45	56	111	278
16	5	10	15	19	24	29	38	48	96	238
18	5	9	14	18	23	28	37	46	91	228
20	5	9	13	17	22	26	34	43	85	213
22	4	8	13	16	21	25	33	41	82	205
26	4	8	12	15	19	23	30	38	76	189
30	4	7	11	14	18	21	28	35	70	176
34	4	7	10	13	17	20	27	33	66	164
36	3	7	10	13	16	19	26	32	64	159

The time for lengths not shown may be interpolated. For assistance with interpolation, contact **Gas Engineering - Pipeline Engineering.

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Gas Engineering**

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**Table A3
Number of Nitrogen Cylinders (250 Cubic Feet Each)
Required To Form the Minimum Slug Size in a Pipeline
Indirect Method**

Pipe Size (inches)	Pipe Length (ft)									
	500**	1000	2000	3000	4000	5000	7500	10,000	20,000	50,000
4	1	1	1	1	1	1	1	1	1	1
6	1	1	1	1	1	1	1	1	1	2
8	1	1	1	1	1	1	1	1	2	2
10	1	1	1	1	1	2	2	2	2	3
12	1	1	2	2	2	2	2	2	3	4
16	2	2	2	2	3	3	3	4	5	7
18	2	2	3	3	3	4	4	5	6	9
20	2	3	3	4	4	4	5	6	7	11
22	3	3	4	4	5	5	6	7	9	13
26	4	4	5	6	6	7	8	9	12	18
30	5	5	7	8	8	9	11	12	16	24
34	6	7	9	11	12	13	15	17	23	35
36	7	8	10	12	13	15	17	19	26	39

Pipelines less than 500 ft. may be displaced directly with air or gas. Refer to **Table 1 "Purging Method" for additional guidance or when indirect purge is to be used.



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**Table A4
Number of Nitrogen Cylinders (250 Cubic Feet Each) Required To Fill Pipeline
Total Displacement Method**

Pipe Size (inches)	Pipe Length (ft)										
	500	1000	2000	3000	4000	5000	6000	8000	10,000	20,000	50,000
2	1	1	1	1	1	1	1	1	2	3	5
3	1	1	1	1	1	2	2	2	3	5	11
4	1	1	1	2	2	3	3	4	5	9	19
6	1	1	2	3	4	5	6	8	10	19	*42
8	1	2	4	5	7	9	10	13	17	*33	*74
10	2	3	6	8	11	13	16	21	26	*52	*116
12	2	4	8	11	15	19	22	29	*37	*73	*164
16	3	6	12	17	23	28	*34	*45	*56	*112	*254
18	4	8	15	22	29	*36	*43	*58	*72	*143	*325
20	5	9	18	27	*36	*45	*54	*72	*89	*178	*405
22	6	11	22	*33	*44	*55	*66	*87	*109	*217	*494
26	8	16	31	*46	*62	*77	*92	*123	*154	*307	*696
30	11	21	*42	*62	*83	*103	*124	*165	*206	*411	*934
34	14	27	*54	*80	*107	*133	*160	*213	*266	*531	*1206
36	15	30	*60	*90	*120	*150	*179	*239	*299	*597	*1356

* Consider using a nitrogen truck for purges. See Table A6 for volume in SCF.

**Table A5
Volume (SCF) of Nitrogen Required To Form
the Minimum Required Slug Size in Pipeline
Indirect Method**

Pipe Size (inches)	*Pipe Length in Feet						
	2000	3500	5000	7500	10,000	20,000	50,000
12	263	321	368	433	486	653	985
16	430	527	605	712	802	1080	1632
18	553	677	777	915	1030	1387	2097
20	689	844	968	1139	1283	1728	2611
22	831	1017	1168	1375	1548	2085	3151
26	1162	1424	1633	1923	2165	2916	4406
30	1546	1895	2173	2561	2880	3880	5863
34	2204	2722	3137	3711	4189	5677	8630
36	2480	3067	3531	4179	4716	6391	9714

*Consider using bottles for smaller diameters and shorter lengths.

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Table A6
Volume (SCF) of Nitrogen Required to Fill Pipeline
Total Displacement Method

Pipe Size (inches)	Pipe Length in Feet										
	500	1000	2000	3000	4000	5000	6000	8000	10,000	20,000	50,000
6	*116	*231	*461	*691	*921	*1,151	*1,381	*1,840	*2,300	4,600	11,498
8	*202	*403	*805	*1,206	*1,608	*2,010	*2,412	*3,215	4,019	8,037	20,091
10	*320	*639	*1,277	*1,915	*2,552	*3,190	*3,828	5,104	6,379	12,758	31,893
12	*451	*902	*1,802	*2,703	*3,604	4,504	5,405	7,206	9,007	18,014	45,032
16	*699	*1,397	*2,792	4,188	5,584	6,979	8,375	11,166	13,957	27,914	69,782
18	*894	*1,786	*3,571	5,357	7,142	8,927	10,712	14,283	17,853	35,705	89,261
20	*1,112	*2,224	4,447	6,670	8,893	11,116	13,339	17,784	22,230	44,459	111,147
22	*1,357	*2,713	5,425	8,136	10,848	13,560	16,272	21,695	27,119	54,237	135,591
26	*1,915	*3,828	7,655	11,482	15,309	19,136	22,964	30,618	38,272	76,543	191,355
30	*2,568	5,134	10,268	15,401	20,534	25,668	30,801	41,068	51,334	102,668	256,668
34	*3,316	6,632	13,262	19,893	26,523	33,154	39,784	53,045	66,307	132,612	331,529
36	*3,729	7,457	14,912	22,368	29,823	37,279	44,734	59,645	74,557	149,112	372,779

* Consider using bottles for purges.



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NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Fully reviewed. Re-structured and re-formatted the standard for clarity, added/revised Sections 12, 13, and 14. Provided additional clarity on CGI requirements for purging operations, added/removed updated Operator Qualification covered tasks, and various editorial changes.

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ROUTING (COLLECTIBLE)
 [Redacted]
 (FORM 3466 & CO. PROPERTY DAMAGE REPORT)

ROUTING (NON-COLLECTIBLE)
 [Redacted]

If gas loss is on a transmission asset, please also route to [Redacted]

REPORTING OF GAS BLOWN TO ATMOSPHERE

Date Gas Blown	Location (Lay down yard, end points, or GPS coordinates)	City	District	Department

Reason For Gas Blown:
 [Redacted]

Account #	I/O#	USA Ticket #	SAP Plant Maintenance #	Cost Center	Collectible?
					No

Line Number	Outside Diameter (in)	Wall Thickness (in)	Pipeline Isolation Points (Stationing)		Total Miles Isolated
			From:	To:	

Company Damages

Is this project a result of company damage?

Blowdown Reduction Methods and Approach

Is this project bundled with other projects that resulted in a net blowdown reduction?
 Yes
 No

Project #1 IO	
Project #1 Percentage	
Project #2 IO	
Project #2 Percentage	

Project Bundling Details

[Redacted]

- Cross Compression
- CNG Capture (tanking)
- Draw Down Pressure
- Diverting to Other Local Lines
- Volume Reduction Via Stopple Fittings
- Thermal Oxidizers
- Other

How was the pipeline pressure reduced prior to blowdown?

If other, provide details: [Redacted]

Is the total volume released >500 MCF?

Provide explanation why:
 e.g. Safety or Reliability of service [Redacted]

Blowdown Estimation per Gas Std. 182.0032

Select automatic calculations or manual data entry for the following:

Operating pressure before pressure reduction (MOP if unknown):	0	PSIG
Gas consumed by equipment for blowdown reduction (will be provided by CNG team, otherwise 0):	0	MSCF
Pipeline pressure at the start of blowdown, after pressure reductions:	0	PSIG
Pipeline pressure at the end of blowdown (default is zero):	0	PSIG
Volume of Gas Saved Due to Pressure Reduction:	0.000	MSCF
Volume Emitted Due to Blowdowns or Purges:	0.000	MSCF

Prepared By:	Date:	Approved By:	Date:

Please route to [Redacted]

BLOWDOWN EMISSION REDUCTION PLAN

Planned Blowdown Date	Location (Lay down yard, end points, or GPS coordinates)	City	District	Department

Line Number	Outside Diameter (in)	Wall Thickness	Pipeline Isolation Points (Stationing)		Total Miles Isolated
			From:	To:	

How will the pipeline pressure be reduced prior to blowdown?

- Cross Compression
- CNG Capture (tanking)
- Draw Down Pressure
- Diverting to Other Local Lines
- Volume Reduction Via Stopple Fittings
- Thermal Oxidizers
- Other

If other, provide details: _____

Note: for ILI projects, please determine the cumulative volume for the entire project based upon the number of blowdowns at each launcher/receiver location.

- Provide verification:**
Check all Supporting Documentation
- Reserve or ZEVAC Quotes for Cross Compression
 - Communication Records of Gas Control Confirming availability of time for extended outage
 - RER Identifying Taps for Drawdown
 - Requests for CNG capture service
 - Other

If other, provide details: _____
Blowdown Estimation per Gas Std. 182.0032

Select automatic calculations or manual data entry for the following:

Automatic Calculations

- Estimated Operating pressure before pressure reduction (Enter MOP if unknown):
- Estimated Gas consumed by equipment for blowdown reduction (will be provided by CNG team, otherwise 0):
- Estimated Pipeline pressure at the start of blowdown, after pressure reductions:
- Estimated Pipeline pressure at the end of blowdown (default is zero):
- Projected Volume of Gas Saved Due to Pressure Reduction:
- Volume Planned to be Emitted Due to Blowdowns/Purges:

	PSIG
0	MCF
	PSIG
0	PSIG
	MCF
0.0	MCF

Prepared By: _____ Date: _____

2019 Decision Tree Pilot Study Statistics

239 Leaks were processed through the Decision Tree in 2019

- 15.5% of the leaks met the Decision Tree threshold from the Pilot Study
 - 69.2% were measured.
 - 18.5% of those were large leaks. This means that 2.1% of the total population of leaks are found to be large (i.e. ≥ 10 CFH).
 - 30.8% could not be measured (i.e. could not find the leak).

Quantities required to calculate an emission reduction:

1. Duration.
 - a. If the leak is not repaired, the duration of the leak is considered to be 365 days.
 - b. If the leak is repaired, the duration of the leak is considered to be the beginning of the year to the repair date.
2. Emission rate.
 - a. Average Rate (No Decision Tree Process):
When the decision tree is not applied (i.e. no prior information is known), an emission rate of 4.303 CFH is used. This value was the average rate for all random SoCalGas studies, per the 2019 Emission Factor Pilot Study report.
 - b. Decision Tree Rate (Decision Tree Process Applied):
When the decision tree is applied (i.e. above ground concentration measurements are provided), the emission rates are divided into specific categories:
 - i. Leaks where the emissions were measured, the flow rate measurement will be used for the emission rate.
 - ii. Leaks where the concentration measurements DID meet the decision tree thresholds and the actual emission rate was not measured were determined to have an average leak rate of 7.371.
 - iii. Leaks where the concentration measurements DID NOT meet the decision tree thresholds and the actual emission rate was not measured were determined to have an average leak rate of 2.267.

What was done for the emissions savings calculations in the Pilot Study area was:

1. Obtained all possible repair dates for the 239 leaks measured during the pilot study.
2. Durations were assigned to each leak according to the Duration criteria above.
3. The average leak rate was assigned to each leak according to the Average Rate criteria above.
4. Probabilistic emission factors were assigned to each leak according to the Decision Tree Rate criteria above to estimate the emissions associated with the Pilot Study area.
5. The leak durations were multiplied by the emission rates for each individual leak and the total rate was summed to compare the savings associated with applying the Decision Tree process vs not applying it.

Full Implementation

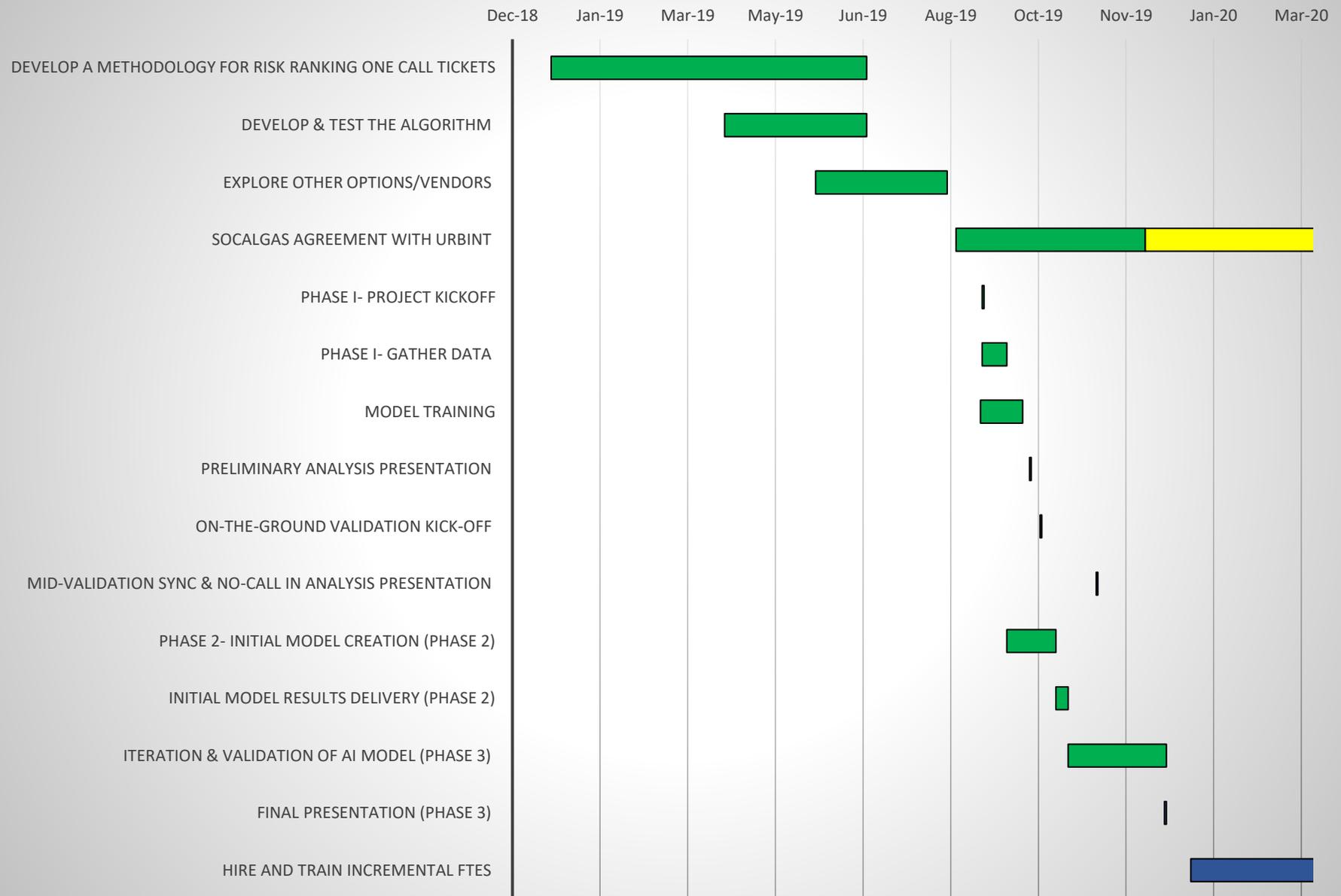
Based on the 2019 pilot study statistics, we can assume the following:

- 15.5% of the leaks will meet the Decision Tree threshold
 - 10% of those leaks expected to be in outlying areas. Therefore, no measurement will be taken, so an emission rate of 7.371 CFH will be used. These leaks will be prioritized for repair within a month of detection.
 - 90% of those leaks are to be within inlying areas.
 - Of those, 69.2% will be measured (i.e. have a flow rate measurement provided), and the measurement value will be used for the emission rate.
 - Of those leaks measured, 18.5% are to be large leaks. Those that are found to be greater than or equal to 6 CFH will be prioritized for repair within a month of detection.
 - Of those, 30.8% are not to be measured (i.e. could not find the leak), so an emission rate of 7.371 CFH will be used.
- 84.5% of the leaks will NOT meet the Decision Tree threshold, so the emission rate assigned to these leaks will be 2.267.

As an example, assuming a sample size of 5729:

- 4851 will NOT meet the Decision Tree threshold, so the emission factor assigned to these leaks will be 2.267 CFH.
- 878 will MEET the Decision Tree threshold
 - 88 leaks are expected to be in outlying areas (i.e. can't be measured), so an emission rate of 7.371 CFH will be used. These leaks will be prioritized for repair.
 - 790 leaks will be in inlying areas.
 - 547 leaks will be measured, and the measurement value will be used for the emission rate. A bootstrapped sample was created from the original study data to simulate the expected 547 leak measurements. Those that are found to be greater than or equal to 6 CFH will be prioritized.
 - 243 leaks will not be measured, so an emission rate of 7.371 CFH will be used.

Chapter 5 - Damage Prevention Algorithm & Proactive Intervention



Advanced Meter Analytics Business Case Estimation

O&M Cost Estimate Development

Annual Totals (Rounded in Thousands)			2020	2021	2022	2023	2024	Total
O&M Cost (Unloaded, no A&G, no AFUDC)	Business	Labor	\$140	\$186	\$186	\$186	\$186	\$884
		Non-Labor	\$0	\$0	\$0	\$0	\$0	\$0
	IT	Labor	\$70	\$93	\$93	\$93	\$93	\$442
		Non-Labor	\$0	\$0	\$0	\$0	\$0	\$0

ADVANCEDmeter

Leveraging Advanced Meter data to Enhance Operations and Benefit Customers

November 2019

How Analyzing Natural Gas Usage has Changed

Before **ADVANCED**meter

- » Customer Information Systems evaluated **monthly** meter reads
 - **70.8 Million reads per year**
- » Customer Billing Analysts analyzed consumption **based on Per Day Averages**
- » Customer Service Field technicians completed orders



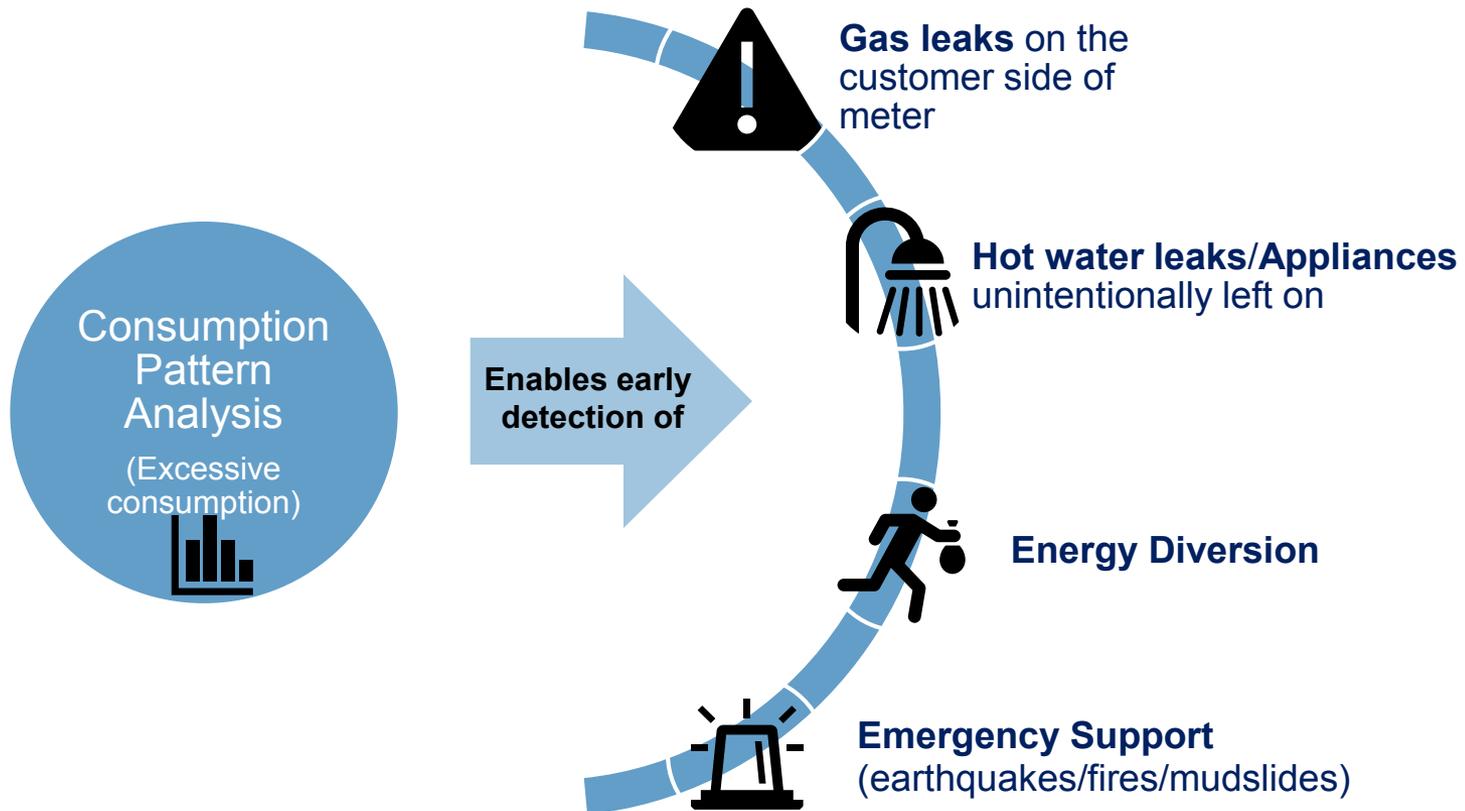
With **ADVANCED**meter

- » Advanced Meter algorithms evaluate **hourly** reads
 - **51.7 Billion reads per year**
- » Consumption pattern analysis enable **early detection of anomalies**
 - Abnormal usage
 - Earlier field investigation
 - Reduction of financial burden to customers



Leveraging Big Data to Create New Insights

➤ Use Cases based on *Consumption Pattern Analysis*



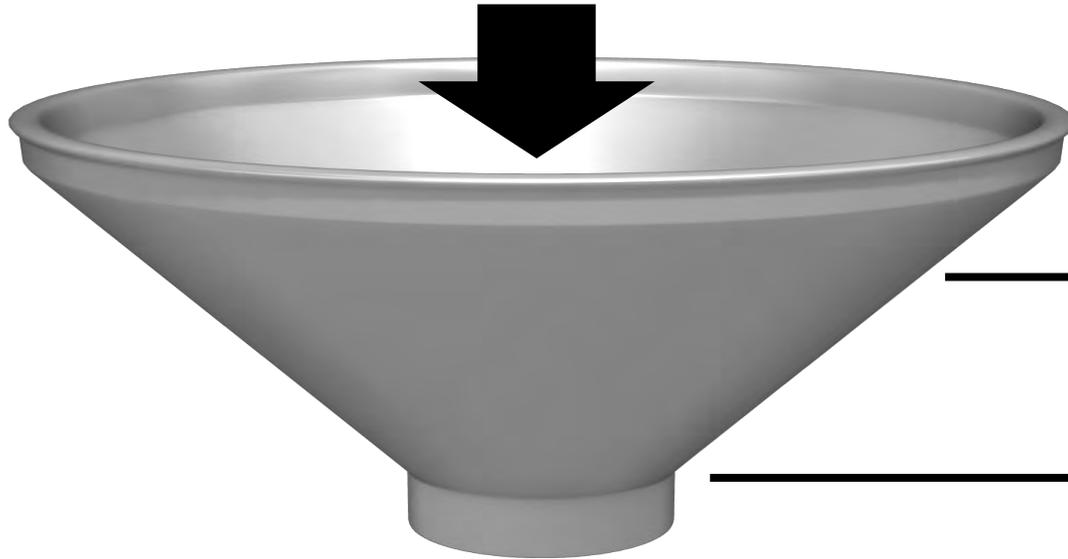
Consumption Pattern Analysis Foundation

Excessive Consumption

- **Consumption Pattern Analysis** is based on identification of **Excessive Consumption** anomalies
- **Excessive consumption anomalies** are reviewed and analyzed relative to meter size while keeping in mind consumption history and known appliances (i.e. pool heater, BBQ, etc.)
- Anomalies may be **caused by multiple reasons**:
 - Customer moving in or out
 - New appliances in use
 - Faulty, inoperative appliances
 - Newly advanced meter where hourly consumption patterns are not available
 - Diversion
 - Faulty Piping
 - Emergency Events

Analyzing Excessive Consumption

AMI hourly usage from 5.92M meters



Daily Volumes

Normal Consumption

- 5.91M meters

High Consumption

- 90K meters nominally
- 450K meters, heating season

Justified Consumption

- 88K meters nominally
- 448K meters, heating season

~3000

Monthly Results - October

Consumption returned to normal, 99%



95 - Gas Leaks

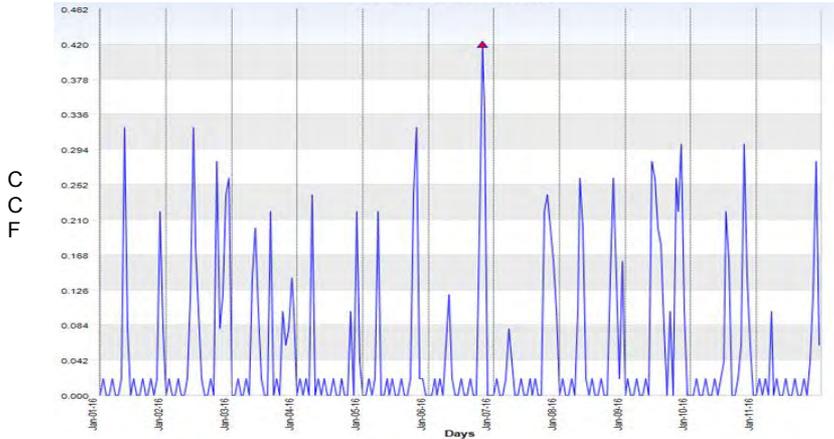
714 - Appliances Unintentionally Left On

193 - Meter shut-off for Excessive Registration

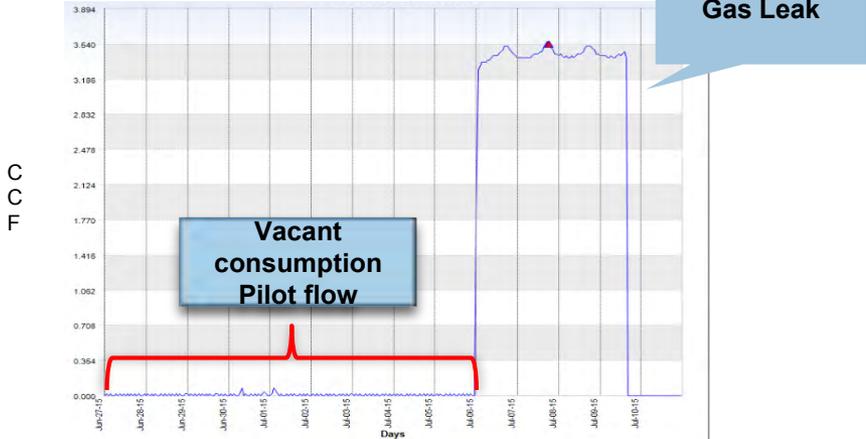
199 - Hot Water Leaks

Consumption Patterns

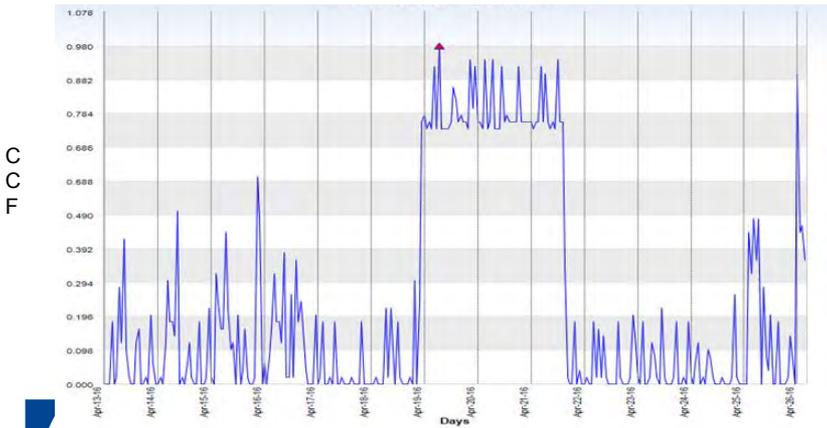
Normal Occupied Consumption



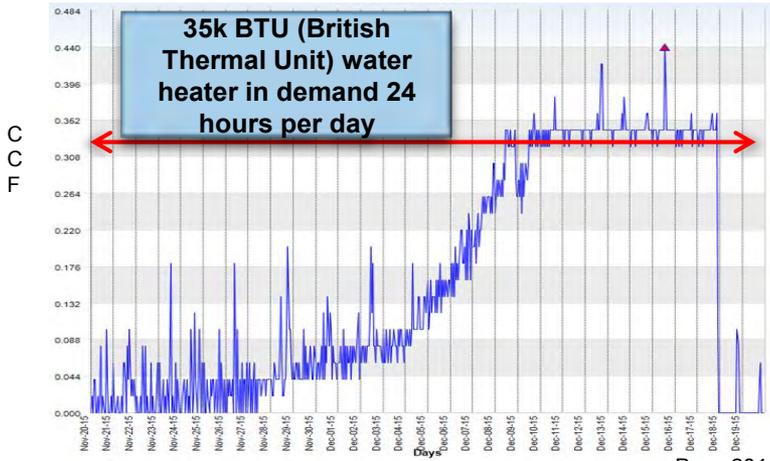
Potential Gas Leak



Appliance(BBQ) Unintentionally Left On

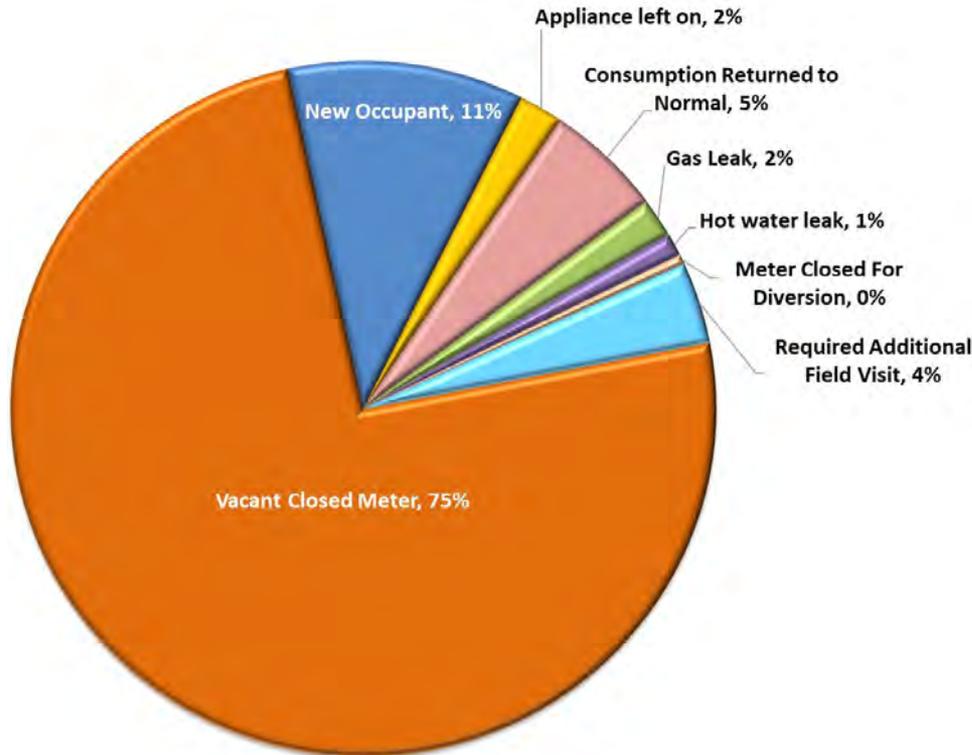


Hot Water Leak



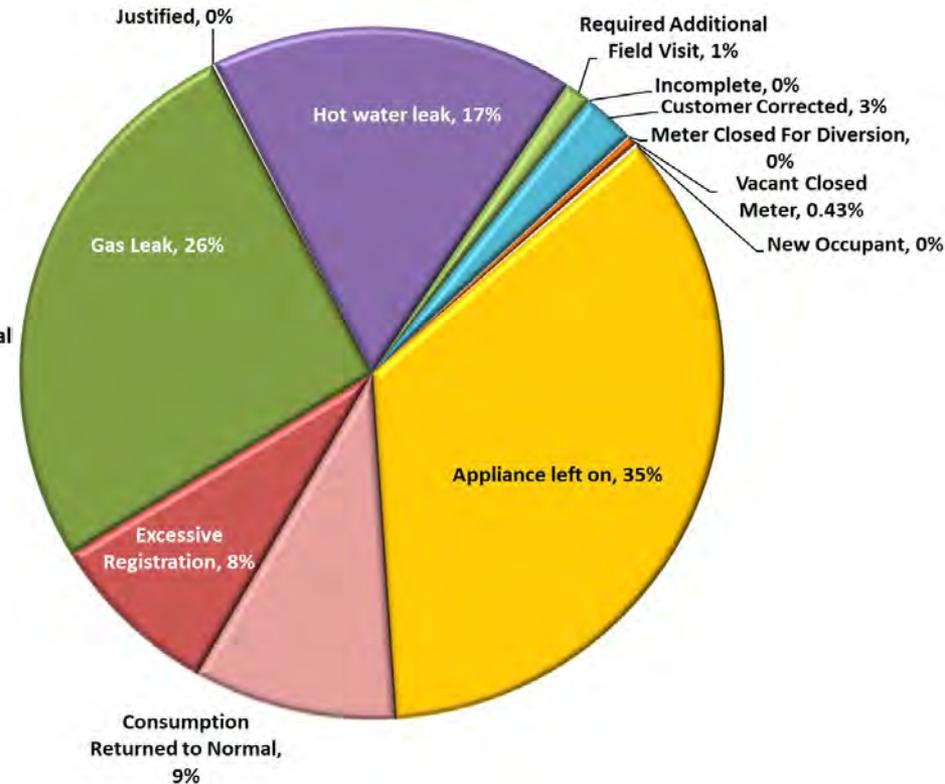
Premises Visited (YTD 2019)

Occupied



Total: 2,541

Vacant



Total: 2,115

NOTE: Occupied and Vacant categories are based on our Customer Information System reflecting a customer of record

Results: Abbreviated Details

October 2019

Completed Orders	Category	CS Field - Findings / Results	
4	A1 orders	<ul style="list-style-type: none"> (1) Houeline leak (1) Structure fire- Getty Fire (2) Pool heater in use 	
69	Gas Leak	<ul style="list-style-type: none"> (1) BBQ found disconnected and line valve open (3) BBQ left on not ignited (1) Bypassing service valve (3) Firepit left on not ignited (6) Fireplace left on not ignited (25) Houeline leak (1) leak at range connector 	<ul style="list-style-type: none"> (1) Leaking line valve for dryer (1) Leaking line valve for firepit (1) Loose meter ring on outlet side causing leak (1) Outdoor fireplace left on not ignited (25) Yard line leak
35	Hot Water Leak	<ul style="list-style-type: none"> (35) Suspected hot water leaks subsequently confirmed 	
55	Customer Corrected	<ul style="list-style-type: none"> (55) Field employee did not determine cause of high continuous consumption but consumption returned to normal (0) Consumption returned to normal prior to CSF employee arriving 	
83	Appliance left on	<ul style="list-style-type: none"> (44) BBQ left on (1) Circulating pump on water heater in use (1) Gas generator in use (3) Firepit left on (12) Fireplace left on (2) Grill left on 	<ul style="list-style-type: none"> (4) Heating appliance left on (1) Inop heating appliance (2) Inop water heater (2) Outdoor heating appliance left on (1) Outdoor oven left on (10) Pool heater in use
15	Incomplete	<ul style="list-style-type: none"> (15) Orders were incompleted and required a follow up order 	
11	Excessive registration	<ul style="list-style-type: none"> (11) Meter was closed due to excessive registration – meter is still off 	
160	Vacant Facilities	<ul style="list-style-type: none"> (160) Orders that were fielded at vacant facilities where high continuous consumption was stopped * Details available upon request 	
1	Meter Closed for Diversion	<ul style="list-style-type: none"> (1) Facilities that are off for non payment, bills had not been paid, and gas was turned back on by customer, and there was high continuous consumption for at least 24 straight hours. 	
12	New Occupant	<ul style="list-style-type: none"> (12) Vacant facilities where the determination of high consumption was due to a New Occupant 	
445	Total		

Proactive High Bill Investigations Results

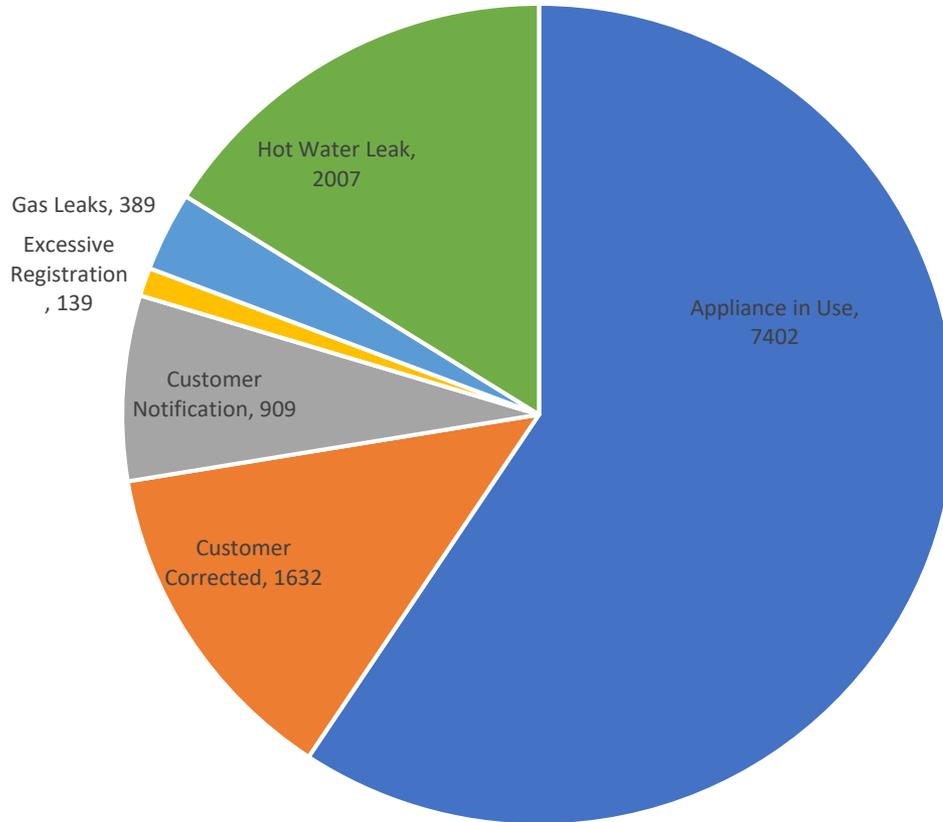
October 2019

- Customers are contacted by the HBI Desk when consumption consistent with a hot water leak or a BBQ unintentionally left on, is detected.
- When requested, the HBI Desk schedules a field visit by Customer Service Filed Operations.

Customer Notifications	Results Category	Proactive High Bill Investigation - Findings / Results	
182	Hot Water Leak	<ul style="list-style-type: none"> (43) Suspected hot water leaks subsequently confirmed by CSF Ops. (139) Hot water leaks confirmed by customers 	
45	Gas Leak	<p>43 Gas leaks confirmed by CSF Ops. 0 Gas leak confirmed by customers</p> <ul style="list-style-type: none"> (20) Yard line Leaks (20) House line Leaks (3) Fireplace (not ignited) 	<ul style="list-style-type: none"> (1) Leak at the meter (1) Pizza Oven (not ignited)
74	Customer Notification	<ul style="list-style-type: none"> (74) Customers were notified of suspected hot water leaks – Consumption remains consistent with a hot water leak 	
579	Appliance in use	<ul style="list-style-type: none"> (41) Appliance in use confirmed by CSF Ops. (52) Appliance in use confirmed by customers (486) Consumption consistent with prior usage or Returned to normal 	
364	Customer Corrected	<ul style="list-style-type: none"> (361) Consumption returned to normal after customer notification (3) Consumption returned to normal after CSF Ops. field visit was scheduled 	
10	Excessive registration	<ul style="list-style-type: none"> (10) Meter was closed due to excessive registration, FNP or Diversion – Consumption verified during Turn/On and Back/On orders 	
1,254	Total		

❖ Results verified by CSF Ops. may be included in the AMD R/V order results.

Proactive High Bill Investigation Results Year To Date - 2019



Findings/Results	Sum of YTD
Appliance in Use	7402
Confirmed by CSF Ops	300
Confirmed by Customer	2303
Consumption consistent with prior usage	4799
Customer Corrected	1632
Consumption returned to normal after CSF visit scheduled	13
Consumption returned to normal after customer notification	1619
Customer Notification	909
Suspected Hot Water Leaks	909
Excessive Registration	139
Meter was closed due to excessive registration,FNP or Diversion	139
Gas Leaks	389
House Line Leaks	197
Yard Line Leaks	159
Meter Leaks	5
Appliance Leaks	28
Hot Water Leak	2007
Confirmed by CSF Ops	338
Confirmed by Customer	1669
Grand Total	12,478

❖ Results verified by CSF Ops. may be included in the AMD R/V order results.

The Advanced Meter technology allows for **direct measurement of gas usage** which facilitates **transformational** process improvements in support of our business organizations and our customers.

THE POSSIBILITIES ARE ENDLESS...

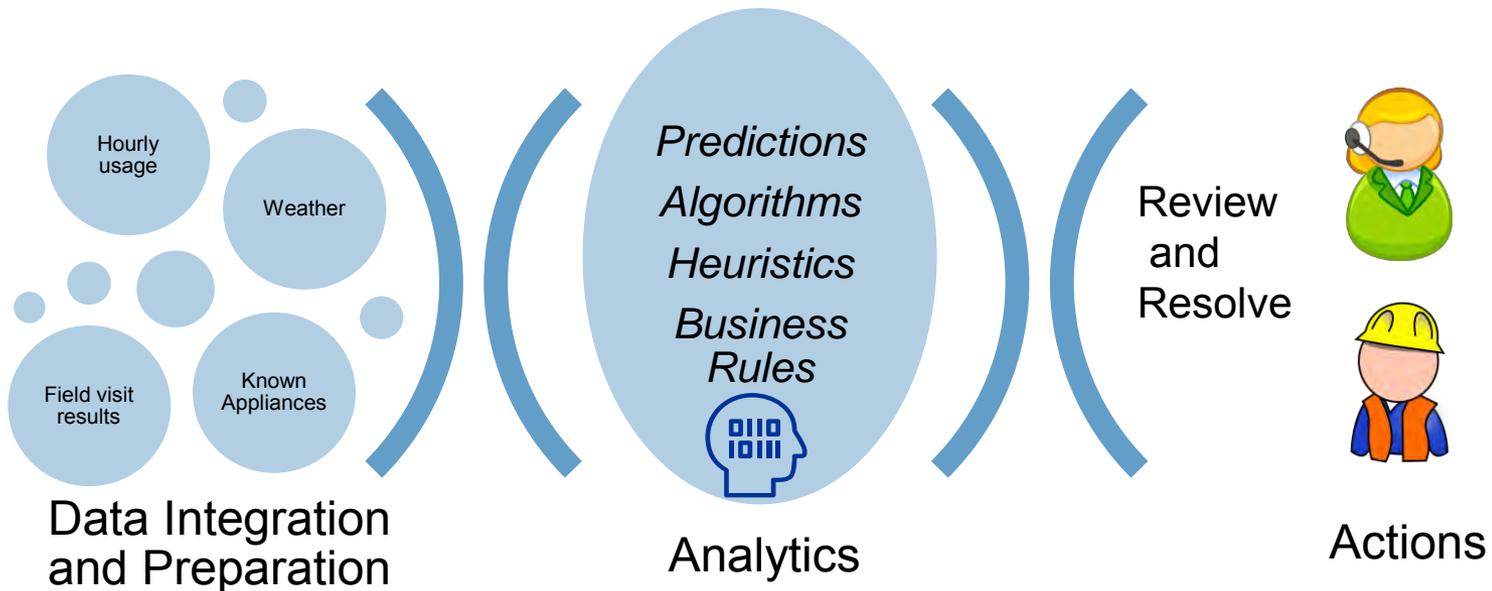
...on how we can use Advanced Meter data to better serve our customers!

APPENDIX

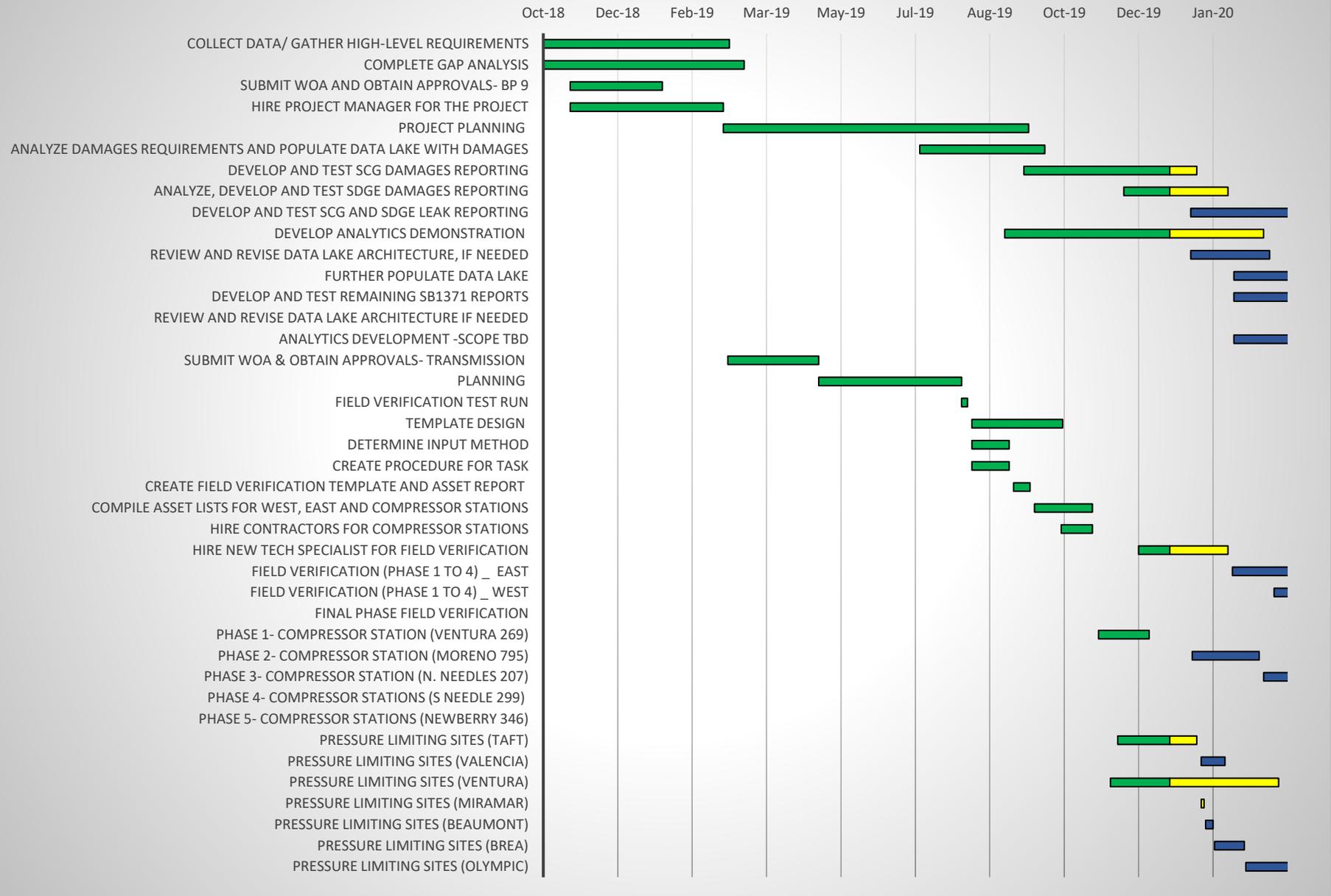
Advanced Meter Analytics Approach



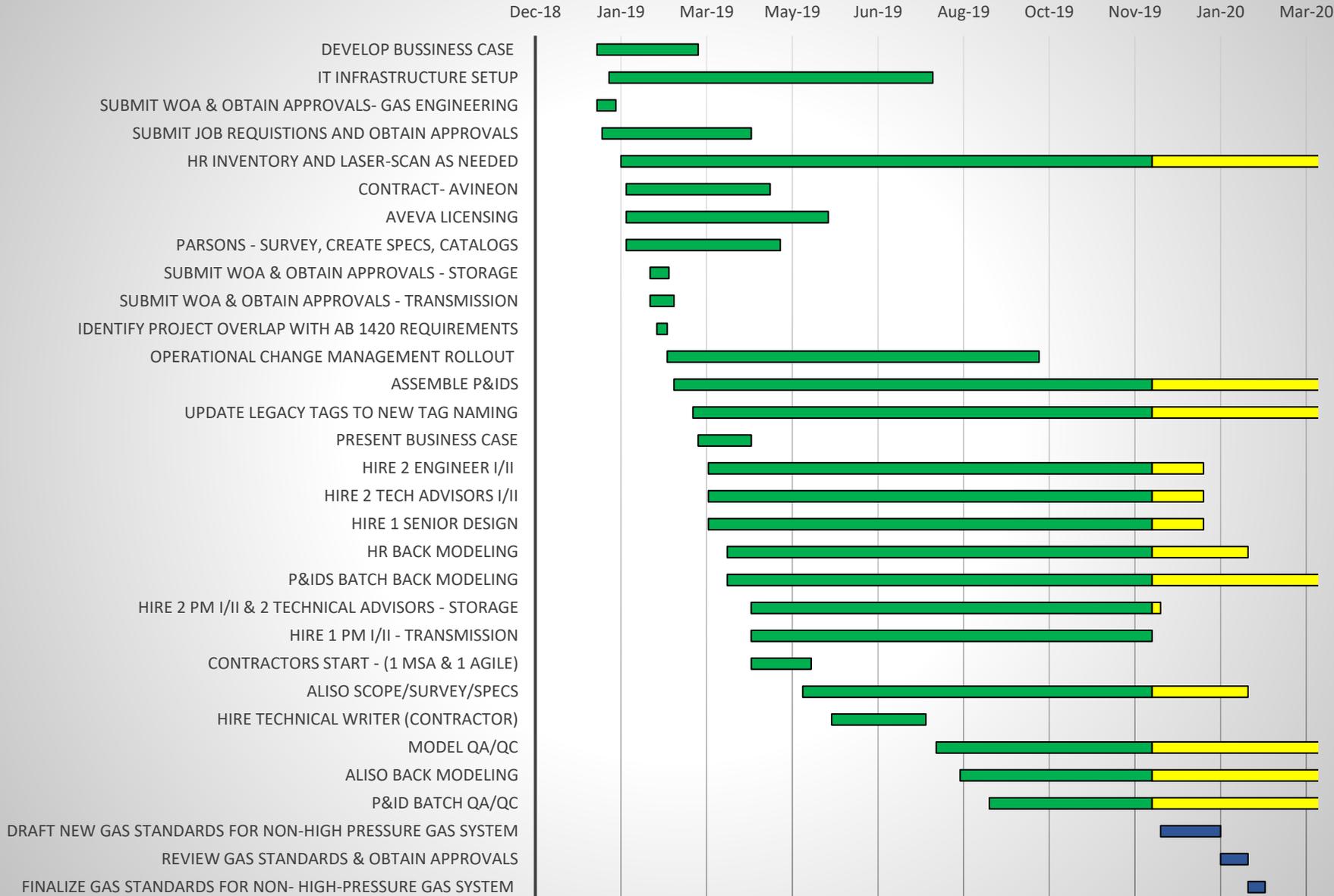
✓ Added capabilities from lessons learned and discovery.



Chapter 7 - Recordkeeping & Field Verification



Chapter 8 - Smart P&IDs and AVEVA 3D Modeling



Proposed Schedule for the 2021-2022 implementation:

ATTACHMENT K

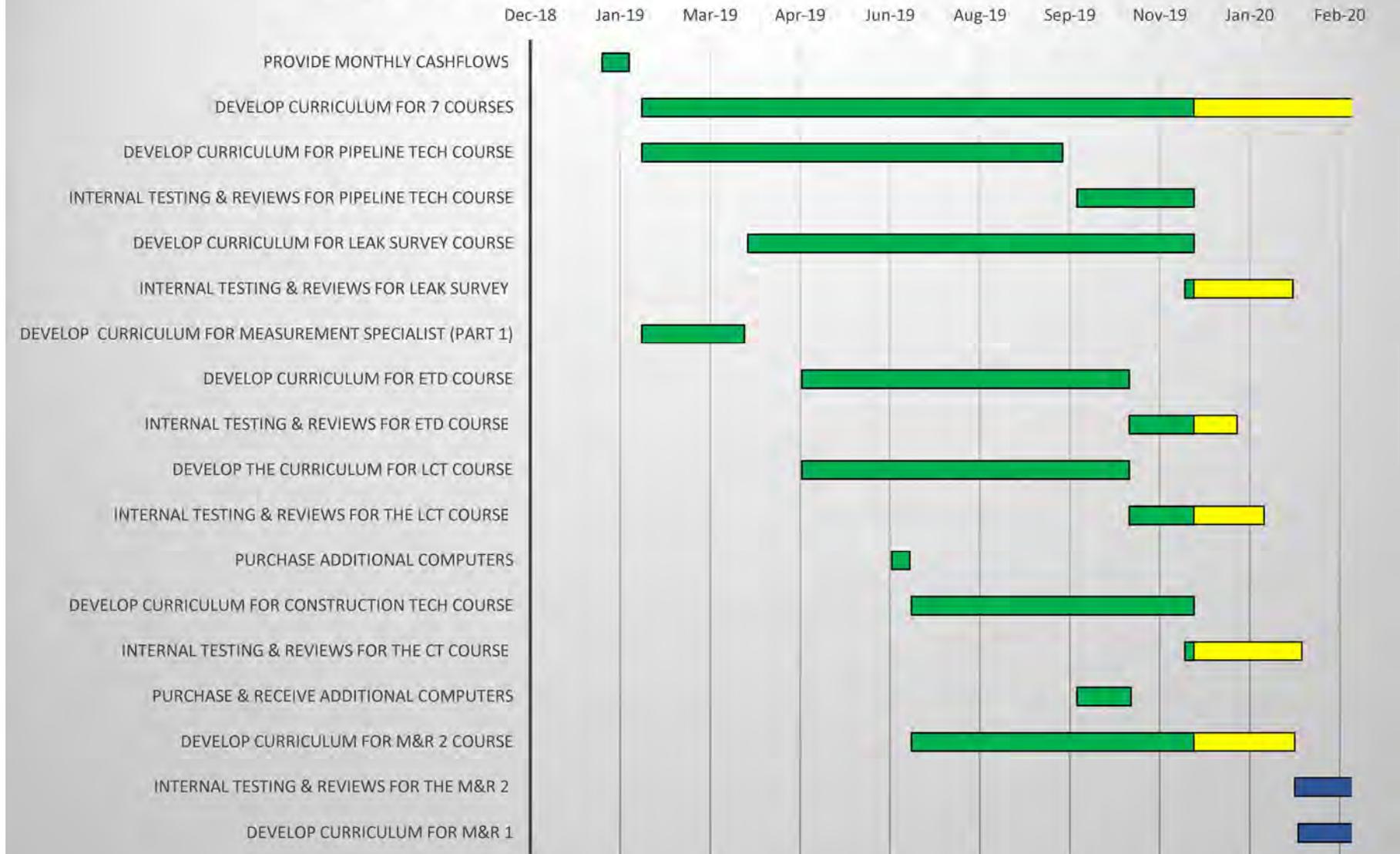
Facilities	Cost	Timeline
3D modeling total	\$ 2,100,000	
Facility 1	\$ 600,000	2021 QTR 1 - 3
Facility 2	\$ 600,000	2021 QTR 3 - 2022 QTR 1
Facility 3	\$ 300,000	2022 QTR 2
Facility 4	\$ 300,000	2022 QTR 2 - 3
Facility 5	\$ 300,000	2022 QTR 3 - 4
800 PIDs	\$ 800,000	2021 - 2022 (breakdown in chart below)

AVEVA 3D Modeling	2021				2022			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Facility 1								
Facility 2								
Facility 3								
Facility 4								
Facility 5								

PID Work (~800)	2021				2022			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Mechanical/Process								
Facility 1 (SDG&E)								
Facility 2 (SDG&E)								
Facility 1								
Facility 2								
Facility 3								
Facility 4								
Facility 5								
Misc. PIDs								

PID Work (~690)	2021				2022			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Instrument and Controls								
Facility 1								
Facility 2								
Facility 3								
Facility 4								
Facility 5								
Facility 6								
Facility 7								
Facility 8								

Chapter 9 - Performance Focused Training Program



SB 1371 BP13 12/3/2019 Status Report



Background

BP13 mandates utilities use Performance-Focused Training Programs to instruct workers, including contractors, on how to perform Best Practices, efficiently and safely.

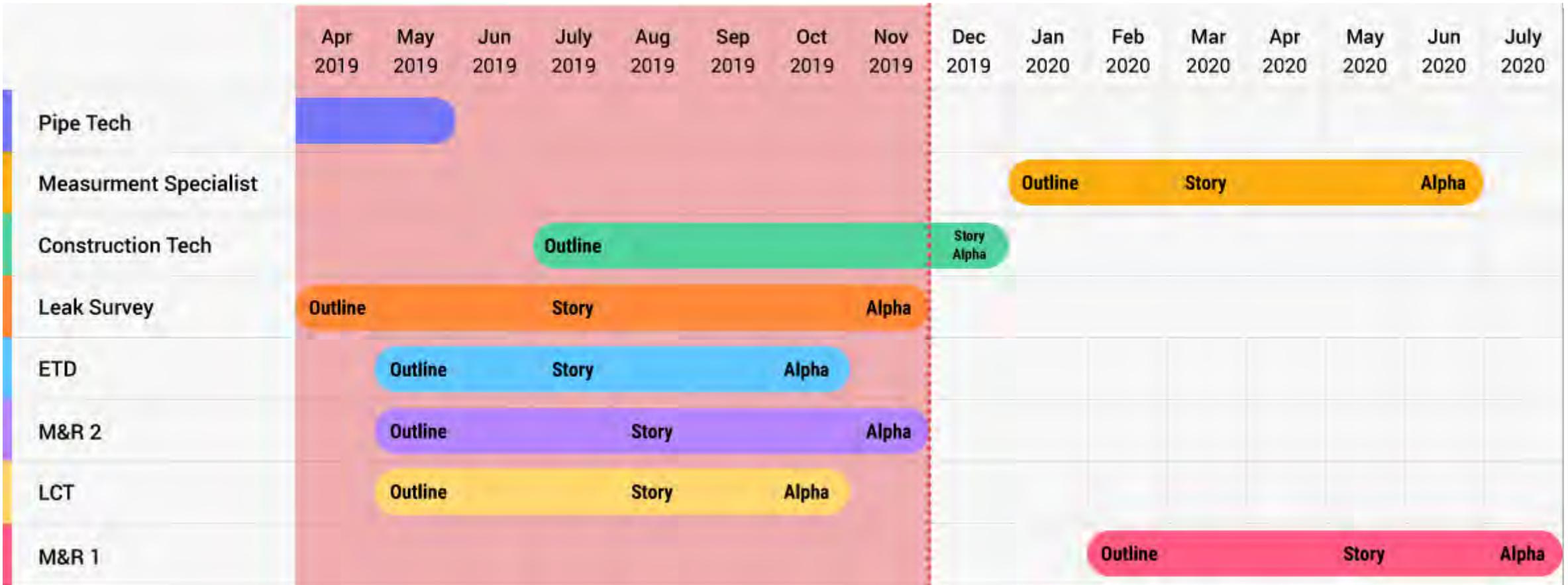
As a component to “performance-focused” (i.e.: criterion referenced) training we are developing self-paced, modular, interactive eLearning that will complement hands-on activities.

Summary

- We are on track with the project regarding schedule and budget, and things are going well
- We have completed development for the following courses: Pipe Tech, Leak Survey, ETD, M&R 2 and LCT and are on track to complete Construction Tech by the end of the year.
- Content is being developed with a modular approach which better facilitates sharing across multiple job roles

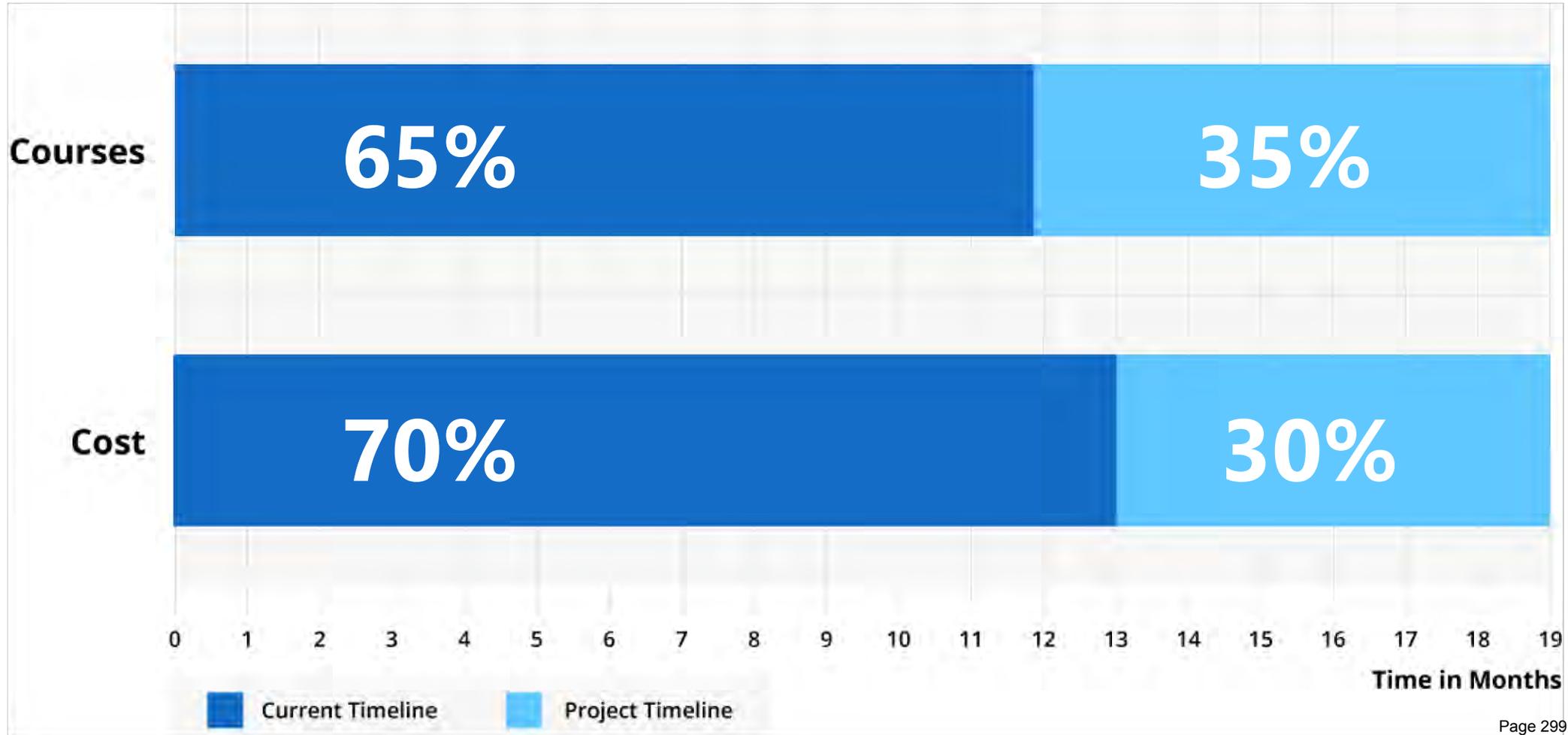


BP13 Project Timeline



Status: We are currently on schedule

SoCalGas BP13 Project Timeline

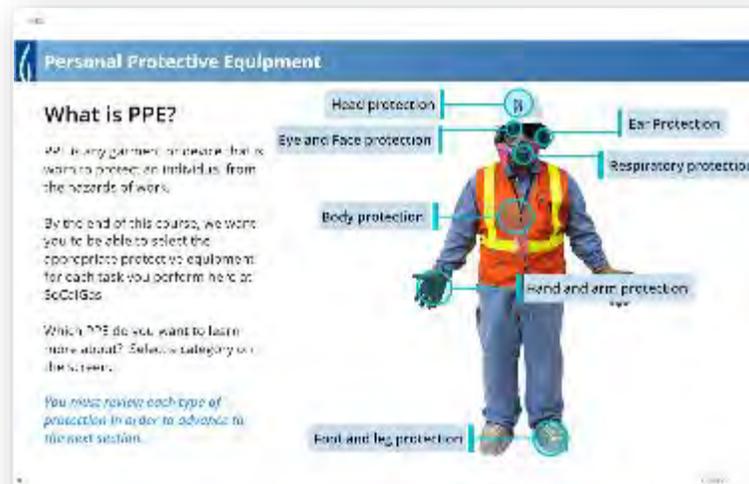


Online Training Samples



Fundamental Safety Practices

<https://360.articulate.com/review/content/a8261633-58e8-4b2c-a889-37da35ebc8da/review>



Personal Protective Equipment (PPE)

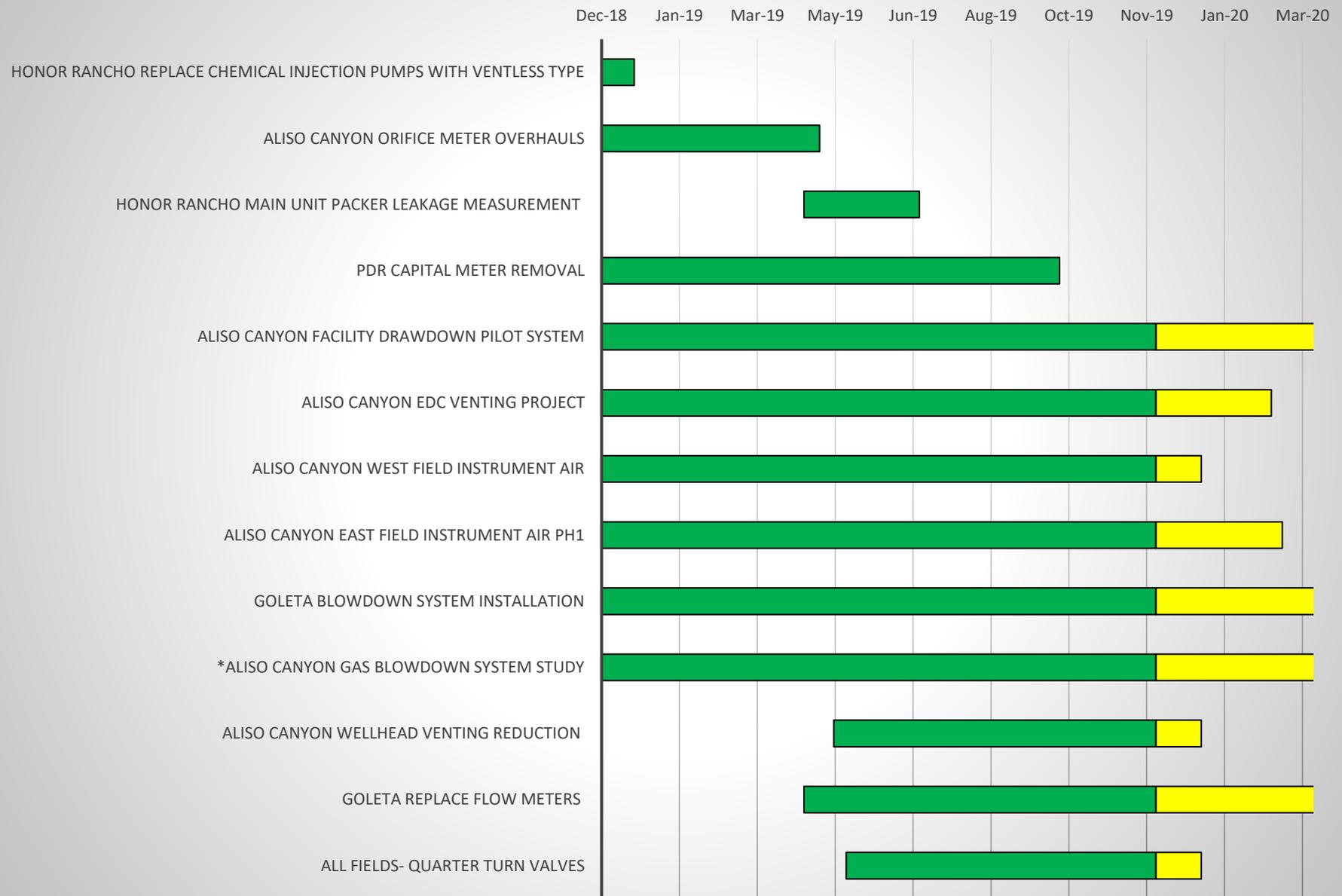
<https://360.articulate.com/review/content/488ba441-2fa0-4df2-a8c9-df6135b4de5d/review>



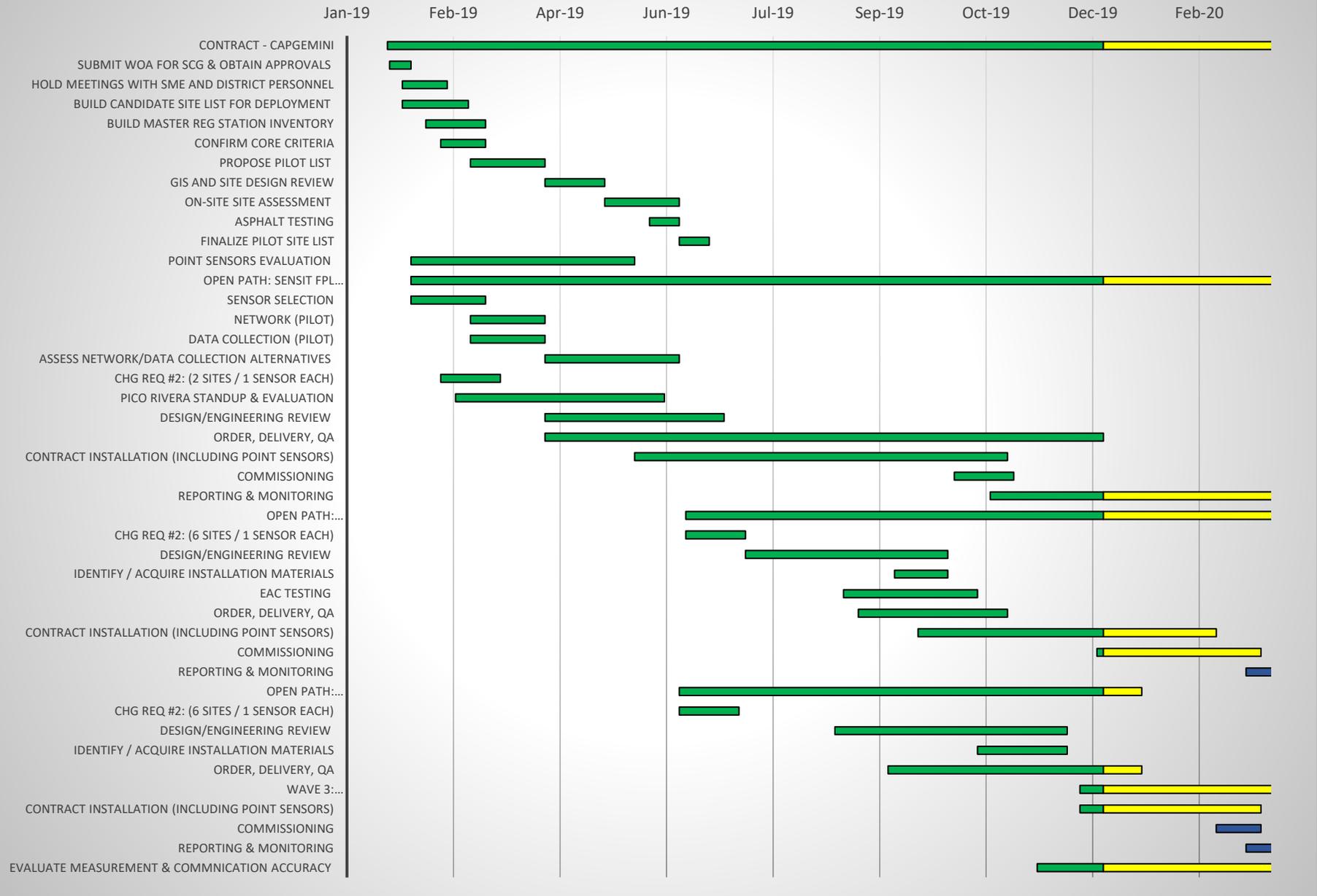
Hydraulic Torque Wrench Calibrator

<https://360.articulate.com/review/content/b55a823f-f1b3-40c5-a638-af3173b7b7a5/review>

Chapter 11 - Storage Projects



Chapter 12 - Stationary Methane Detectors



SB1371: Leak Abatement

*Best Practice 18:
Methane Sensor Pilot Overview*



BP18 Background

The July 2018 Amended Leak Abatement Compliance plan included a best practice focused on deploying stationary methane detectors at company facilities. The initial project phase will focus on a detection pilot.

Description	Utilities shall utilize stationary methane detectors for early detection of leaks as locations such as compressor stations, terminals, gas storage facilities, city gates, and M&R regulator stations installed above ground with pressure above 300 psig inlet pressure that feed a distribution supply line.
Proposal	Two options were presented in the compliance plan: <ol style="list-style-type: none">1. Execute a two-year pilot of 10-20 sensors to assess O&M costs, accuracy, and the impact of false alarms. Collected measurements would be compared against data gathered by on-site leak surveys to evaluate anticipated emission reductions in comparison to incremental costs.2. Move forward with Year 1 deployment at 47 sites across the facility types listed. Additional deployments will proposed in a future compliance plan for a total 236 sensors over a three-year period.
Decision	Option #1: Plan and execute a methane detection technology pilot focused on emission reduction.

Objective and Approach

Execute a structured technology pilot to assess the viability of available methane detection solutions and their effectiveness in emissions reduction

Objective

Determine whether a proven technology reliably measures and communicates methane levels at above ground M&R Regulator stations in a manner that enables leak detection and emission reduction.

Approach



- Install detection technologies at **10 above ground M&R Regulator stations** with inlet pressure above 300 psig
- Deploy Infrared Optical point sensors and Tunable Diode Laser Absorption Spectroscopy (TDLAS) open path sensors
- Monitor emissions from normal operations
- Perform controlled emission testing at a subset of sites
- To minimize costs and facilitate comparison, **multiple detection technologies may be installed at select sites**. If deemed necessary, multiple instances of a given solution can be installed at a individual site to assess detection accuracy (e.g. point sensors at multiple locations at a site)
- Generate a summary report at the conclusion of the monitoring period. The report will detail pilot results by technology and recommend an appropriate course of action moving forward

Objective and Approach

Each site will include two point sensors and one of the three types of open path sensors

Point Sensor



3M

- Model: IR-700-CH
- Number per site: Two
- Site Distribution: All sites

Open Path 1



Sensit

- Model: Gas Trac FPL
- Number per site: One
- Site Distribution: Two sites

Open Path 2



Boreal

- Model: Gas Finder3-OP
- Number per site: One
- Site Distribution: Six sites

Open Path 3



Envea

- Model: LAS 300 OP-2
- Number per site: One
- Site Distribution: Two sites

Recommended Technology

3M IR-700-CH



3M Gas & Flame Detection (formerly Detcon)	
IR-700-CH (formerly CX-IR-RB)	
Type	Non-dispersive infrared optical (NDIR)
Gases detected	Combustible hydrocarbon
# Programmable alarms	2
Outputs	4-20 mA, RS-485 Modbus
Measurement Range	0-100% LEL
Accuracy / Repeatability	±3% 0-25,000ppm; ±5% 25,000-50,000 ppm Test results show reliable detection at 1000 ppm
Sensor Life	3-5 years typical
Sensor Replaceable	Plug-in field replaceable (including under power)
Response Time	T50 < 6 seconds T90 < 10 seconds
Safety	Class 1, Division 1
Power	Rechargeable Lithium ion
Run Time before recharge	With 4-20mA output - 3 months / With Relay Output - 6 months
Power Inputs	Battery, 7-30 VDC, 110/220 VAC 50-60 Hz
Display	4-character scrolling alphanumeric LED

Recommended Technology

Sensit Gas Trac FPL



SENSIT Technologies	
Gas Trac FPL	
Type	Open Path, Tunable Diode Laser Absorption Spectroscopy (TDLAS)
Configuration	Single or Dual path assembly
Gases detected	Tunable to Methane
Path Length	1-30 meters
Outputs	RS-485 Modbus
Measurement Range	0-10,000ppm-m
Accuracy / Repeatability	2ppm-m
Sensor Replaceable	Yes
Response Time	Less than 0.1 seconds
Power	Built in Rechargeable Battery maintained by solar panel.
Run Time before recharge	4 days without recharge via solar panel
Power Inputs	Integrated solar panel
Display	Yes

Recommended Technology

Boreal GasFinder3-OP



Boreal Gas Trac FPL	
Type	Open Path, Tunable Diode Laser Absorption Spectroscopy (TDLAS)
Configuration	Single or Dual path assembly
Gases detected	Tunable to Methane
Path Length	0.5m to 750m
Outputs	RS-485 Modbus
Measurement Range	0.2 – 2500 ppm
Accuracy / Repeatability	Within 2% of reading
Sensor Replaceable	Yes
Response Time	1 second
Safety	To be confirmed
Power	Requires 20W continuous
Display	Touchscreen display optional

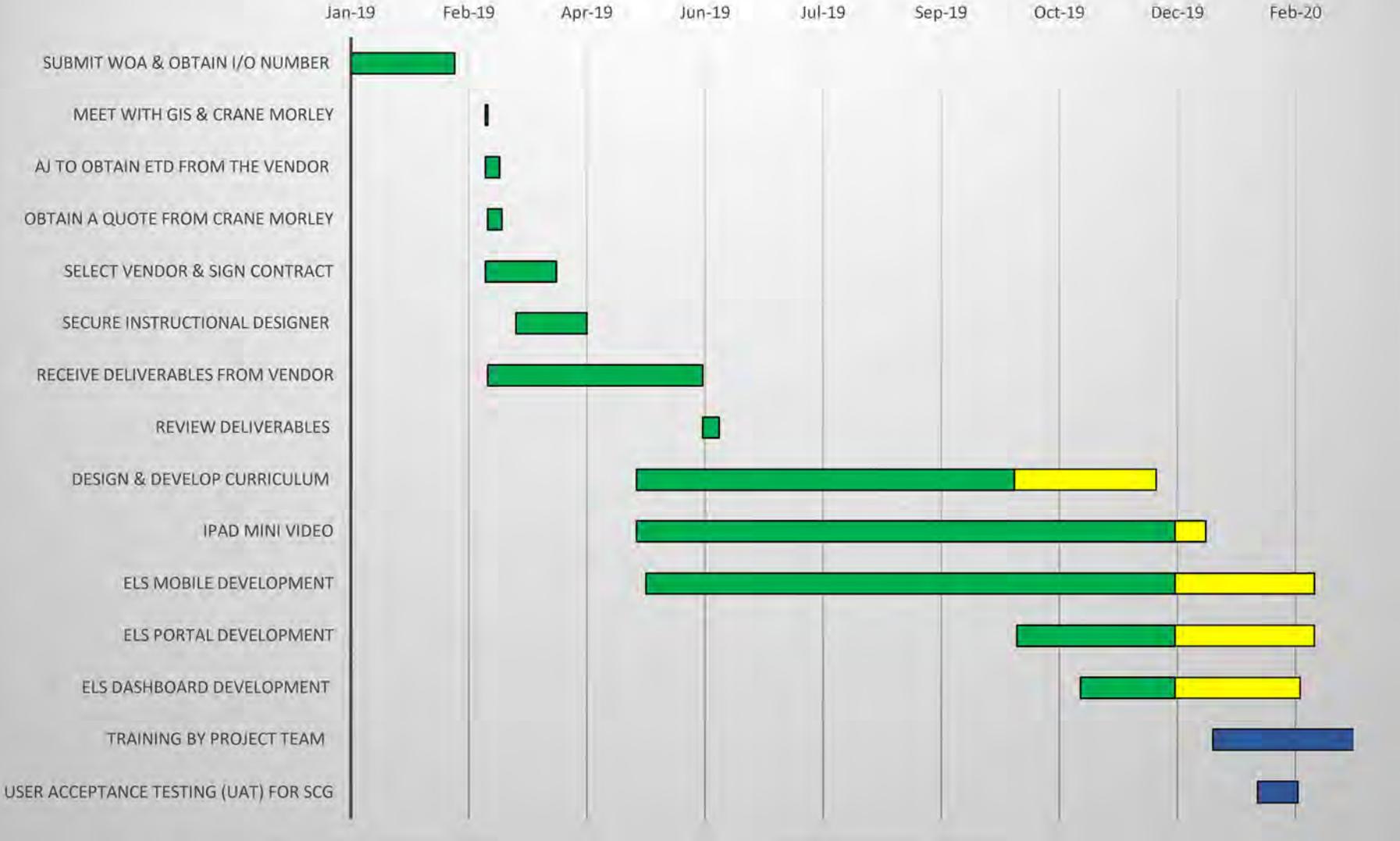
Recommended Technology

Envea LAS 300 OP



Envea Gas Trac FPL	
Type	Open Path, Tunable Diode Laser Absorption Spectroscopy (TDLAS)
Configuration	Single or Dual path assembly
Gases detected	Tunable to Methane
Path Length	0.1 to 750m depending on laser head
Outputs	4-20 mA, RS-485 Modbus
Measurement Range	0.5 – 750ppm depending on laser head
Accuracy / Repeatability	$\leq \pm 2$ % of full scale
Sensor Replaceable	Yes
Response Time	1 second
Safety	Unclassified
Power	Requires 15W
Display	800 x 600 projected capacitive touchscreen

Chapter 13 - Electronic Leak Survey (ELS) Training



Electronic Leak Survey/Patrol Project

December 5, 2019

- Completed Device Selection, Vendor Selection, Requirements Gathering and System Design activities.
- Finished Development of major components and conducted initial round of system integration testing activities to validate integration paths and end to end functionality.
- Project team conducted field demos of the mobile application as well as portal application to get user feedback. Team is currently testing the latest release of mobile application to make sure that the requirements are met.
- Team is working on Hardware & Software acquisition – mobile devices (iPad), accessories & support software
- User Acceptance Testing will be conducted towards the end of January in preparation of the Pilot to be conducted in Q2 2020.
- Change Management team is in place. It has started engaging stakeholders and plans to provide information through DigiBoards at District locations, GasLines article and District visits.

Gas Mapping LiDAR™

A Service for the Oil & Gas Industry

Service Features

- Monitors methane leaks throughout the entire natural gas value chain
- Detects leaks 20-100 times more sensitively than airborne IR camera solutions
- Locates leaks to equipment level
- Quantifies leak rates (flux) with industry-leading accuracy
- Maintains performance even with interference from off-site emissions
- Provides real-time alerts for dangerous leaks
- Provides verifiable, time-stamped, and geo-registered record of monitoring for simple auditing
- Provides “answer key” identifying which sites to visit to expedite regulatory monitoring
- Minimizes liability of costly accidents

Bridger Photonics’ (Bridger’s) Gas Mapping LiDAR™ (GML) service makes finding and prioritizing leaks simple. GML uncovers and quantifies natural gas (methane) leaks and physical changes in oil & gas infrastructure including well pad fields, processing facilities, and underground pipeline right-of-ways.

GML uses proprietary laser-based remote sensing technology from an airborne platform to provide 3D LiDAR and sensitive methane concentration maps overlaid on aerial or satellite photography (see example below). GML’s proprietary analytics provide leak source locations (GPS coordinates), leak rates (flux), real-time alerts for dangerous leaks, and other information. This information allows oil & gas operators to expedite regulatory compliance monitoring, accurately quantify their methane reductions, and minimize liability of costly accidents.

GML offers industry-leading performance and simplicity. GML’s measurement sensitivity is 20 to 100 times more sensitive than airborne IR camera solutions and more than 1,000 times better than the lower explosive limit. GML can distinguish between on-site leaks and interference emissions from other sites. All GML data is time-stamped, geo-registered and can flow seamlessly into customer GIS software (ArcGIS, QGIS, Google Earth, etc.) for simple record-keeping, analysis, and auditing.



Emitter Information:
 Detection Number: 37
 Date/Time: 06/21/2018 4:51:58 PM
 Location: 40.5956485, -105.1393781
 Max Concentration (ppm-m): 3052

Flux Information:
 Detection Number: 37
 Date/Time (UTC): 06/21/2018 4:51:58 PM
 Mean Flux (scfh): 20.8±5
 Background Flux: (scfh) 2.0
 Windspeed (mph): 2.5
 Plume Height (ft): 7



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Gas Mapping LiDAR™

A Service for the Oil & Gas Industry



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Description

Applications

GML has the flexibility and sensitivity to monitor the entire natural gas value chain from “well head to meter”. GML is well suited to large-area projects such as full-field well pad monitoring, long-range linear projects like pipeline right-of-ways, and isolated projects like individual facilities or well pads. Bridger uses an airborne platform (fixed-wing airplane, helicopter, or drone) for data acquisition that is best suited to the customer project, sensitivity, and coverage area requirements.

Customers can simply provide the site location/area, minimum desired leak rate sensitivity, date range, and other project details, and Bridger delivers the specified data. This data provides customers with an “answer key” identifying which sites they need to visit, which reduces customers’ “windshield time” liability.

Because GML locates leaks to the equipment level, each visit is more efficient, and customers save time in repair. Because GML accurately quantifies the leak rates, customers can prioritize repair efforts or simply monitor small leaks over time.

Proven Capabilities

Bridger developed GML with support from the US DOE’s Advanced Research Projects Agency – Energy (ARPA-E) program. As part of ARPA-E, Bridger conducted single-blind testing of GML at the Methane Emissions Test and Evaluation Center (METEC) facility in Colorado.

For Round 1 testing in 2017, GML detected all 17 issued leaks (plus one null) across three well pads and located – in three dimensions – all issued leaks to within a 3-foot (1.28-meter) radius of the source (see Figure 1(left) for example results from Well Pad #1 localization). This makes Gas Mapping LiDAR™ ideal for quickly identifying the equipment that is leaking for efficient repair or regulatory monitoring.

GML also quantified all issued leak rates to within 50% of the METEC uncertainty range (see Figure 1(right) for GML quantification results for all issued leaks). This capability makes GML ideal for prioritizing repairs and quantifying reductions.

Round 1 testing was intentionally performed under ideal scenarios (e.g. mild and accurately known wind fields, static sensor position, isolated leaks, <150’ range). However, the results establish that GML’s analytics are fundamentally sound. Contact us for performance expectations under other measurement scenarios.

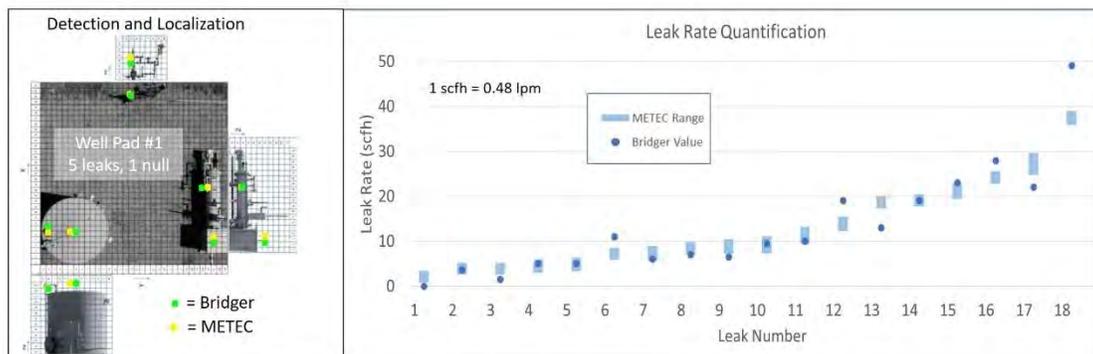


Figure 1. Left: Round 1 localization results for Well Pad #1 showing actual locations (yellow) and Bridger measured locations (green). Right: Round 1 quantification results showing METEC emission uncertainty range (light blue bars) and Bridger emission measurements (dark blue dots) for a null and 17 leaks. This chart shows the leak rates in ascending order, not the order of leak issuance. Page 315 of 495

Gas Mapping LiDAR™

A Service for the Oil & Gas Industry



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Bozeman, MT 59715

Specifications

Parameter	Typical Performance
Chemical species	Methane (CH ₄) [*]
Lower concentration limit	2-100 ppm-m [†]
Upper concentration limit	50,000 ppm-m
Lower leak rate limit	2-100 scfh (1-50 lpm) [†]
Upper leak rate limit	None unless concentration limit reached
Geo-registration accuracy	2 m x 2 m
Aerial photography resolution	Up to 8 megapixels
Min gas image pixel density	0.25 m ⁻²

Specifications are subject to change without notice

^{*} Contact us for other species.

[†] Bridger adjusts flight platform and parameters to meet customers' lower detection limit requirements.

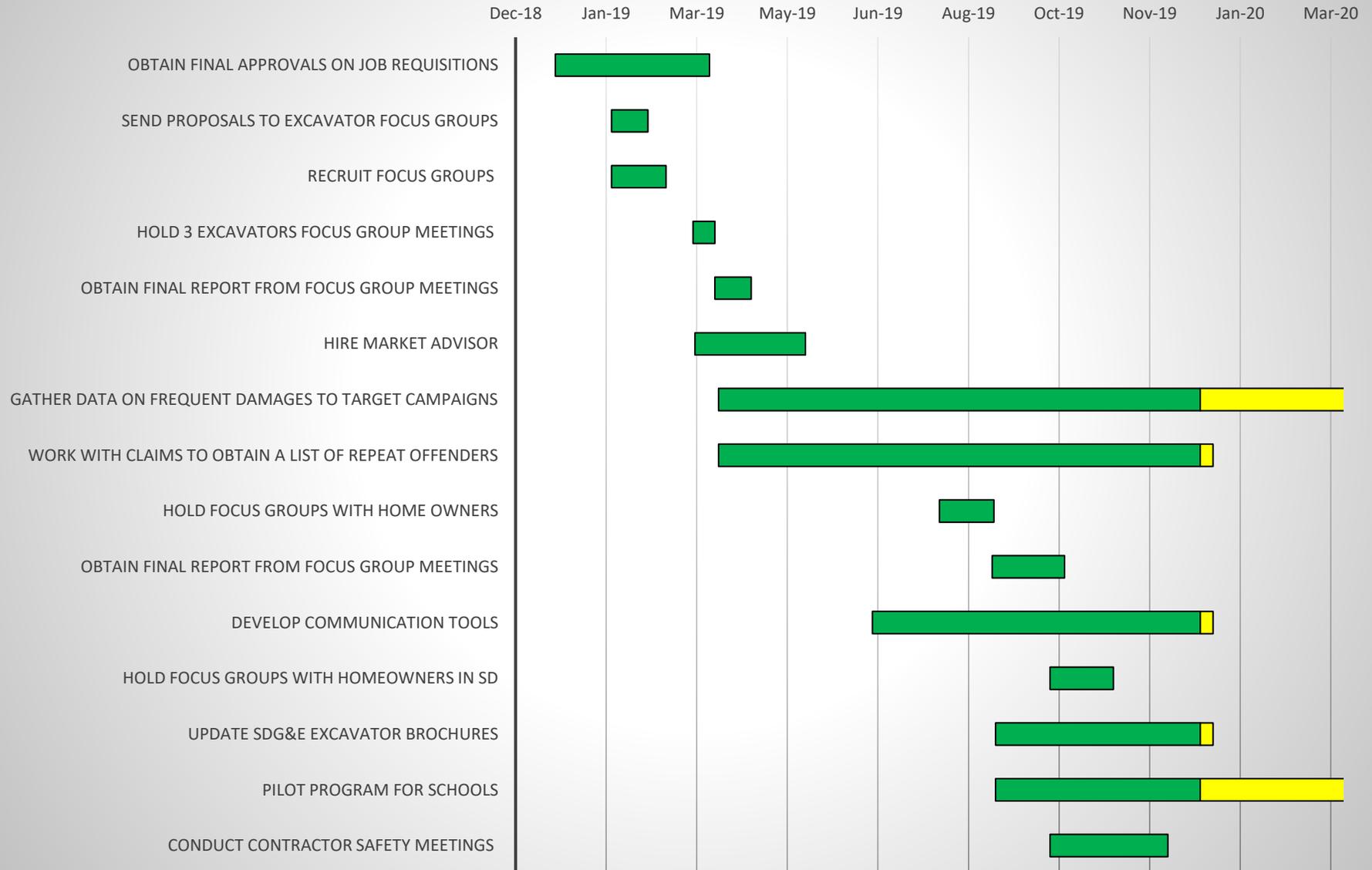
BP Aerial LIDAR Leak Detection

Factor	Assumptions & Calculations	Notes
Miles of Main per Sq. Mile	23.17	Based on Lake Forest evaluation
Number of Services per Sq. Mile	2,053	Based on Lake Forest evaluation
Miles of Main	19377	Based on Ch 14
Adjusted Total Miles of Main	29065.5	Assume 1.5 factor for overlap with embedded NSOTA and Bus. Dist.
Service Factor	1.694244604	Factor used to add Service Mileage (471/278 based on Lake Forest)
Calculated total miles of Main and Service	32,829	Miles of Main and Service
Number of Flight Areas	118.09	
Price per area	\$ 35,040	
Cost per year for Aerial Survey Services	\$ 4,137,919	
Emission abatement per Large leak repair	64.56996	Mscf
Emission abatement per Regular leak repair	9.92946	Mscf
Number of Large System Leaks Detected and Repaired per area	2	
Number of Regular system leaks detected and repaired per area	3	
Emission abatement from large system leak repairs per area	129.13992	Mscf
Emission abatement from regular system leak repairs per area	29.78838	Mscf
Total System Emissions abatement per year	18,768	Mscf
Number of Large Customer Leaks Detected and Repaired per area	7	
Number of Regular Customer leaks detected and repaired per area	4	
Emission abatement from Large Customer leak repairs per area	451.98972	Mscf
Emission abatement from Regular Customer leak repairs per area	39.71784	Mscf
Total Customer Emissions abatement per year	58,066	Mscf
Total Number of leaks on the system found and mitigated	590	
Total Number of leaks on the Customer system found and mitigated	1,299	

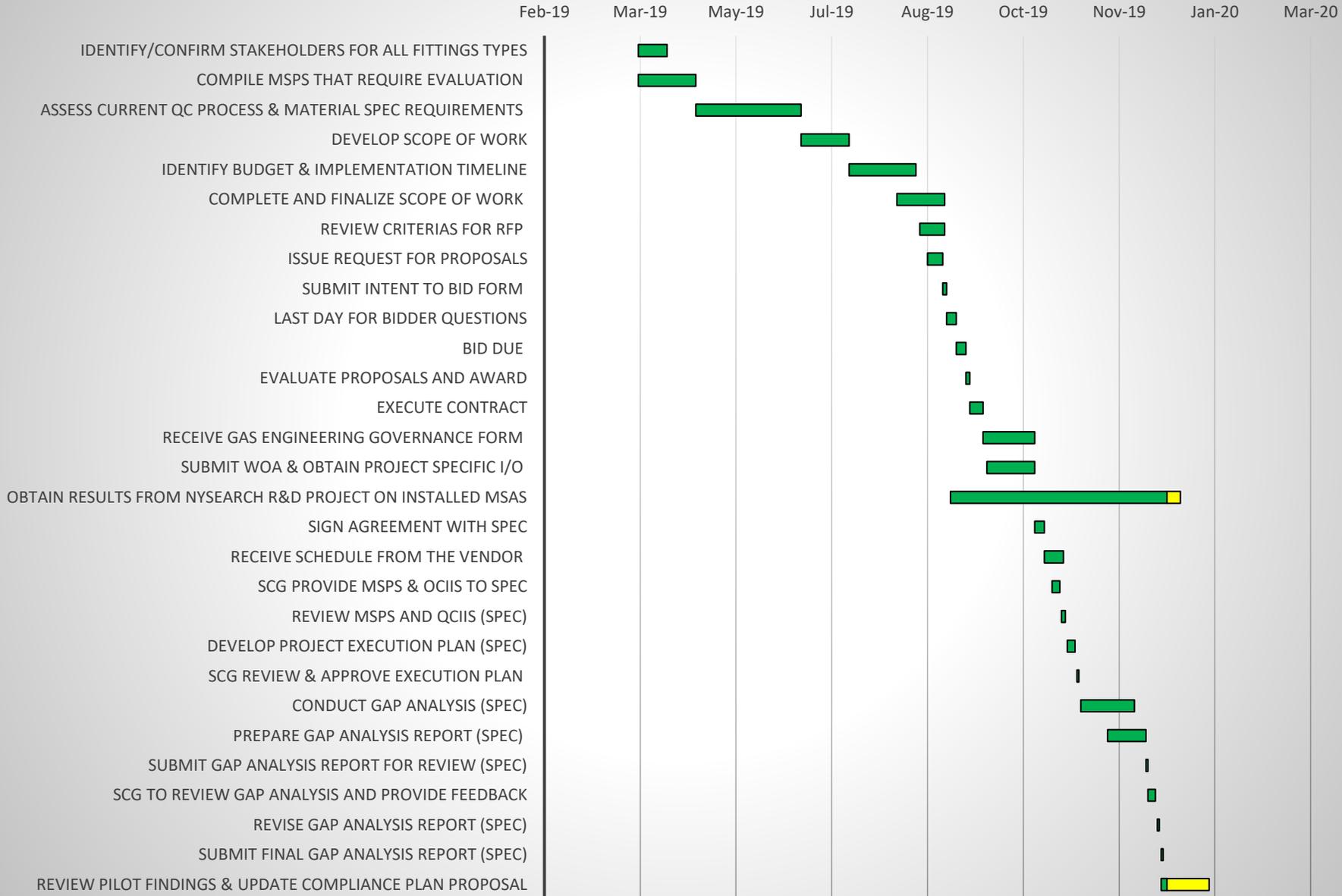
U - Damage Prevention Public Awareness Line Item Cost Breakdown

Name	Actuals	Month	Justification
Ag Expo	\$2,110.87	February	Booth space at World Ag Expo. Safe digging messaging to the largest agriculture trade show in the country.
Excavator Focus Groups	\$70,142.54	March	Pre-testing of communication materials to specific stakeholders within the excavator community to better improve messaging
MarComm expenses to Focus Groups	\$399.93	March	Expenses for MarComm to focus groups
Changes to EX brochures	\$885.00	April	changes made to public awareness brochure based on feedback from excavator focus groups
National Excavator Initiative mailing	\$71,768.30	August	NEI print collateral highlighting damage prevention messaging to excavators
National Excavator Initiative	\$100,000.00	March	Use of NEI Mike Rowe damage prevention PSA videos
National Safe Digging Month	\$75,000.00	April	Damage prevention messaging at Angels Stadium for National Safe Digging Month. Airing of SoCalGas safe digging video at 12 home games, safe digging radio commercial at Angels stadium
National Safe Digging Month Staffing	\$781.53	April	Staffing for damage prevention messaging at Angels Stadium for National Safe Digging Month.
Long Beach Grand Prix	\$5,240.00	April	Damage prevention messaging at the Long Beach Grand Prix along with Shell Oil. Booth space and Big Shovel to communicate safe digging messages to audience at the Expo which about 140K people go through during the weekend of the Grand Prix.
Long Beach Grand Prix staffing	\$2,748.66	April	Staffing to work booth and communicate safe digging message to those attending Long Beach Grand Prix
Residential focus group	\$32,352.74	May	Pre-testing of communication materials to homeowners to better improve messaging and relay message of contacting 811 before digging
811 Campaign	\$141,482.00	August	Damage prevention messaging during timeframe to include 811 Day. Campaign includes in-theater commercial throughout service territory, bus advertising, and 110 freeway digital media
Ventura County Fair	\$3,000.00	August	Damage prevention messaging during the last weekend of the Fair which runs through Aug 11 (811 Day)
Paradigm Excavator Outreach meetings	\$19,780.11	Nov	Additional excavator safety outreach meetings throughout service territory
MarComm expenses to CGA conference	\$5,141.86	March	Expenses for CGA conference participation. MarComm to network and learn with other utilities on how to improve damage prevention messaging.
PAPA supplemental mailers	\$49,368.88	March	PAPA has their own direct mailing program of communication materials to Emergency Responder, Excavator, and Public Official stakeholders and the agricultural community
Next Door App pilot	\$19,214.30	August	Local neighborhood damage prevention outreach using Next Door app and targeting top 25 dig-in zip codes
811 Damage Prevention Float at Rose Parade	\$25,000.00	Nov	Damage Prevention outreach of 811 messaging at the 2020 Rose Parade
Damage prevention outreach display		Oct	displays for damage prevention team to use at outreach events - damage prevention messaging
School Damage Prevention with Culver	\$36,000	Sept	School material on natural gas safety with damage prevention education to schools in the top 25 dig-in zip codes
Home Depot	\$835	Sept	Home Depot printing
Reprint of brochure	\$485	Sept	Excavator brochures for conference
Ag brochure new images	\$425	Sept	
CGA Education Committee Meeting expenses	\$1,643	Nov	Participation in CGA Education Committee Meetings to create toolkits with one-call centers, excavators and operators for damage prevention outreach
Total	\$661,694		

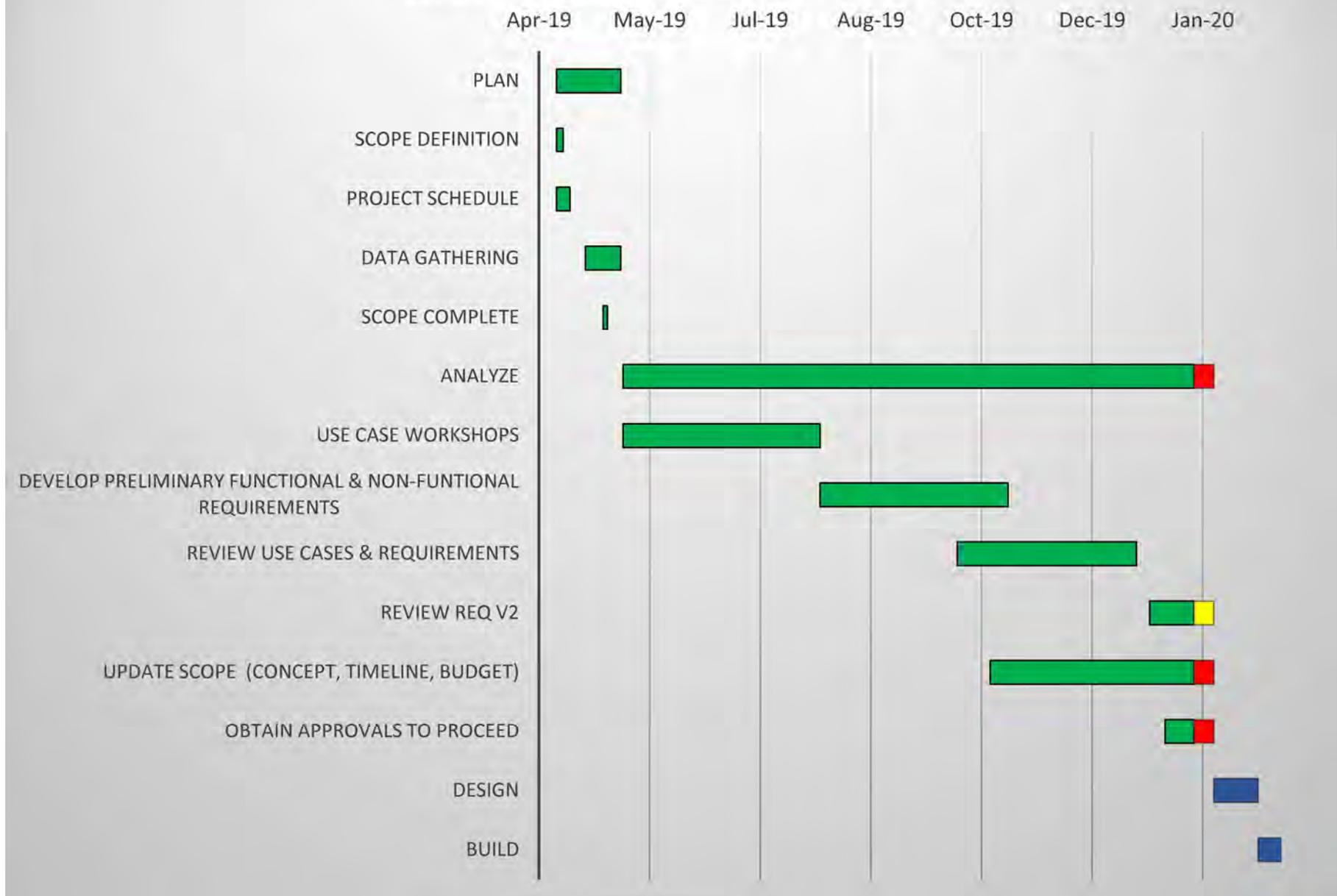
Chapter 15 - Expanded Public Awareness Program



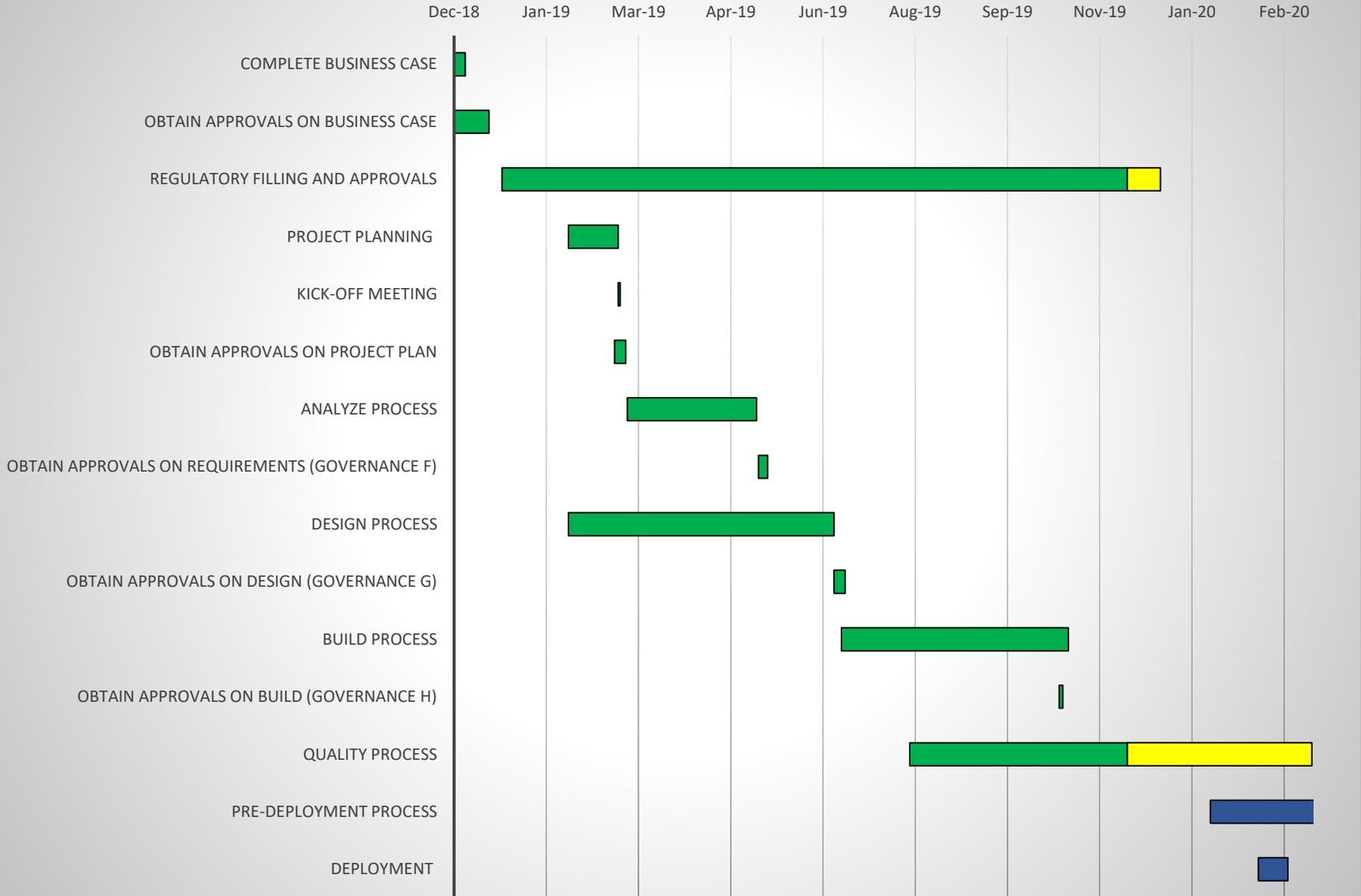
Chapter 16 - Threaded Fittings QC Pilot Project



Ch 17 - Dig-Ins and Repeat Offenders

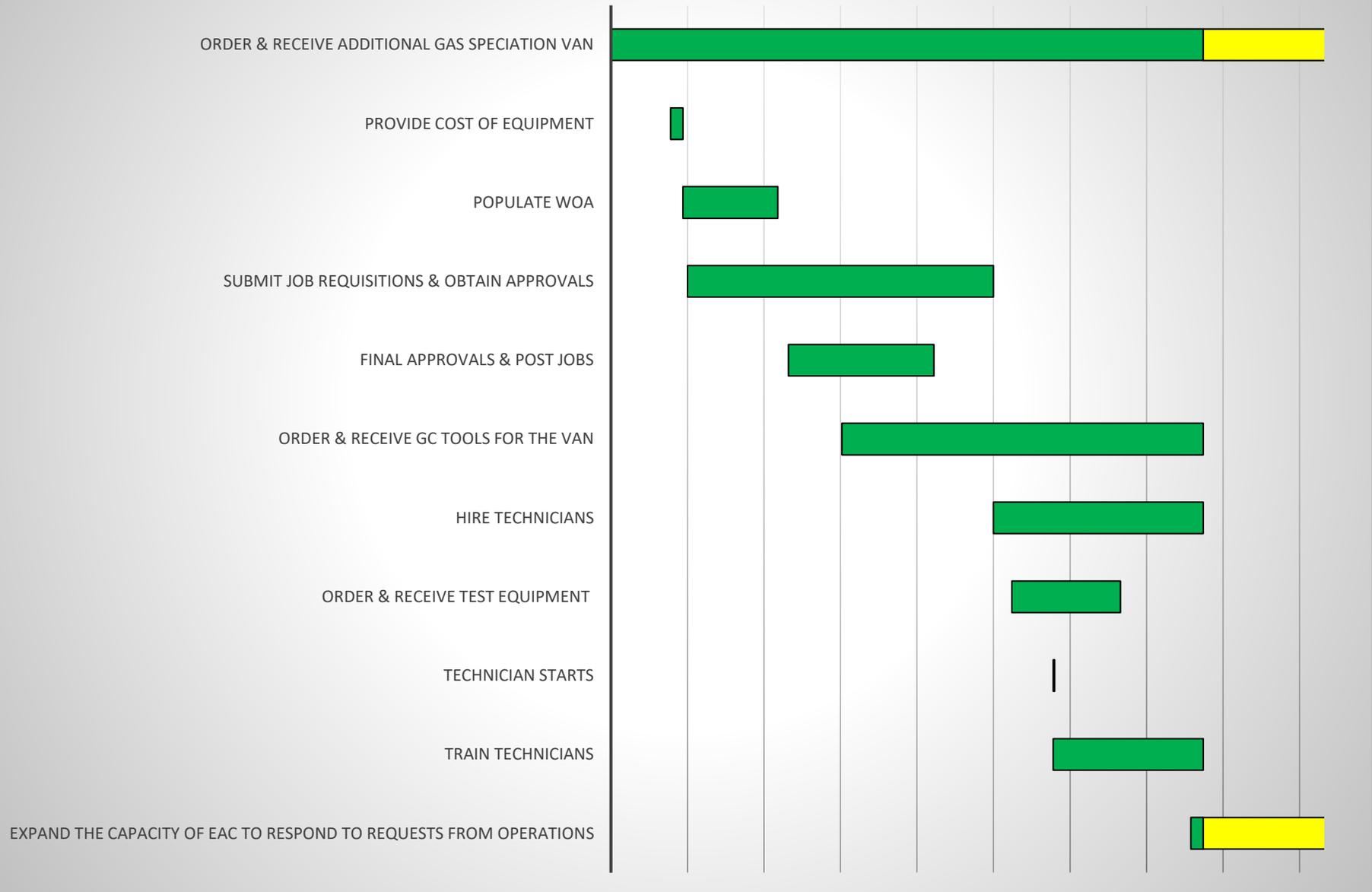


Chapter 18 - Calibration Factor for Fast Meters



Chapter 19 - Enhanced Methane Detection

Dec-18 Jan-19 Mar-19 Apr-19 Jun-19 Aug-19 Sep-19 Nov-19 Jan-20 Feb-20





Environmental Excellence Policy

Responsible Dept.: Environmental Services
Responsible Officer: VP of Operations Support
and Chief Environmental Officer
Applicability: All SoCalGas Employees

ATTACHMENT AA

EFFECTIVE DATE: 05/14/2012

REVIEW DATE: 12/18/2018

REVISION DATE: 12/18/2018

INFORMATION TYPE: Public

Questions?

Contact: Environmental Services

1. POLICY:

Environmental excellence means being a responsible steward of the earth's cultural and natural resources and conserving plant and animal species along with their habitats. SoCalGas is a responsible steward and conducts its activities in a way that protects the current and long-term wellbeing of our employees, the public, and the environment to meet the needs of the present without impacting the ability of future generations to meet their needs. SoCalGas is committed to the following program activities to support Environmental Excellence.

1.1. **Energy Efficiency & Air Quality /Climate Change**

- Energy efficiency is a fundamental element in the progress toward a sustainable energy future. SoCalGas is determined to assist our customers in consuming less energy.
- SoCalGas will continue to focus on delivering a reliable natural gas supply and services that are competitively priced and supports a low-carbon model that includes natural gas, biogas, energy efficiency, clean transportation, distributed generation and innovative technologies that reduce the emission of criteria pollutants and greenhouse gases that contribute to climate change.
- SoCalGas recognizes that methane is a potent Green House Gas that must be prevented from escaping to the atmosphere and supports the activities prescribed in Senate Bills 1371 and 1383 to reduce methane emissions.

1.2. **Natural and Cultural Diversity**

- California is among the top ten biodiversity regions on earth and as a result is rich in natural and cultural resources.
- SoCalGas recognizes the overall challenge of environmental sustainability is the protection of these resources.
- SoCalGas is committed to conducting its operations in a way that promotes the preservation of these resources through coordinated and comprehensive programs of avoidance, minimization and /or mitigation of impacts.
- SoCalGas is further committed to reducing water consumption and preserving water quality through the design and operation of our facilities.

1.3. **Lifecycle of Operations and Other Business Activities**

- SoCalGas is committed to preventing pollution throughout the life cycle of our operations and business activities by improving our environmental management systems. This includes minimizing energy and fuel usage, "greening" procurement practices, maintaining control over the chemical substances and materials used, reducing, substituting, and eliminating substances that have potentially significant impacts, and maximizing the recycling of wastes and byproducts.

You may raise questions or concerns about compliance or ethic issues by visiting our anonymous Sempra Energy Ethics & Compliance Helpline website at www.SempraEthics.com or by calling one of the appropriate

Ethics & Compliance Helplines below:

United States – 800-793-7723
Mexico – 001-770-582-5249

Chile: 600-320-17
Peru: 0800-7-0690



Environmental Excellence Policy

Responsible Dept.: Environmental Services
Responsible Officer: VP of Operations
Support and Chief Environmental Officer
Applicability: All SoCalGas Employees

EFFECTIVE DATE: 05/14/2012
REVIEW DATE: 12/18/2018
REVISION DATE: 12/18/2018
INFORMATION TYPE: Public
Questions?
Contact: Environmental Services

2. BACKGROUND

California is among the top ten biodiversity regions in the United States and as a result is rich in natural and cultural resources. Biodiversity is defined as the existence of a wide variety of plant and animal species in their natural environments. We are committed to protecting, preserving and enhancement of biodiversity in areas where we operate.

SoCalGas uses water in a responsible and sustainable manner, and abides by applicable water related laws, regulations and permit requirements.

Environmental procedures are developed to manage environmental impacts including water reuse, recycling and waste minimization, greenhouse gas and other air emissions reduction programs and air quality improvements.

3. RELATED DOCUMENTS

Environmental Standards and Fact Sheets related to this policy can be found on the [Sempra Utilities Operations Document System](#).

4. INFORMATION RETENTION GUIDANCE

For guidance as to the appropriate retention period for information related to this policy, please refer to the [Information Management Policy](#).

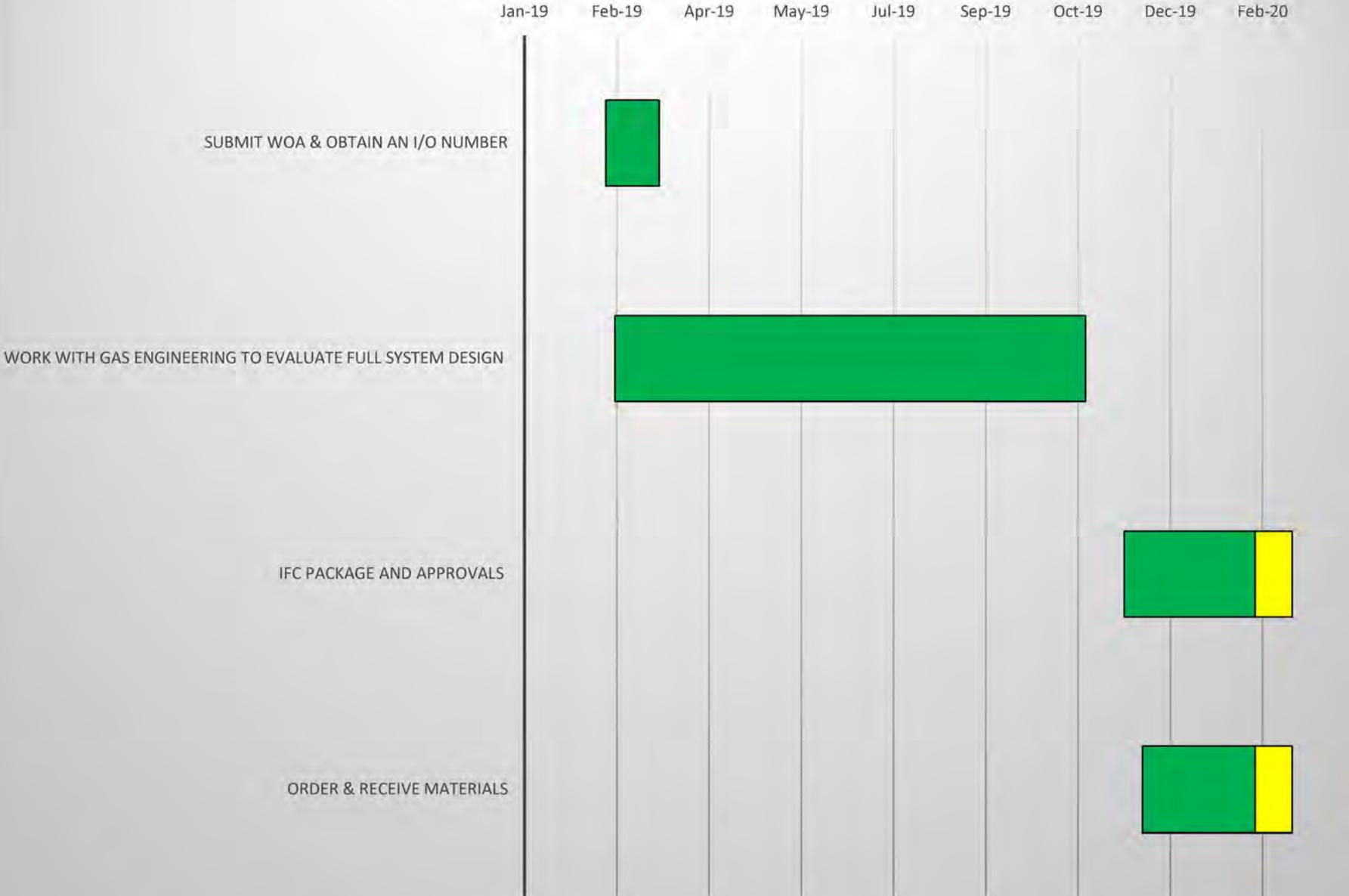
You may raise questions or concerns about compliance or ethic issues by visiting our [anonymous Sempra Energy Ethics & Compliance Helpline website at \[www.SempraEthics.com\]\(http://www.SempraEthics.com\)](#) or by calling one of the appropriate

Ethics & Compliance Helplines below:

United States – 800-793-7723
Mexico – 001-770-582-5249

Chile: 600-320-17
Peru: 0800-7-0690

Chapter 22 - Vapor Collection System



Differential Pressure Testing of Rotary Gas Meters	SCG:	185.0347
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PURPOSE Provide requirements for DP Testing of Rotary Gas Meters to detect mechanical changes which may affect the accuracy of the meter. This method is in place as an effort to avoid any unnecessary release of gas into the environment in accordance with SB-1371 and LAP-23.

1. POLICY AND SCOPE

- 1.1. Differential Pressure testing of medium and large rotary gas meters from 11C to 16M at up to 60.0# can be performed to determine if mechanical changes within the meter have potentially affected the accuracy of the meter, and to comply with General Order 58-A Section 12c.
- 1.2. DP Testing of a Rotary Meter is used as an indicator of the mechanical fitness of a Rotary Meter. It is known in the Gas Industry as a valid indicator of possible accuracy changes due to excessive internal resistance within the meter. It is assumed that meters which have demonstrated they are mechanically fit, that the accuracy of the meter does not change outside of acceptable tolerance. The measurement chamber within the meter body is known to remain at a constant.
- 1.3. Employ the methods in this Company Operations Standard, when feasible, in an effort to reduce the emission of Natural Gas into the Atmosphere to comply with SB-1371 and SCG LAP-BP 23.
- 1.4. Methods in this Gas Standard are intended to reduce the emission of Natural Gas into the Atmosphere. They are not intended to circumvent any pertinent, identifiable maintenance activity. These methods are aimed at MSAs which are in proper operating condition, As Found.
- 1.5. Non-intrinsically safe electrical equipment such as but not limited to laptop computers, cellular phones/devices, pagers, can only be used in a Gas Free Environment. Be sure to follow all applicable safety guidelines when working with /around any natural gas facility and its associated equipment. Reference Gas [Standard 182.0020](#), *Electrical Facilities in Hazardous Areas* and Gas [Standard 166.0025](#), *Prevention of Accidental Ignition of Natural Gas*.

2. RESPONSIBILITIES AND QUALIFICATIONS

- 2.1. Company Field Employees are responsible for adhering to Company procedures and shall wear appropriate personal safety equipment during all duties performed. See Injury and Illness Prevention Program Binder under [Manual IIPP.4](#), Employee's Responsibilities.
- 2.2. Qualified Field Employees are responsible for complying with this Company Operations Standard.

Differential Pressure Testing of Rotary Gas Meters	SCG:	185.0347
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- 2.3. Field Supervision is responsible for ensuring Field Employees are properly trained and can demonstrate a comprehensive knowledge of the proper use and general care of the equipment.
- 2.4. Gas Engineering - is responsible for the rollout training of Field Employees. Gas Operations Training is responsible to provide initial technician training and any subsequent refresher training of Company personnel.
- 2.5. SCG Metrology Laboratory – Pico Rivera is responsible for the initial configuration of the DP Tester, calibration, the set-up of a calibration schedule, the serialization of the DP Tester, and to coordinate any repairs to the instrument to maintain its intrinsically-safe status. Reference Gas Standard 107.0314 *Meriam M201 DN-0200-IS Rotary Gas Meter Tester*.

3. DEFINITIONS

- 3.1. AS FOUND – Condition at which a technician finds a MSA, or component of an MSA upon arrival, before any repair.
- 3.2. DP – Differential Pressure
- 3.3. DP Test – Differential Pressure Test of a meter using the inlet and outlet ports built into a Rotary Meter.
- 3.4. SAP – Systems, Application & Products in data processing
- 3.5. SAP-PM – Plant Maintenance (SAP-PM is the Plant Maintenance module for SAP application)
- 3.6. Click Mobile – (Field mobile application software) – This is the approved Company software that is loaded onto each M&R field technician’s Mobile Data Terminal
- 3.7. LAP-BP 23 – Leak Abatement Program. Section 23 references best practices to reduce emissions related to maintenance activities.
- 3.8. SB1371 – Senate Bill requiring a proactive reduction of the emissions of Natural Gas to the Atmosphere.
- 3.9. MSA – Meter Set Assembly
- 3.10. CFH – Cubic Feet per Hour
- 3.11. PMC – Periodic Meter Change
- 3.12. SDS –Safety Data Sheet

Differential Pressure Testing of Rotary Gas Meters	SCG:	185.0347
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- 3.13. DR – Does not register.
 - 3.14. B3 – Newer Dresser Rotary Meter Body. (See Appendix for picture of B3 Meter Body)
 - 3.15. LMMA – Older, originally oil-filled index Dresser Rotary Meter. The AMI Project upgraded the index to B3 style oil less index with an MTU. LMMA meter is identifiable by its long, rounded-edges body and Nameplate on the back of the meter. (See Appendix for Picture of LMMA Meter Body)
 - 3.16. CHECK PROOF –Known error in a meter at 25% of its Uncorrected Capacity flow rate.
 - 3.17. UNCORRECTED FLOW RATE – Physical volume of gas passing through the meter without any consideration for pressure, temperature, or gas composition.
 - 3.18. PETE’S PLUG – Brass adapter which allows a specialized Pete’s Plug needle to tap in without operating a valve.
 - 3.19. BINDING – A speedup and slowing of a meter caused by bent, or defective parts.
 - 3.20. CODE 90 – An Activity Code in ClickMobile in which a future order is recorded against the equipment in which the Code 90 was set.
 - 3.21. DP Calc – An external program developed by Dresser in which to determine a Pass or Fail of a DP Test.
 - 3.22. AMI DP Test Flow Dashboard – A dashboard created by the AMI Group which contains hourly flow data to help determine ahead of time if a site will likely produce a valid DP Test, according to flows indicated by time.
4. PROCEDURE
- 4.1. M&R Technicians will examine PMC workflow for prospective DP Test candidates using the AMI DP Test Flow Dashboard.
 - 4.1.1. The AMI Dashboard is accessed by the Technician and a GNN with a scheduled PMC or FMT fitting the criteria for a valid test site, is input into the dashboard.
 - 4.1.2. The Technician examines the Dashboard data for data indicating flow of greater than 20% hourly average of the meter’s Uncorrected Capacity per hour.

- 4.1.3. On finding sites with data over 20% flow average in an hour, the Technician sees the hours in which the flow is expected to exceed 20%. The Technician(s) are to attempt to perform the work in a manner set by the Region, or Work Location to not disrupt the flow of work with excessive travel time in order to obtain a DP Test.
- 4.2. M&R Technicians examine their schedule before leaving their base and work eligible DP Testing orders according to timing indicated by the dashboard or by the Lead Technician if a logical route can be determined and not produce excessive travel time.
- 4.3. Before making physical contact with equipment, a test for Voltage is required prior to such contact. Reference Gas [Standard 185.0300](#) *MSA – Installing, Rebuilding and Inspections*.
- 4.3.1. M&R Technician will perform a Rotary Meter Inspection according to Gas [Standard 185.0425](#) *Rotary Meters – Installation, Field Maintenance, Inspection and Repair*
- 4.3.1.1. The technician will observe the operation of the meter and look for any audible, or visual indicators of an anomaly, such as binding, bearing noise, surging, etc. DP Testing is intended for meters with No indicators of a malfunction. Replace any meter which appears questionable.
- 4.3.1.2. The DP Testing tool is not to be connected to any known-malfunctioning meter, nor any suspected DR meter. Damage to the DP Tester may result if the difference in pressure from the inlet port and outlet port exceeds 14 PSIG.
- 4.3.2. Connections to the meter are made through Pete’s Plug adapters fed from the meter’s inlet and outlet ports. Assure there are connection points available.
- 4.3.2.1. DP Tests across the Rotary Meter are always measured in Inches of Water Column at 60 Degrees Fahrenheit (inW@60F), no matter the metering pressure.
- 4.3.2.2. Use ONLY Pipe Thread Tape to seal any fittings or adapters to be connected to the DP testing instrument.
- 4.3.2.3. Assure Pete’s Plug connections at the meter are impeccably clean. The opening in the DP Tester’s Pete’s Plug needles are very small and can plug easily.

Company Operations Standard Gas Standard Gas Engineering

Differential Pressure Testing of Rotary Gas Meters

SCG:

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- 4.3.2.4. Prepare the meter to assure there are Pete's Plug adapters on both the inlet and outlet ports of the meter and remove caps. It is ok to install Pete's Plug adapters over needle valves.
- 4.3.2.5. Open any needle valves to expose the Pete's Plug adapters to pressure, if necessary.
- 4.3.2.6. Do not use oil or grease to lubricate the Pete's Plug needles. Water is the only acceptable lubricant for the Pete's Plug needle to assist in insertion.
- 4.3.3. InWc and up to 5 PSIG Metering Pressure hookup procedure:
- 4.3.3.1. After physical and audible examination and a determination that there are no known anomalies, connect the hoses to P1 and P2 ports of the DP Tester, respectively.
- 4.3.3.2. With both hoses plugged into the tester only, power on the DP Tester and check for Zeroing of the tester. Zero the tester, if necessary.
- 4.3.3.3. Connect the P1 hose to the inlet port of the meter to be tested through a Pete's Plug adapter.
- 4.3.3.4. Examine the display on the Meriam tester and assure the display indicated DP while the device purges through the hose connected to P2 while still at Atmosphere. No, or very low DP during an expected flow through the P2 hose indicates a restricted or plugged hose(s). Perform this examination in a quick, orchestrated manner as gas will be escaping through the needle.
- 4.3.3.5. Connect the hose from P2 to the outlet port of the meter.
- 4.3.3.6. Seat both needles fully by tightening the fasteners (hand tight) onto their adapters.
- Note: DP Testing is only accurate when pressure is supplied by the ports of the meter. Do not make connections outside of the meter body port connections.
- 4.3.3.7. Assure all connections are leak free.
- 4.3.4. Over 5# Metering Pressure and up to 60#
- 4.3.4.1. Prepare the set to assure there are Pete's Plug adapters on both the inlet and outlet ports of the meter and remove caps.

Company Operations Standard Gas Standard Gas Engineering

Differential Pressure Testing of Rotary Gas Meters

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- 4.3.4.2. After physical and audible examination and a determination that there are no known anomalies, then connect a hose to P1 side of the DP Tester and to the pressurized inlet port of the meter to be tested through a Pete's Plug adapter.
- 4.3.4.3. Do Not Depress the PTR valve on the DP Tester until ALL connections (P1 AND P2) intended are made. Unintentional damage to the tester could result.
- 4.3.4.4. Close the needle valve to trap inlet pressure between the device and the meter.
- 4.3.4.5. Zero the device.
- 4.3.4.6. Open the needle valve on the inlet port fully.
- 4.3.4.7. Connect the second hose onto the DP Tester P2. Assure there is DP showing on the device while the P2 hose is exposed to Atmosphere and the device is purging. No DP or very low DP indicates a restriction or plug in the hose. Perform this examination in a quick, orchestrated manner as gas will be escaping through the needle.
- 4.3.4.8. Install the Pete's Plug needle from P2 into the Pete's Plug adapter on the outlet side of the meter.
- 4.3.4.9. Seat both needles fully by tightening the fasteners (hand tight) onto their adapters.
- 4.3.4.10. When disconnecting from a meter with metering pressure above 5 PSIG, Do Not Depress the PTR button with any hose disconnected from the meter or damage may occur.
- 4.3.4.11. Assure all connections are leak free.
- 4.3.5. When the meter is determined to meet or exceed an Uncorrected Flow rate of 30% or better and less than 120% of its capacity, depress and hold the PTR Valve on the DP Tester manifold to isolate the DP Sensor. (See Appendix for Job Aid sheet, if desired, to quickly determine if meter is running between 30 and 120%.)
- 4.3.5.1. Press the "Hold" button on the DP Tester to start the test and note the number of the segment on the Test Dial the test is started at.
- 4.3.5.2. Stop the test after a minimum of 25 seconds has elapsed by pressing the "Hold" button.

Company Operations Standard Gas Standard Gas Engineering

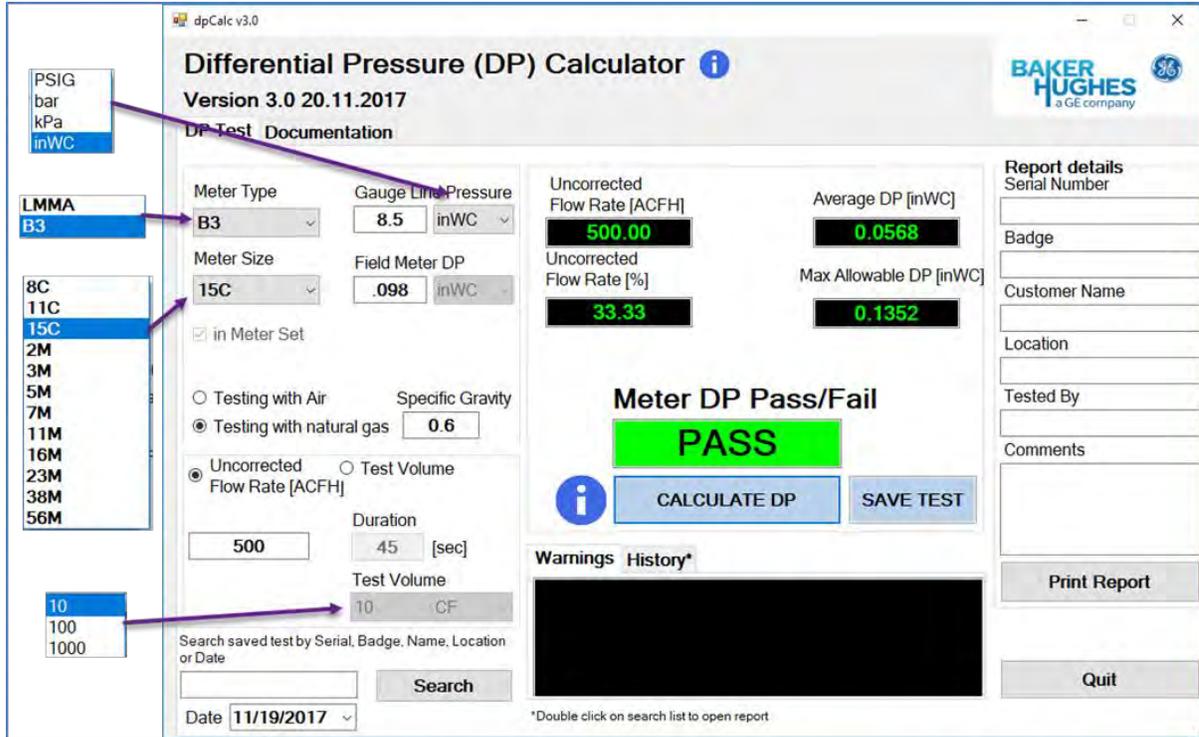
Differential Pressure Testing of Rotary Gas Meters	SCG:	185.0347
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- 4.3.5.3. Note the number of the segment now on the Test Dial after stopping the test. Calculate the total number of CF passed during the test.
- 4.3.5.4. The DP Tester will indicate the duration of your test via its internal stopwatch. The average flow rate can be determined using the CF of gas passed during the test and the duration of the test in seconds. (Formula: $3600 \div \text{Test Duration in Seconds} \times \text{CF of gas passed during test interval}$. Use a Job Aid, if desired, to easily compute the flow rate using elapsed time and CF of gas passed during the test)
- 4.3.5.5. Tests with vast differences in flow rate (Heavy Surging) during the test, or under 25 seconds are not valid. A test can be restarted by pressing the “Hold” button after a previous test has been stopped.
- 4.3.6. Start the Dresser DP Calc program and input values into the fields. (Meter type tested, Meter Pressure (Gauge Line Pressure), Meter Capacity, DP Average Test Result, Test with Gas, Flow Rate during test interval) Press Calculate to see PASS or FAIL result.

4.3.6.1. DP Calc Fields:

Meter Type	LMMA or B3
Gauge Line Pressure	Enter Meter Pressure and select inWC or PSIG in the drop-down menu.
Meter Size	Select the appropriate Meter Size from the drop-down menu.
Field Meter DP	Enter your DP Test result from the DP Tester. (DP across the Rotary Meter is always measured in inWC.)
Select Radio Button	“Testing with natural gas”
Specific Gravity	“0.6”
Select Radio Button	Uncorrected Flow Rate
	Enter your Uncorrected Flow Rate calculated during the test interval. Do not round off. Use calculated whole number. (ACFH)
	OR
Select Radio Button	Test Volume
	Enter the Duration of the test, as indicated on the DP Tester, in seconds.
	Enter the Test Volume passed during the test. (Choices are 10, 100, 1000 One complete revolution of the Test Hand drum.)

- 4.3.6.2. Press the CALCULATE DP Button to calculate the results.



4.3.7. Test Results Fields after CALCULATE DP button pressed

Name of Field:

Uncorrected Flow Rate (ACFH)

Uncorrected Flow Rate %

Average DP (inWC)

Max. Allowable DP (inWC)

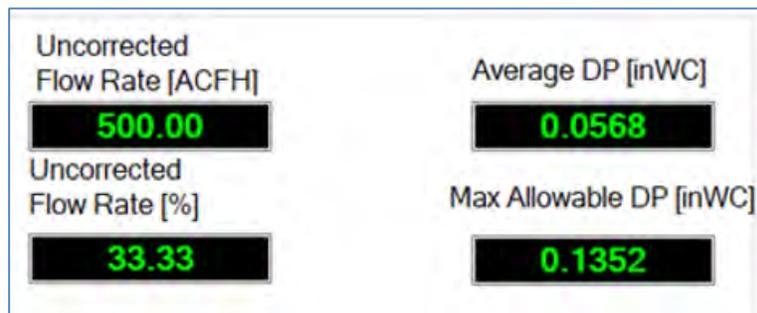
Meaning of Number in Field

Rate of Flow during Test.

Flow Rate in % of Capacity.

Base Average DP found in Dresser DP database.

Max. allowable DP for a PASS Test.



Company Operations Standard Gas Standard Gas Engineering

Differential Pressure Testing of Rotary Gas Meters	SCG:	185.0347
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4.3.8. Meter DP Test Pass/Fail

PASS

Record Results in ClickMobile under [Form CM-5430 Rotary Meter Inspection & Field Meter Test Results](#). Use Condition Code 16 Differential Test PASS. Carry over the Historical Checkproof into the “Corr Accy” field in the FMT form.

FAIL

RMC/PMC meter. Do not fill in FMT Form in ClickMobile; instead fill in the Meter Changeout form (PMC) and indicate Failed DP Test in the Facility Tab “Remarks” section.

OR

Record failed test in ClickMobile in [Form CM-5430 Rotary Meter Inspection & Field Meter Test Results](#) if you are not going to change the meter while you are onsite and need to complete the order. Use Condition Code 18 Differential Test Fail. Set Activity Code 90 to replace the meter. Fill in Differential Pressure field and Flow Rate field of form with test info. **Do Not** carry over the meters historical accuracy as it has likely changed. Indicate in Remarks in the order of failed test and need to replace the meter.

4.3.9. Filter Inspection

4.3.9.1. Upon a DP Test PASS, the filter inspection can be an external inspection and recorded in ClickMobile [Form CM-5480 Filter Inspection](#). This is allowable at this point to reduce Natural Gas vented to Atmosphere, since the set will not be broken-down and to comply with SB-1371. It is presumed that with the flow rate exhibited during the test, and no anomalies observed, that the filter has physically demonstrated it is not plugged.

4.3.9.2. You may replace the filter element on High Mileage customers as best practice.

4.3.9.3. Any MSA with a known filter issue, or if you suspect a filter problem, pressure issue, or leak, inspect the filter internally.

4.3.9.4. Any Area your District considers to have particulates in the gas stream in excess, and decides it prudent to inspect filters within this Area, may do so to prevent issues in the future.

4.3.10. Spot Test

4.3.10.1. The Meriam M201 can be used to perform a Spot Test. Reference Gas Standard 107.0314 *Meriam M201 DN-0200-IS Rotary Gas Meter Tester* for device setup information. The test pressure result obtained while the Rotary Meter is running at over 20% of its UnCorrected capacity is valid so long as it is within the +/- 2% tolerance.

4.3.10.2. Under no circumstances is delivery pressure allowed to be adjusted while the downstream valve is open. Any test where the pressure is out of tolerance will require adjustment with the customer bypassed; against a closed valve and at a minimal bleed.

Note: A Spot Test is a verification of metering pressure; it is not a setpoint. After proper setting of the regulator at a minimum bleed, if a MSA fails the Spot Test, determine the cause of the failure and correct it.

4.3.11. Regulator Inspection

4.3.11.1. Bypass the MSA and perform your inspection of the regulator as normally done. Perform all maintenance deemed necessary to correct any issue with regulator(s) irrespective of a passed DP Test result. A passed DP Test is not intended to omit any necessary maintenance activities.

4.3.12. ClickMobile [Form CM-5430](#) *Rotary Meter Inspection & Field Meter Test Results.*

4.3.12.1. FMT Test Results

4.3.12.1.1. On a Failed DP Test which you will change the meter while onsite, do not fill in the FMT portion of the form. Fill in the Rotary Meter Inspection results of the form only; close the form and complete a PMC of the meter in ClickMobile.

4.3.12.1.2. CHECK Fields

4.3.12.1.2.1. Flow Rate is prepopulated and Read Only.

Company Operations Standard Gas Standard Gas Engineering

Differential Pressure Testing of Rotary Gas Meters

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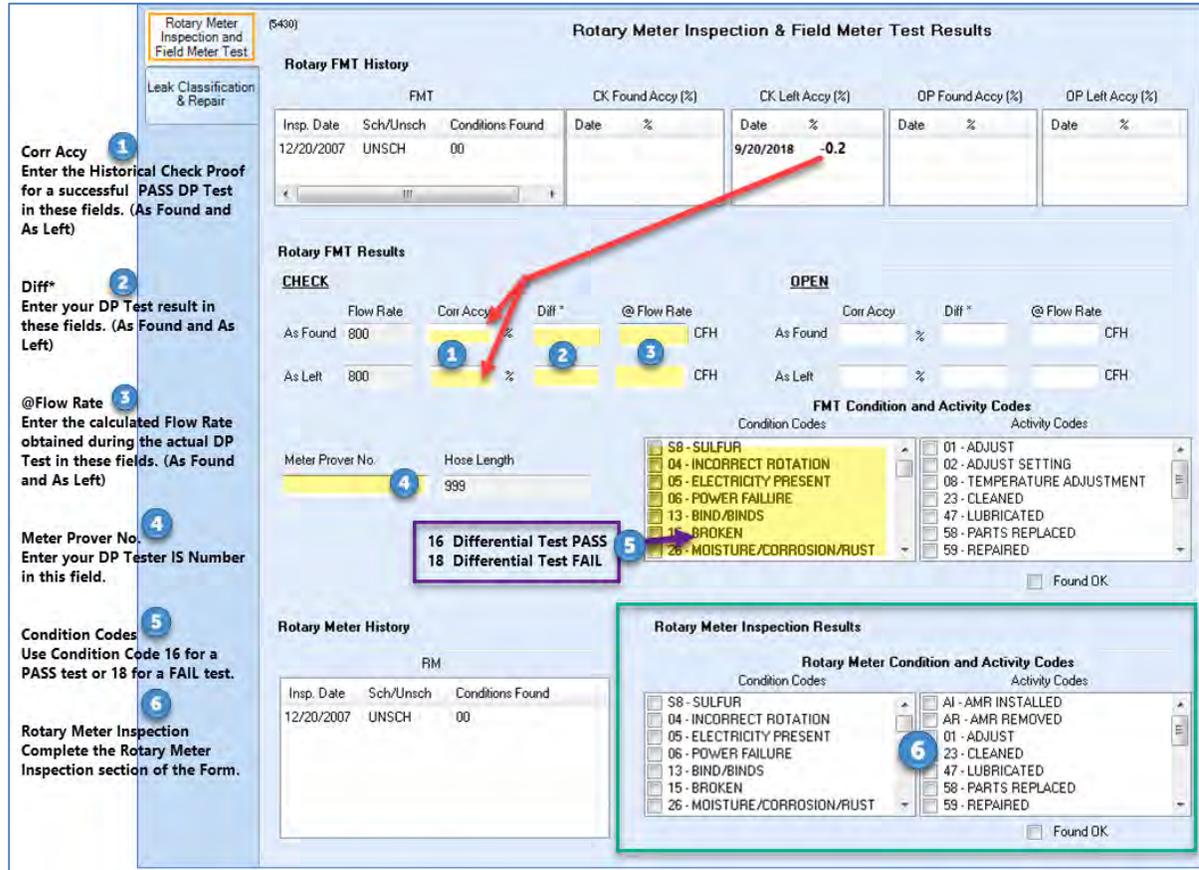
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- 4.3.12.1.2.2. On a PASS test enter your Historical Check Proof in the As Found and As Left Cor Accy Fields. Do not fill in this field for a failed test.
- 4.3.12.1.2.3. Enter your DP Test result in the Diff* Field.
- 4.3.12.1.2.4. Enter your calculated Flow Rate from your actual DP Test result. Do not round whole numbers.
- 4.3.12.1.2.5. Enter the DP Tester IS# in the Meter Prover field.
- 4.3.12.1.2.6. Check Condition Code 16 Differential Test PASS for a successful, passing DP Test.
- 4.3.12.1.2.7. Check condition Code 18 Differential Test Fail for a failed DP Test only if you are not going to change the meter during your visit. You will need to set a Code 90 Activity Code to future replace the defective meter.
- 4.3.12.1.2.8. Do not check Found OK checkbox on the FMT portion of the form.

4.3.12.2. Rotary Meter Inspection Results

- 4.3.12.2.1. Fill in the Rotary Meter Inspection portion of the form with any relevant Condition Codes, Activity Codes, or Found OK Checkbox, if applicable.

Differential Pressure Testing of Rotary Gas Meters	SCG:	185.0347
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Rotary Meter Inspection & Field Meter Test Results

Rotary FMT History

FMT			CK Found Accy (%)		CK Left Accy (%)		OP Found Accy (%)		OP Left Accy (%)	
Insp. Date	Sch/Unsch	Conditions Found	Date	%	Date	%	Date	%	Date	%
12/20/2007	UNSCH	00			9/20/2018	-0.2				

Rotary FMT Results

CHECK

Flow Rate	Corr Accy	Diff *	@ Flow Rate	CFH
As Found: 800	%	%		
As Left: 800	%	%		

OPEN

Flow Rate	Corr Accy	Diff *	@ Flow Rate	CFH
As Found:	%	%		
As Left:	%	%		

Meter Prover No. _____ Hose Length: 999

FMT Condition and Activity Codes

Condition Codes	Activity Codes
<input checked="" type="checkbox"/> S8 - SULFUR <input checked="" type="checkbox"/> 04 - INCORRECT ROTATION <input checked="" type="checkbox"/> 05 - ELECTRICITY PRESENT <input checked="" type="checkbox"/> 06 - POWER FAILURE <input checked="" type="checkbox"/> 13 - BIND/BINDS <input checked="" type="checkbox"/> 15 - BROKEN <input checked="" type="checkbox"/> 26 - MOISTURE/CORROSION/RUST	<input type="checkbox"/> 01 - ADJUST <input type="checkbox"/> 02 - ADJUST SETTING <input type="checkbox"/> 08 - TEMPERATURE ADJUSTMENT <input type="checkbox"/> 23 - CLEANED <input type="checkbox"/> 47 - LUBRICATED <input type="checkbox"/> 58 - PARTS REPLACED <input type="checkbox"/> 59 - REPAIRED

Rotary Meter History

Insp. Date	Sch/Unsch	Conditions Found
12/20/2007	UNSCH	00

Rotary Meter Inspection Results

Rotary Meter Condition and Activity Codes

Condition Codes	Activity Codes
<input type="checkbox"/> S8 - SULFUR <input type="checkbox"/> 04 - INCORRECT ROTATION <input type="checkbox"/> 05 - ELECTRICITY PRESENT <input type="checkbox"/> 06 - POWER FAILURE <input type="checkbox"/> 13 - BIND/BINDS <input type="checkbox"/> 15 - BROKEN <input type="checkbox"/> 26 - MOISTURE/CORROSION/RUST	<input type="checkbox"/> A1 - AMR INSTALLED <input type="checkbox"/> AR - AMR REMOVED <input type="checkbox"/> 01 - ADJUST <input type="checkbox"/> 23 - CLEANED <input type="checkbox"/> 47 - LUBRICATED <input type="checkbox"/> 58 - PARTS REPLACED <input type="checkbox"/> 59 - REPAIRED

16 Differential Test PASS
18 Differential Test FAIL

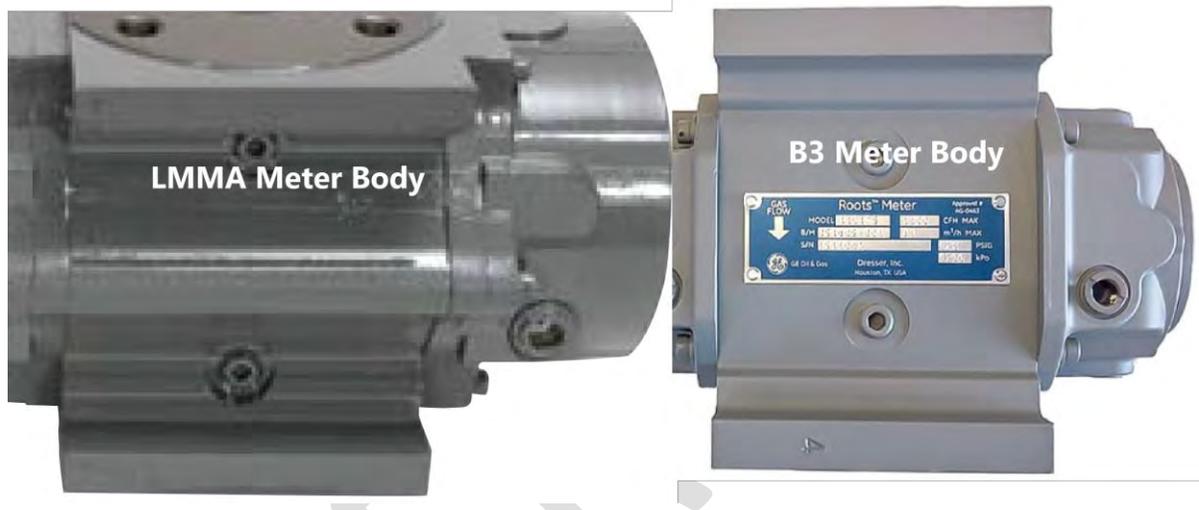
5. EXCEPTION PROCEDURE
(See [GS 182.0004](#), *Exception Procedure for Company Operations Standards*)
 - 5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.
 - 5.2. An exception from a standard shall not be allowed unless [GS 182.0004](#), *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

Differential Pressure Testing of Rotary Gas Meters	SCG:	185.0347
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6. RECORDS

- N/A

7. APPENDICES (if applicable)



Range of Seconds per Segment for Valid DP Testing Range										
	Un-Corrected Values ONLY							Not Approved 23-56M		
	11C	15C	3M	5M	7M	11M	16M	23M	38M	56M
Maximum Seconds Per Segment	10.9	8	4	2.4	1.7	1.1	7.5	5.2	3.1	2.1
Minimum Seconds Per Segment	2.7	2	1	0.6	0.43	0.27	1.88	1.30	0.79	0.54
Test Hand Value	10	10	10	10	10	10	100	100	100	100
Amount of Gas Per Segment	1	1	1	1	1	1	10	10	10	10
Minimum CFH Flow for 30%	330	450	900	1500	2100	3300	4800	6900	11400	16800
Maximum Flow for 120%	1320	1800	3600	6000	8400	13200	19200	27600	45600	67200

Reading CF from Test Hand Dials

Rotary Meter Display 5 Digits 11C175 to 11M175 w/10 CF Test Hand

Each complete rotation of this dial is equivalent to 10 CF of gas. Each individual segment is valued at 1 CF of gas.

Rotary Meter Display 6 Digits 16M175 w/100 CF Test Hand

Each complete rotation of this dial is equivalent to 100 CF of gas. Each individual segment is valued at 10 CF of gas.

Test Hand On EC

15C175 to 11M175 Test Hand value is 10 CF of gas per revolution of the test hand dial. Each segment value is 1 CF of gas.

Test Hand On EC

16M175 Test Hand value is 100 CF of gas per revolution of the test hand dial. Each segment value is 10 CF of gas.

Eagle EC

Bottom Disk runs at Wiggler Speed, or Test Hand value.

15C175 to 11M175 = 10CF per revolution
Each segment = 1 CF

16M175 = 100 CF per revolution
Each segment = 10 CF



Company Operations Standard Gas Standard Gas Engineering

Differential Pressure Testing of Rotary Gas Meters	SCG:	185.0347
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Part of Non-O&M Parts 191-193 Plan	No
Non-O&M 49 CFR Codes & Impacted Sections of Document	
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Part of Transmission IMP (TIMP)	No
Part of Storage IMP (SIMP)	No
Impacts GO112F	No
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Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	Yes
GO58A Codes & Impacted Sections of Document	58A-12c: Entire Document
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Blue Boot XP2i Crystal Gauge Operation, Calibration, and Maintenance Procedures.	SCG:	107.0313
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PURPOSE To provide operational, maintenance and ordering instructions for the Blue Boot XP2i Crystal Gauge.



1. POLICY AND SCOPE

- 1.1. Qualified users of the equipment shall follow the instructions provided within this standard and shall maintain the equipment with care to prevent damage to all components of the gauge kit.
- 1.2. **Non-intrinsically safe electrical equipment such as but not limited to** laptop computers, cellular phones/devices (except an iPhone), pagers, **can only be used in a Gas Free Environment.** Be sure to follow all applicable safety guidelines when working with /around any natural gas facility and its associated equipment. Reference [STANDARD 182.0020](#), *Electrical Facilities in Hazardous Areas* and [STANDARD 166.0025](#), *Prevention of Accidental Ignition of Natural Gas*.

2. RESPONSIBILITIES AND QUALIFICATIONS

- 2.1. **Company Field Employees** are responsible for adhering to Company procedures and shall wear appropriate personal safety equipment during all duties performed. See Injury and Illness Prevention Program Binder under [Manual HPP.4](#), *Employee's Responsibilities*.
- 2.2. **Qualified Field Employees** are responsible for complying with this Company Operations Standard.
- 2.3. **Field Supervision** is responsible for ensuring Field Employees are properly trained and can demonstrate a comprehensive knowledge of the proper use and general care of the equipment.
- 2.4. **Customer Service Training and Development** - is responsible for the initial training and any refresher training for company personnel.

Blue Boot XP2i Crystal Gauge Operation, Calibration, and Maintenance Procedures.	SCG:	107.0313
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- 2.5. **SCG Metrology Laboratory – Pico Rivera** is responsible for the repairs, calibration of the equipment, and purchasing of equipment or related software programs.
3. DEFINITIONS
- 3.1. **ACTUAL PRESSURE** - A pressure measurement at a specific moment in time.
- 3.2. **BACKLIGHT** - Display illumination.
- 3.3. **CAL DUE** - When flashing on the display, indicates that the gauge has reached/exceeded its calibration certification date (on later models).
- 3.4. **CAL SOON** – Appears during start-up when the gauge is approaching its calibration certification date (on later models).
- 3.5. **CLEAR** - Button in the DataLoggerXP software which will erase all stored recordings in the XP2i gauge.
- 3.6. **DATALOGGER** - Feature in the Xp2i gauge which records gauge pressure at predetermined intervals. Records are available to retrieve/view/save using DataLoggerXP software.
- 3.7. **DATALOGGERXP** - A software program specifically designed to retrieve/view/save recordings stored in the XP2i gauge.
- 3.8. **DOWNLOAD** - DataLoggerXP function used to retrieve data recording from the XP2i gauge.
- 3.9. **EVENT** - Non-data readings, optionally displayed as part of a run. These include tare values, low battery indications, or logging parameters.
- 3.10. **FULL** - Indicator on the display which indicated that the memory is completely used and the DataLogger is not recording.
- 3.11. **MESSAGE STORE** - A field populated by the **Metrology Lab** showing the Company-assigned gauge number.
- 3.12. **N.I.S.T.** – National Institute of Standards and Technology.
- 3.13. **NO AUTO OFF** – Appears during startup if the (AUTO OFF) feature is disabled.
- 3.14. **OFF** – Appears on-screen when data logging is off when (UNITS) button is pressed momentarily.

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- 3.15. **ON** – Appears on-screen when data logging when (UNITS) button is pressed momentarily.
 - 3.16. **OVERPRESSURE** - An event when the gauge is exposed to a pressure over its range.
 - 3.17. **REC** - DataLogger mode indicating icon.
 - 3.18. **USER** – A preselected unit equal to PSI with 0.01 PSI resolution. Setting has been programmed into the gauge for Customer Service-Field by the **Metrology Lab**.
 - 3.19. **ZERO** - Button used to set a 0.00 when vented to atmosphere.
4. PROCEDURE

4.1. **Gauge Features:**

Note: SoCal Gas uses a variety of pressure ranges and gauge configurations to list within these instructions. The instructions given in the standard are general and generic to all variations for the gauge. For any questions concerning a specific pressure and gauge configuration, see [Section 4.3](#) for instructions.

- 4.1.1. The XP2i is equipped with a Data Logger capable of recording 32,000 data points.

Note: The Datalogger function is only active on gauges in which the Company has purchased this function.

- 4.1.2. The XP2i displays “CAL SOON” briefly on the display screen when the gauge is approaching (30 days from) its calibration due date (on later models).
- 4.1.3. The XP2i also displays “CAL DUE” as a continuous flashing on the display screen when the gauge has reached its calibration due-date (on later models).
- 4.1.4. The XP2i is expected to operate approximately 1,500 hours before needing a battery replacement (no backlight) and indicated by a battery icon on the lower-left corner of the display.
- 4.1.5. The XP2i is required to be calibrated annually (once per year) per [STANDARD 107.0390](#), *Meter/Measurement Equipment – Handling, Storing and Shipping*. A legible calibration sticker is to be attached by the **Metrology Lab** to the backing plate of the gauge body - **Figure 1**.

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Figure 1

Note: A gauge which has reached/exceeded its calibration shall not be used for any procedures. Any gauge measurement used while expired is considered invalid. Return the gauge to the **Metrology Lab** for calibration immediately.

4.2. Gauge Functions:

4.2.1. **Power Button** turns on and off the gauge. Press and hold the button to power it on – press and release the button to power the gauge off – **Figure 2.**



Figure 2

4.2.2. **Units Button** causes the XP2i to change the engineering units of measure. (USER) is a special setting for Customer Service Field, which are set to read in PSI with a 0.01 PSI resolution (two digits to the right of the decimal). Pressing the (UNITS) button allows the operator to switch between (USER) (PSI and H2O inches of water) engineering units. The gauge will read a maximum of (units with a range of 0-30 will measure up to 30 psig and 830 inches of water) - **Figure 3.**



Figure 3

4.2.3. **Peak Button** will cycle you through different measurement modes and is also used to operate the datalogging function of the gauge, if so equipped, labeled as (REC) in the upper-left corner of the display when in the recording mode - **Figure 4.** When the gauge is in Hi, Lo, or Avg. mode, the reading will not indicate instantaneous pressure.



Figure 4

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- 4.2.3.1. **HI:** Maximum detected pressure.
- 4.2.3.2. **LO:** Minimum detected pressure.
- 4.2.3.3. **AVG:** Average pressure.
- 4.2.3.4. **REC:** Datalogger in logging mode.
- 4.2.4. **Zero Button** is used to zero the gauge before taking a measurement - **Figure 5.**



Figure 5

Note: Do not Zero the gauge with pressure applied. Always Zero the gauge with the measuring point exposed to atmosphere. Never disconnect the gauge without first relieving pressure applied to the gauge. If the gauge is already vented and reading zero, there is no need to zero the gauge.

- 4.2.5. The (AUTO OFF 20) function is disabled. The gauge will default to (NO AUTO OFF) when it is turned on and will remain on until it is physically turned off, or the battery runs out.

Note: During the rollout of the newer model Blue-Boot XP2i gauges, the (AUTO OFF) function was set to (20) minutes and cannot be changed in the field. All newer model gauges returned to the **Metrology Lab** for calibration will have this function changed to (NO AUTO OFF) by default.

- 4.2.6. **Backlight Button** turns the display backlight on. A brief press will illuminate the display temporarily. Holding the button for (1) or more seconds will cause the backlight to illuminate and remain lit. The display will “blink” 1x indicating the mode has been changed. Pressing it a second time will allow the backlight to remain lit in the low power setting. Pressing it a third time will turn the backlight off - **Figure 6.**



Figure 6

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4.2.7. **Overpressure:** The Gauge will continue to display a pressure reading up to 110% of full scale. If the Gauge exceeds 110%, the Display will show +OL and not display any pressure reading. The Gauge may need replacing if it is over-pressured.

4.2.7.1. If over-pressured, return the gauge to the **Metrology Lab** for inspection/calibration. If replacement of the gauge is necessary, the **Metrology Lab** will advise the immediate Supervisor.

4.2.8. **Reset:** If for some reason the XP2i needs to be reset, remove any battery for at least one minute, then reinstall the battery. If the reset is successful, the XP2i will re-start without pressing the (ON/OFF) button. Reset will clear the zero, peak values will be reset to the current reading.

4.3. **Gauge Configurations:**

4.3.1. There are several departments that utilize variations of the gauge and the configurations on how and what the gauges displays when taking pressure. For any questions concerning the operation of the gauge, contact the Distributor of the equipment:

Wilmington Instrument Co., Inc.
Doug Larson
PH: (310) 834-1133
Email: doug@calcert.com

4.4. **Datalogging:**

4.4.1. Contact the **Metrology Lab** for assistance with purchasing the necessary access key for the software:

PH: (562) 806-4373.

4.5. **Accuracy – Gauge Pressure:**

4.5.1. Gauges must be exercised whenever exposed to significant changes in environmental conditions to achieve these specifications, and then re-zeroed:

4.5.1.1. To exercise a gauge, cycle the gauge between zero (atmospheric pressure) and the pressure of interest. A properly exercised gauge will return to a perfect zero reading (or return to the same atmospheric reading).

4.5.1.2. Exposure to environmental extremes of temperature, shock (dropping), and/or vibration may affect accuracy and possibly warrant a more frequent recertification period.

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4.6. **Maintenance:**

4.6.1. **Battery Indicator:**

4.6.1.1. The battery Indicator contains three segments. As the battery energy is depleted, a segment will disappear. The gauge will function so long as the battery Indicator is visible. When the battery is exhausted, the display will show BATT and the gauge will not function – **Figure 7**.

Battery Indicator: () = Full Battery; () = Used Battery; () = Low Battery.

Figure 7

4.6.2. **Batteries and Replacement:**

4.6.2.1. Remove the (4) screws on the back cover and lift the cover to expose the (3) AA Batteries. Replace the batteries and install the cover. The gauge will be on by default without pushing the Power button. This is normal and shows that a Reset has occurred. “Set Date” will flash on the display.

Note: Do not mix battery types. Do not change batteries in a hazardous location.

4.6.2.2. The XP2i is Intrinsically Safe only if powered by the currently approved and stock coded batteries:

- Rayovac Max Plus 815.

4.6.2.3. Many other battery types and models have been tested but failed to meet the requirements for Intrinsic Safety - Do not assume other models are equivalent.

4.6.3. **General Care:**

Note: SoCal Gas utilizes several iterations of the gauge depending on the age. The information is not all inclusive. Extreme care and handling of the gauge and components will greatly enhance the life of the equipment.

4.6.3.1. ALWAYS use a Back-up wrench on the adapter or remove the adapter from the gauge when installing a fitting onto the adapter fitting for the XP2i. The outer case of the gauge should never be subjected to rotational forces. The adapter fitting is tightened finger-tight into the gauge.

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4.6.3.2. Do not use liquid sealant on any of the threads attached to the gauge, the adapter, or the gauge stack. Using only Pipe Thread Tape on fittings to the stack.

Note: Do not use any type of sealant to the adapter fitting end entering the gauge.

4.6.3.3. Periodically wipe the gauge off with a damp rag. Avoid using any cleaning solutions or solvents. If the LCD screen is dusty or dirty, lightly wipe the screen with a damp rag. Avoid using pressure when wiping to avoid scratching the LCD screen.

4.6.3.4. Ensure the protective boot on the back of the instrument is always covering the data port when not being used to avoid getting dirt into the port – **Figure 8**.



Figure 8

4.6.3.5. Always store the gauge in its protective case when not in use and in a secured locked bin on the service vehicle. Do not keep or leave the gauge unattended in the cab of the service vehicle.

4.7. Calibration/Repairs of the Equipment:

4.7.1. The calibration cycle will be set by the Metrology Lab prior to deployment of the gauge. The gauge shall be calibrated annually (12 months), regardless if the gauge is used or not. When calibration is due, prepared the gauge for delivery via Company Mail, shipped in the protective case and with both pieces of the quick-connect included.

4.7.2. Tag the case with a standard blank Manila or White tag that includes the Employee’s name, base code (if applicable) and base location. Ensure the case closing clamps are fully closed to prevent the case from opening during transport.

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Note: The gauge can be hand-delivered to the **Metrology Lab** for calibration. Be sure to seek prior approval from Supervision.

4.7.3. Ship the gauge kit to the **Pico Rivera Metrology Lab** at **ML: SC721A**. The Metrology Lab will return-ship via Company Mail back to the base location noted on the tag.

4.8. **Equipment Purchasing:**

4.8.1. For equipment needs, contact the **Pico Rivera Metrology Lab** at **(562) 806-4373**.

4.9. **Accessories:**

4.9.1. **CST/IST Gauge Stack:**

Note: Items used to construct the Gauge Stack are purchased through Direct-Purchase from an outside source – see section 4.9.1.2 below.

4.9.1.1. The Gauge Stack must be assembled in a specific configuration to allow the pressure to be purged from the gauge after use and before disconnecting the gauge from the gauge stack, using the approved fittings noted – **Figure 9**.



A	Quick-Connect Body-Female	QC-TH216-303
B	HP Nipple (2)	GNL-4N—2.0-S
C	HP Tee	GTB-4N-S316
D	Plug Valve	V23A-F-4N-BK

Figure 9

4.9.1.2. To Purchase a Gauge Stack Kit or single fittings, contact **A-Best Industrial:**

Tim Marquez – A-Best Industrial

1911 N. Gaffey Street – Suite D
San Pedro, CA 90731
Office: (310) 833-3353
Email: sales@abesttube.com

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4.9.2. **ETR – 2 PSIG Gauge Stack:**

Note: Items used to construct the Gauge Stack are stock coded items through local storerooms.

4.9.2.1. The 2-PSIG Gauge Stack must be constructed using the approved fittings – **Figure 10.**



Figure 10

2 PSIG Gauge Stack Parts List

Item	Description	Stock Code
A	Quick Release	Provided with Kit
B	1/4" Tee	N501524
C	1/4" Valve – (1/4" Male to 1/4" Female)	Direct-Purchase
D	Orifice - Short	N205920
F	Size 1 Meter Spud	N357298
G	Size 1 Meter Ring	N356030
H	1/4" x 3/4" Steel Bushing	N522130



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Note: Letters **F, G, and H** above can be substituted with the correlating fitting sizes to accommodate whatever meter size is being set at the facility.

5. EXCEPTION PROCEDURE

Exception Procedures are not applicable to Company Operations Standards for tools and equipment as any deviation from the manufacture recommended instructions can damage the tool or equipment and result in personal injury to the user.

6. RECORDS

Not Applicable

7. APPENDICES

Not Applicable



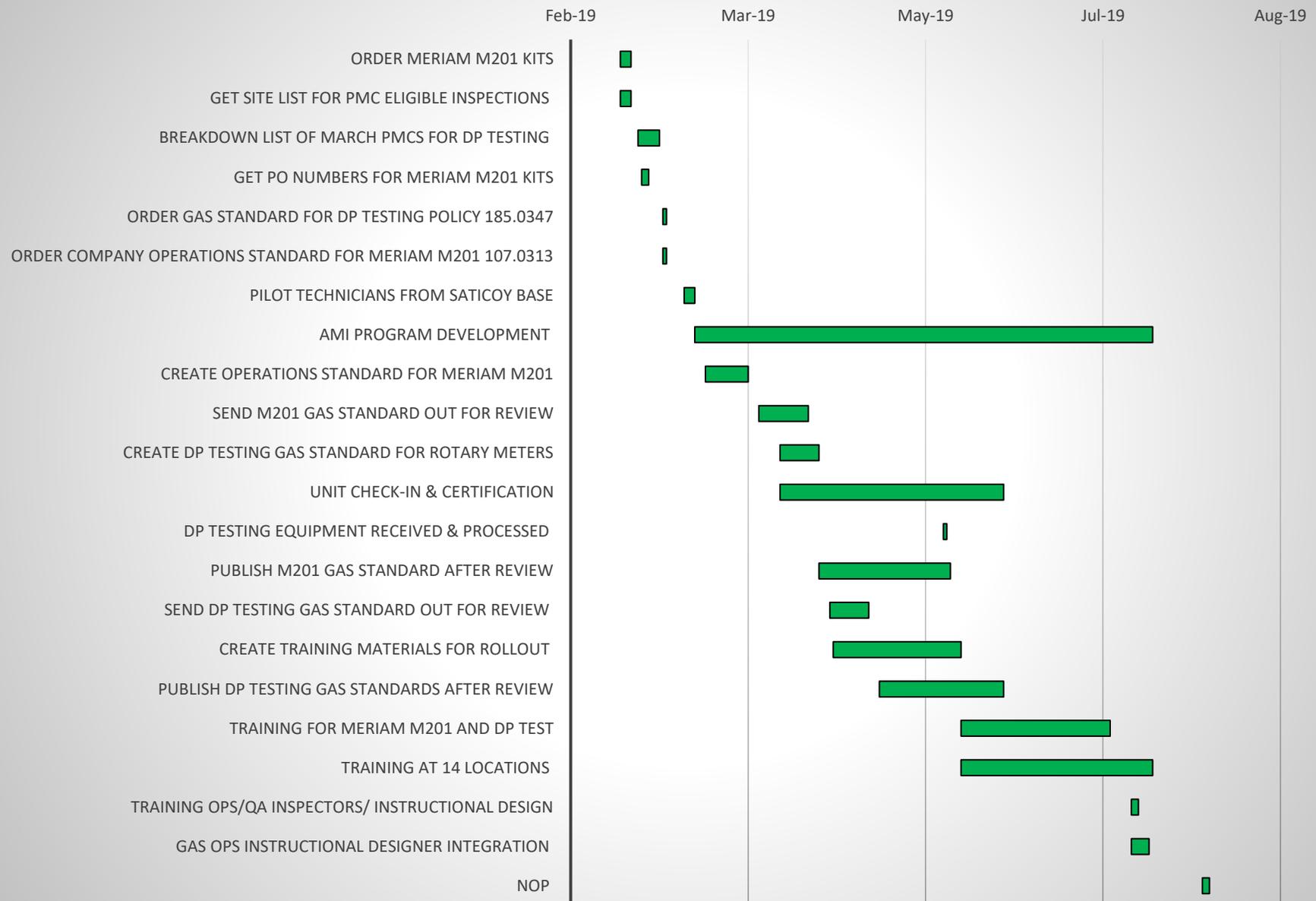
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Part of Non-O&M Parts 191-193 Plan	No
Non-O&M 49 CFR Codes & Impacted Sections of Document	
Part of Distribution IMP (DIMP)	No
Part of Transmission IMP (TIMP)	No
Part of Storage IMP (SIMP)	No
Impacts GO112F	No
GO112F Codes & Impacted Sections of Document	
Impacts Underground Gas Storage Projects (DOGGR)	No
14 CCR Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
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Chapter 23 - Differential Pressure (DP) Testing





Recognize the potential for increased safety, significant productivity gains and time-savings with the new RMLD-CS. Remote detection allows utility services personnel and first responders to quickly scan an area for suspected gas leaks at a safe distance.

The HEATH Remote Methane Leak Detector - Complete Solution (RMLD-CS) is a highly advanced technology, capable of detecting methane leaks from a remote distance utilizing the same TDLAS (tunable diode laser absorption spectroscopy) technology as the current RMLD. This instrument eliminates the separate receiver and transceiver, combining them into one hand-held instrument that is lightweight, portable and field rugged. The RMLD-CS makes it possible to detect leaks without having to walk the full length of the pipe line, thus creating safer surveys in areas that may be difficult to reach such as busy roadways, yards with dogs, fenced off areas and other hard to access places. It operates under a variety of field conditions including a wide temperature range, light rain and fog. Its rugged design will stand up to normal field use and operating conditions and its sensitivity or range is not affected by reasonable amounts of dust on the instrument's window.

The RMLD-CS includes many new features including:

- ➔ Rechargeable and replaceable battery
- ➔ Dual battery charger
- ➔ Mobile App support
- ➔ Ergonomic housing
- ➔ Lightweight
- ➔ Graphical user interface
- ➔ Internal data logging
- ➔ WiFi
- ➔ GPS
- ➔ Bluetooth BLE
- ➔ Color camera
- ➔ Color display



9030 Monroe Road, Houston, TX 77061
www.heathus.com PH:713.844.1300

SPECIFICATIONS

Detection Method	Tunable Diode Laser Absorption Spectroscopy (TDLAS)
Measurement Range	0 to 99,999 ppm-m
Sensitivity	5 ppm-m at distances from 0 to 50 ft (15m)
Detection Distance	100ft (30m) nominal. Actual distance may vary due to background type and conditions.
Beam Size	Conical in shape with a 22" diameter at 100 ft (55 cm at 30 m)
Detection Alarms Modes	Digital Methane Detection(DMD): Audible tone relative to concentration when detection threshold exceeded Adjustable Detection Alarm Level 1 to 999 Real Time(RT): Continuous audio chirp relative to concentration.
System Fault Warning	Unique audible pitch and indication on the display.
Self Test & Calibration	Built-in Self Test and Calibration function verifies operation and adjusts laser wavelength for maximum sensitivity. Calibration results are stored on the device and can be downloaded by the user. Test gas cell integrated within carrying case.
Compliance	EMC (EN61000-6-2, EN6100-6-4)
Intrinsic Safety	Pending
Laser Eye Safety	IR Laser: Class I, Spotter : Class IIIa Do not stare into beam or view directly with optical instrument.
Communications	Bluetooth 4.2 BLE, WiFi, USB Dual Mode
Display	3.5" LCD
Operating Temperature	0° to +122° F (-17° to 50° C)
Humidity	5 to 95% RH, non-condensing
Enclosure (Inst.)	IP54 (Water Splash and Dust Resistant)
Instrument Weight	≈ 3 lbs.
Battery	Removable, rechargeable, Li ion battery pack, 12-15 VDC
Battery Run Time	8 hours at 32° F
Battery Charging	External, in-line, 110-240 Vac, 50/60 hertz, international
Charge Time, Maximum	2 - 3 hours
Charging Indicator	Integrated into dual battery charger
Survey Vest	Designed for Class 2, with multiple pockets, adjust-ability for both sides.

ORDERING DETAILS



RMLD-CS - HPN 105301
Includes carry strap, case, battery charger, power supply, USB cable, one battery pack, gas calibration test cell.



Battery Pack - HPN 105384
Li-Ion replacement battery.



Battery Charger - HPN 105358
Charges two batteries at a time.



Survey Vest - HPN 105357 (M/L)
Survey Vest - HPN 105406 (L/XXL)
Class 2, multiple pockets for equipment, maps or water pack.

Heath Consultants Incorporated operates under a continual product improvement program and reserves the right to make improvements and/or changes without prior notification.



Your Safety...Our Commitment

9030 Monroe Road, Houston, TX 77061
www.heathus.com PH:713.844.1300

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PURPOSE Measurement, Regulation & Control (MRC) with Region consultation determines the frequency of inspections of measurement and regulation equipment based on regulatory requirements, equipment performance and problems reported. Published inspections are minimum requirements. Regions have the option of performing more frequent inspections where conditions indicate the need.

1. POLICY AND SCOPE

1.1. To maintain the integrity of all measurement, regulation equipment, records and schedules for associated equipment with regulator stations and power generating plants.

2. RESPONSIBILITIES & QUALIFICATIONS

2.1. **Region field personnel** perform inspections and tests on regulator station and power generating plant equipment to ensure that the station/plant is in good mechanical condition, set to function at the correct pressure, and is properly installed and protected from dirt, liquids, erosion, or other adverse conditions affecting operation.

2.2. **Regions** are responsible for conducting on-the-job training and self-audit programs to ensure compliance with this Standard.

3. DEFINITIONS

3.1. SAP – System, Applications & Products in data processing

3.2. SAP-PM – Plant Maintenance (SAP-PM is the Plant Maintenance module for SAP application)

3.3. Click Schedule – application used by the Area Resource & Scheduling Organization to plan, schedule and assign work to field crews.

3.4. Click Mobile – (Field mobile application software) – this is the approved Company software that is loaded onto each M&R field technician’s Mobile Data Terminal

3.5. MAXIMO – The computerized maintenance management system used by SoCalGas to assist with planning, scheduling, and documentation of maintenance work on transmission and underground storage piping and equipment.

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4. PROCEDURE

- 4.1. **Region field personnel** report dirt, liquids, erosion and other adverse conditions to supervision within one workday. Supervision to initiate installation of a screen or filter. See [GS 184.0035](#), *Regulator Station Design and Planning*.
- 4.2. Records documenting new facility installation, field inspections and maintenance for each regulator and power generating plant facility, are maintained by the responsible **Distribution/Transmission Regions**
- 4.3. **Region Technical Services** determines once each year if the regulator station / power generating plant has adequate capacity and is operating reliably for its service area.
- 4.4. See web link <http://edsts-mdt.sempra.com/Index.htm> "Regulator Equipment Codes" (Option 3) for a complete listing of valid Regulators with minimum inspection intervals and equipment codes.
- 4.5. **Regions** schedule more frequent inspections as conditions warrant.
 - 4.5.1. **Region field technician's** complete inspection steps for the following:
 - 4.5.2. Regulator station requirements listed in new **Appendix A** of this Standard.
 - 4.5.3. Piston operated valve regulator requirements listed in new **Appendix B** of this Standard.
 - 4.5.4. Power generating plant requirements listed in new **Appendix C** of this Standard.
- 4.6. Each pressure limiting station, relief device (except rupture discs), signaling device and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is:
 - 4.6.1. In good mechanical condition;
 - 4.6.2. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;
 - 4.6.3. Except as provided in paragraph (4.7), set to control or relieve at the correct pressure consistent with the pressure limits of §192.201(a); and

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- 4.6.4. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.
- 4.6.5. For steel pipelines whose MAOP is determined under §192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS	MAOP plus 4 percent.
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

- 4.7. Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §192.739(b), the capacity must be consistent with the pressure limits of §192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.
 - 4.8. If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.
 - 4.9. If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (4.7) of this section.
5. INSPECTIONS

Inspection Scheduling

- 5.1. The SAP-PM (Plant Maintenance) application will create preventive inspection orders for regulators, valves, vaults and mainline filter equipment in regulator

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stations and power plants. The supervisor of region measurement functions is responsible for assuring all equipment is accounted for and inspected on time.

- 5.2. Regulator stations and power generating plants must be inspected at least once each calendar year. Inspections, including remedial work, are completed during the base inspection (anniversary) month, or within the “grace” period (defined as **one month** following the base inspection month for **customers** and **3 months** following the base inspection month for **District Regulator Stations**). Exceptions are:

- 5.2.1. **Customer** inspections with a base month for January must be completed in January or February.
- 5.2.2. **District Regulator Station** inspections with a base month for January must be completed in January, February, March or April.
- 5.2.3. December base month inspections must be completed in December.
- 5.2.4. Bi-annual inspections must be completed within their base month, and again during their 6-month anniversary (no “grace period”).
- 5.2.5. Quarterly inspections must be completed within their base month, and again during each 3-month anniversary (no “grace period”).

Note: Supervisor approval required if a Base Month is to be changed from original. Contact MRC staff for assistance.

6. INSPECTING A REGULATOR STATION THAT IS SHUT-IN, DE-ENERGIZED, LOCK-OUT TAG OUT DUE TO PROJECT WORK OR OTHER CIRCUMSTANCES.
- 6.1. Use natural gas bottle(s) also known as Meter Change Device (MCD) to temporarily supply inlet pressure to stations when it’s reasonable and safe to do so.
 - 6.2. Meter Change Device (MCD) is used when the required inlet pressure to regulator station isn’t available. A typical CNG cylinder holds approximately 348 cubic feet of gas.
 - 6.3. Consult with local supervision prior to using alternate source of supply pressures and/or when shut in station is unable to be inspected.
 - 6.4. See section 7 of this gas standard for additional instructions.

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7. COMPANY ASSETS THAT ARE UNABLE TO BE INSPECTED WITHIN COMPLIANCE WINDOW.

If upon arrival the asset is unable to be inspected due to; project work, de-energized, lock-out tag out, and or shut-in due to abnormal operating conditions or compromised piping or equipment, responsible personnel will take the following steps:

- 7.1. Place Work Order in ‘Action Required’ (Distribution) or “follow up” work order (Transmission) and notify supervisor immediately.
- 7.2. Supervisor will monitor the work order compliance dates and asset status. If assessment determines that asset inspection cannot be completed by the scheduled base month inspection date plus 3 month grace period, supervisor will notify the Region Asset Maintenance and Inspection Manager.
- 7.3. Region supervisor is responsible for notifying the Maximo Support Team and M&R Process and Compliance Support when base month change is required.
- 7.4. When the base month inspection plus 3 month grace period cannot be met, the regulator station base inspection month will be modified in SAP and Maximo to the month when the regulator station is placed back in service. A documented inspection is required prior to placing the station back in service.
- 7.5. If a regulator station remains shut-in and uninspected for over 1 year, an internal inspection is required before placing the station back in service.
- 7.6. Once station has been reinstated after 1 year or more “out of service” condition, perform follow up external inspection within two weeks of reactivation.
- 7.7. A temporary ID drawing is issued for unattended shut-in stations due to ; project work, de-energized and lock-out tag out.
- 7.8. Temporary drawings can be hand drawn and must show current inlet and outlet valve positions (Open or Closed).
- 7.9. Temporary “*Do Not Operate*” tags are placed on valves that are not in their normal operating position.
- 7.10. Temporary drawings/signage is removed once station is returned to normal operating status and standard drawings are reinstated.
- 7.11. Electronic pressure monitors (EPM) at stations that have been shut-in will be temporarily deactivate when the normal inlet pressure supply to EPM is no longer available. Notify region engineering when deactivating EPM. Region engineering

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must find alternate location for EPM or evaluate if pressure district can operate without the EPM.

8. SAP-PM Self-Audit

8.1. Supervisors and Leads will be able to verify all outstanding and completed orders through SAP-PM. SAP-PM will create and Click Schedule will issue work orders.

8.1.1. NOTE: With the roll out of OpEx, clerks, leads and supervisors will run daily reports against open notifications and orders in SAP for suspect non-compliance work. These reports are available via standard SAP or through SAP-BW. When Click Release 8 is rolled out, an exception report for preventive orders due and any orders near due date that will go into “*Jeopardy*” will be developed to allow the appropriate Supervisor to take immediate action. Reports should be run daily to ensure strict adherence to inspection intervals for compliance to CPUC and DOT rules and regulations.

9. Expansible Element and Diaphragm

9.1. SAP-PM determines the interval, creates the preventive work order and **Click Schedule issues the order to perform** internal-parts-replacement (IPR) inspections for diaphragm or expansible elements at varying internals (depending on type and manufacturer) not to exceed fifteen (15) years.

9.2. Replace pilot diaphragms and valve seats etc., with associated mainline regulator IPR inspections.

NOTE: District Regulator Stations - Internally inspect expansible element regulators every 2 years if used as a monitor with pilot that bleeds either to atmosphere or into another system. The SAP-PM maintenance plan must be updated manually for each regulator meeting the above criteria.

Customer MSA’s - Externally inspect expansible element regulators every 12 months if used as a monitor with pilot that bleeds either to atmosphere or into another system. The SAP-PM maintenance plan must be updated manually for each regulator meeting the above criteria.

Contact MRC – Measurement Technologies to request updates to each regulator maintenance plan meeting above criteria.

10. DISTRICT REGULATOR STATION (DRS) SPECIAL INSPECTIONS

Special inspections require:

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- Inspection of all regulators.
- Operation test of piston operated valves.
- Inspection of all mainline filters, pilot filters and screens/strainers.
- Special winter inspections. (See item 8.2, of this section)

NOTE: DRS equipped with a mainline filter require only an external regulator inspection if filter inspection is found free of debris and liquids and the elements are intact.

- 10.1. Perform a special internal inspection on each regulator at regulator stations whenever there is a reason to suspect foreign materials/substance (wet or dry) in the gas stream.
- Enter appropriate condition code(s) on field orders.
- 10.2. Also, perform a special internal inspection on each regulator within 5 working days of significant gas flow or overpressure, and a special winter inspection is performed no later than December 31. Reference **Appendix A, Regulator Station Inspection Requirements, Section 4.18, Inspect Mainline Filter and Strainer/Screen** of this GS if internal or external inspection is required.

The following sub points listed are reasons for performing a special internal inspection within 5 working days.

NOTE: Gas Flow calculations can be used in lieu of special internal inspection as long as the calculations are less than Winter Peak Loads determined by the **Region Engineer's** calculations, making an internal inspection optional.

- 10.2.1. Construction of new line or piping upstream of the regulator.
- 10.2.2. A significant change in station's normal operation load where flow exceeded winter flow capacities.
- 10.2.3. A significant change in supply system velocity.
- 10.2.4. A significant change in supply system flow pattern.
- 10.2.5. Activation of a new or rebuilt regulator station.
- 10.2.6. External test results indicate a problem.

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10.2.7. A main break 4 inch and larger diameter pipe (12 square inches or greater opening) upstream or downstream of DRS. (See [GS 184.0281](#), *Filtration Requirements for Regulator Stations*, Table A, Note 3)

10.2.8. Erosion is found during inspection.

- Notify your supervisor within one workday and complete, [Form 5330](#), *Operating and Maintenance Order (OMO)*, when this condition is found for the applicable corrective action required.
- Enter appropriate code (38 erosion) on field order and severity of condition with code major (71) for extreme condition and code 39 (regulator with immediate HIGH lockup) or minor (70) less severe conditions and code 39 (regulator with slow creeping HIGH lockup).

11. CAPACITY CHECKS

11.1. Region Planning is responsible to determine:

11.2. The adequate capacities of district regulator stations using **Forms 3998**, *Annual Record of Pressures in Distribution Districts*.

11.3. The adequate capacities of pressure relieving devices. See [Form 4028](#), *Annual Review of Relief Valve Capacities*. Special capacity checks are required prior to:

- Increasing inlet pressure to supply regulators.
- Reducing the Maximum Allowable Operating Pressure (MAOP) of area served.
- Increasing capacity of pipelines leading to the regulator.
- Increasing size of regulator or regulator orifice.
- Small relief valves (less than one inch) used as signaling devices recommended by **MRC** for pilot regulator overpressure protection are exempt from this review.

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12. INSPECTION OF SURROUNDING AREA

- 12.1. The **supervisor**, his designate, **Lead** or **M&R Tech** responsible for M&R field functions checks the area surrounding the station every unscheduled or scheduled inspection when a relief valve provides main regulator overpressure protection. The check is made to determine if blowing gas is safe or appropriate with consideration given to foot and vehicular traffic, buildings, power lines, etc.
- 12.2. Use [Form 4683](#), *MARGO*, to record the field check results. If conditions indicate that relief protection is no longer desirable, route [Form 4683](#) to **Region Planning Department**. File form for last two inspections with [Form 4028](#), *Annual Review of Relief Valve Capacities*.

13. OPERATOR QUALIFICATION COVERED TASKS

(See [GS 167.0100](#), *Operator Qualification Program*, Appendix A, *Covered Task List*)

- **Task 2.2** – 49 CFR 192.461 – Properly applying external protective coatings for corrosion control
- **Task 2.13** – 49 CFR 192.481 – Monitoring for atmospheric corrosion
- **Task 2.15** – 49 CFR 192.487 – Recognizing general and localized corrosion, taking action: Distribution
- **Task 3.1** – 49 CFR 192.503(d) – Leak Testing non-welded joints
- **Task 7.1** – 49 CFR 192.629 – Purging Pipeline
- **Task 13.1** – 49 CFR 192.739 – Inspection/testing of pressure limiting and regulating stations and devices
- **Task 15.1** – 49 CFR 192.743 – Inspection/testing of relief devices
- **Task 16.3** – 49 CFR 192.747 – Inspection operating, and maintaining distribution system valves
- **Task 17.1** – 49 CFR 192.749 – Inspecting/maintaining vaults

14. EXCEPTION PROCEDURE

(See [GS 182.0004](#), *Exception Procedure for Company Operations Standards*)

[This section should remain and not be removed unless another applicable exception procedure is included in the standard.]

- 14.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.

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- 14.2. An exception from a standard shall not be allowed unless [GS 182.0004](#), *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

15. RECORDS

Forms/Reporting and Retention

- 15.1. Completed field order results including “preventive” (scheduled) and “corrective” (unscheduled) inspections are entered into Click Mobile. For new facility installation data, enter information onto manual forms. Master facility (functional location) and equipment information is updated in SAP-PM.
- 15.1.1. Use Report Manager report B71615-01, Base Register Order-Cust MSA and report B71615-02, Base Register Order- Dist Reg, or [Form 4683](#), *Meter and Regulator General Order (MARGO)*, to record unscheduled inspection results new facility installations and unscheduled inspection results when Click Mobile is not available.
- 15.1.2. For “new business” or “new-to-M&R” installations, use [Form 4683](#) to report installation of all regulators, mainline filters, valves, vaults, shut-off devices and other similar equipment located at M&R facilities.
- 15.1.3. Access Click Mobile **Form 5600 “Equipment Change Out List”** and **select applicable equipment form** to report removal or replacement or additional installation of all regulators, mainline filters, valves, vaults, shut-off devices and other similar equipment located at existing **M&R facilities**.
- 15.1.4. **Field Technician** — Reviews, signs and forwards all field orders to the M&R Section Clerk within one **(1)** day of the field order completion date when Click Mobile is not available.
- 15.1.5. **M&R Clerk** — Enters any orders not entered into Click Mobile into SAP within three **(3)** working days of receipt, not to exceed five **(5)** work days of the field order completion date.
- 15.1.6. Forms Retention: See Records Retention Standards on Sempra Net, <http://home.sempranet.com/rm/> reference OPS-20-04 and OPS-20-06.

16. APPENDICES

- 16.1. **APPENDIX A: Regulator Station Inspection Requirement**

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- 16.2. **APPENDIX B:** Piston-Operated Valve Regulator Inspection Requirements
- 16.3. **APPENDIX C:** Power Generating Plant Inspection Requirements

APPENDIX A

REGULATOR STATION INSPECTION REQUIREMENT

Provide uniform guidelines when performing periodic and special inspections.

1. External Inspection (EXT)

Complete the following requirements, if applicable, during each scheduled external inspection.
2. VAULT INSPECTION

For detailed vault inspection requirements, reference Gas [Standard 223.0210](#) *Vault Maintenance and Inspection*.

Test vault with combustible gas indicator before entering. See [GS 166.0077](#), *Confined Space Operations* and See [GS 107.0284](#), *MSA ORION® Multigas Detector Unit*.

 - 2.1. Each vault housing pressure regulating and pressure limiting equipment and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, and during all unscheduled inspections to determine it is in good physical condition and adequately ventilated.
 - 2.2. Each vault cover must be inspected to assure that it does not present a hazard to public safety.
 - 2.3. All other vaults having volumetric internal content less than 200 cubic feet are inspected each time the MSA is inspected to assure public and employee safety.
3. CHECK STATION PIPING FOR ELECTRICITY
 - 3.1. Check station for electricity using a company approved AC. (alternating current) voltage detector, when required to make physical contact with the station. See [GS 185.0300](#), *MSA - Installing, Rebuilding and Inspections*, (Electricity in Meter Sets and Appendix A).
4. CHECK STATION CONDITION

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- 4.1. Remove debris and weeds from area. Clean thoroughly around vault lid to avoid springing lid when opening.
- 4.2. If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.
- 4.3. Check for and remove water in vault.
- 4.4. The ventilating equipment must also be inspected to determine that it is functioning properly.
- 4.5. Check station for proper installation of piping and control lines. Repair as needed.
- 4.6. Inspect condition of the following as appropriate and repair where necessary, or issue follow-up order to have work done.
 - Walls
 - Fencing
 - Buildings
 - Barricades
 - Vault Floor
 - Vent stacks
 - Vault covers
 - Gauge houses
 - Piping supports
 - Overall Vault Condition
 - Strain on piping due to ground settlement.
 - Signage consistent with the requirements of §192.707(c, d)
- 4.7. Check station for existence of Intersection Drawing (I.D.) and verify accuracy of regulators, valves and related components. **Valves which are normally closed must be labeled ‘CLOSED’ on the station ID drawing.** If the station is incorrect, submit correction to Supervisor within one week of findings.
- 4.8. See [GS 184.0195](#), *Regulator Control Piping and Settings*, for additional instructions.
- 4.9. Check and record inlet and outlet pressures and ensure they are within MAOP/Authorized tolerances.

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- 4.10. Monitor district pressure downstream from all valves throughout inspection and maintenance activities, and re-check pressure prior to departure.
- 4.11. Inspect Stop Valves.
 - 4.11.1. Lubricate valves requiring lubrication, and when found hard to operate. Valves requiring lubrication do not necessarily need to be lubricated during each inspection. This includes all plug valves and the Rockwell Hypersphere™ (trunnion mounted) Valve and Grove Ball Valve (Model B-5) do not require lubrication for normal operation. See [GS 184.0285](#), *Lubricate Plug Valves* and [GS 184.16](#), *Valve Inspection and Maintenance — Distribution*.
 - 4.11.2. Use two strokes of handgun or four pulses of pneumatic gun per inch of valve size.

NOTE: If valve will not accept sealant (an indication that lubricant grooves are plugged), flush valve in accordance with [GS 184.0290](#), *Flushing Plug Valves*.

- 4.11.3. Use one stick of sealant when installed with a lubricant screw. Verify that use of the screw has not changed the valve position.
- 4.11.4. Install a proper size button head lubricant fitting if valve is not so equipped. Install an extension high head with lubricant tube if the valve's depth will not permit the lubricating hose coupler to be attached to the button head. High head devices can be installed without excavating. Each cased plug valve should be left (install adapter if required) so as to permit the use of the standard 2-5/32" socket on the valve wrench. If the use of a special adapter is required, leave the adapter in the daxing, and note on the valve inspection order.
- 4.11.5. If the valve is in a casing, test valve casing for leaking gas. If gas is detected and leak cannot be repaired by tightening the packing gland or lubricating the valve, complete the inspection and issue a leak order, [Form 5330](#), *Operating and Maintenance Order (OMO)*, to repair the leak. For Click Mobile users' note that additional follow-up work is needed in the remarks section on form 5110 District Regulator Station – Inspection.
- 4.11.6. Verify that valve tag is in place and identification number corresponds with the number on valve inspection order. If there is a discrepancy, immediately resolve the problem with the responsible **Supervisor**.

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4.11.7. Hard to operate or inoperable valves must be repaired or replaced within the inspection and grace period for the **district regulator station**.
See [GS 184.16](#), *Valve Inspection and Maintenance— Distribution*.

4.12. Check Regulator Operating Pressure

4.12.1. Operate and check all regulator settings using approved pressure standards that are in good working condition and possess a current calibration date.
See [GS 107.0310](#), *Approved Measurement Standards - Use, Maintenance and Calibration*.

4.12.2. Use manual bypass if needed. Compare actual settings with those listed on order, update as needed, and verify information on regulator identification tag is correct. See [GS 184.0195](#), *Regulator Control Piping and Settings*

4.13. Check Regulator Lockup

4.13.1. Check all regulators, relief valves, and signaling devices for lockup and record lock-up difference.

- Enter lock-up difference for each spring-loaded regulator.
- If regulator is pilot loaded, post lock-up difference to associated pilot.
- For relief valves, shut-offs, and signaling devices enter difference between release point (setting) and closure/seal point.

4.13.2. Compare pressures with previous lock-up difference.

4.13.3. Metal-seated regulators do not require tight lockup, record-closing pressure in “**Remarks**” section of **Click Mobile Form 5110 “DRS General Inspection”**. Verify mainline regulator code as having “metal” seats.
See [GS 185.0555](#), *Regulator Lockup Tests*.

4.13.4. Regulator setting plus lockup difference must not exceed MAOP limits. See [GS 185.0287](#), *Over-Pressure / Under-Pressure Protection – Maintenance, Installation and Setting, Section 11*.

4.14. Check for Diaphragm Leakage

4.14.1. Place soap bubble over regulator vent.

4.14.2. Test for leakage at diaphragm chamber lip.

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- 4.15. Check Control Piping
 - 4.15.1. Drain all traps in control piping. See [GS 104.0070](#), *Field Sampling Guidelines for PCBs*.
 - 4.15.2. Clear any foreign objects from station piping or equipment.
 - 4.15.3. Verify control piping is secure, protected and not installed in lower half of horizontal piping.
- 4.16. Check Pilot and Instrument Filter
 - 4.16.1. Operate filter inlet sump blow off valve or make a visual internal inspection of pilot and instrument filters for cleanliness.
- 4.17. Check Relief Valves / Signaling Device
 - 4.17.1. Check caps on all relief valves to make sure they are loose enough to open readily if relief valve operates.
 - 4.17.2. Operate all relief valves and backpressure regulators used as relief valves and shutoff valves (except rupture disc type) to determine proper operation.
 - 4.17.3. Test relief valve for leakage after operating test. Place soap bubble over outlet of relief valve, or test atmosphere in stack with gas indicator.
 - 4.17.4. Verify information on identification tag is correct.
 - 4.17.5. Check Signaling Device for operation.
- 4.18. Inspect Mainline Filter and Strainer/Screen
 - Filters:
 - 4.18.1. If a mainline filter does not have a filter-monitoring device, then perform internal inspection

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- 4.18.2. If the mainline dry gas filter has a filter-monitoring device and monitor indicator **exceeds** the pre-established **two-pound** differential limit, then an internal inspection is required. Some special filters may require differential pressures that exceed 2 psig. Establish unique requirements for those locations.
- 4.18.3. If a special inspection was performed on the filter prior to the scheduled inspection and dust/debris was found, then an internal filter inspection is required.
- 4.19. Screens and Strainers
 - 4.19.1. Mainline strainers/screens require, at a minimum, blowing the purge valve to determine if any dust, dirt, or debris is present.
 - 4.19.2. If a substantial amount of dust, dirt, or debris is found, (one 8 ounce cup or more), during and after blowing down the purge valve, an internal inspection is required to, (1) remove any additional material, (2) to verify that the strainer/screen remains structurally sound and (3) determine if a full sized filter is warranted.
 - 4.19.3. On a newly installed mainline strainer/screen an internal inspection is required during its first scheduled inspection.
- 4.20. Check Deodorizer and Charcoal Filter
 - 4.20.1. Make a "sniff" sampling of deodorizer or filter. Replace deodorizing material if odor of gas is evident at bleed outlet.
- 4.21. Check Pressure Recording Gauge

Inspect pressure-recording gauge (mechanical or Electronic Pressure Recorder). See [GS 185.0340](#), *Pressure Recording Gauges-Installation, Inspection, Maintenance & Calibration*.
- 4.22. Check Valve Position
 - 4.22.1. Check stop valve under each relief valve to verify it is open and locked.
 - 4.22.2. Check control line valves for proper position. For installations not in a vault or fenced enclosure, remove the valve handles or padlock valve.
 - 4.22.3. Verify correct position of all valves inside station and shutoff valves outside station.

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4.22.4. Lubricate valves requiring lubrication for normal operation. See [GS 184.16](#), *Valve Inspection and Maintenance — Distribution*.

4.23. Check for Leaks

4.23.1. Before opening a closed vault, test for the presence of gas at edges or openings with approved company leak detection equipment. If no presence of gas is detected, carefully open the vault. If the presence of gas is detected, determine if special precautions are required before opening and ventilating the space. See [GS 166.0077](#) Confined Space Operations

4.23.2. Prior to removing the lid to any valve casing, test for the presence of gas in the casing using approved company leak detection equipment. After manipulating a valve, replace the lid and again check for leaks. See [GS 184.16](#) Valve Inspection and Maintenance - Distribution

[4.23.3. Soap test all connections during inspection and leave facility free of leaks.](#)

4.24. Corrosion

Inspect for coating deterioration on all new and existing metallic gas piping, except stainless, installed above ground or piping exposed to atmosphere in a vault or curb meter box, clean and recoat as necessary with an approved coating to prevent corrosion and deterioration. See [GS 186.0002](#), *Design and Application of Cathodic Protection*, paragraph 2.1.5.

4.25. Paint Station

Paint all new and existing metallic gas piping, except stainless, installed above ground or piping exposed to atmosphere in a vault or curb meter box with an approved paint as needed to prevent corrosion and deterioration. See [GS 186.0002](#), *Design and Application of Cathodic Protection*, paragraph 2.1.3.

5. INTERNAL INSPECTIONS (INT)

Internal inspections are performed when station maintenance history, operating conditions, or the external inspection results indicate worn parts, damage or debris in the regulator. Any disassembly with or without parts replacement, short of a complete Internal with Parts Replacement Inspection is considered an Internal inspection.

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6. INTERNAL WITH PARTS REPLACEMENT INSPECTIONS (IPR)

Internal with parts replacement inspections include all external requirements plus the following:

- 6.1. Replace soft parts (O-rings, disc, etc.) on inner valves. Replace expansible elements.
- 6.2. Replace diaphragms (leather or synthetic) in mainline regulators.
- 6.3. Replace or rebuild pilot regulators using new soft parts.
- 6.4. Replace filter elements in filters supplying pilot regulators and instruments.
- 6.5. Internal inspection and soft parts replacement is not required for the valve portion of a motor valve operated ball valve. Inspect and replace parts if inspection indicates a need.

7. SPECIAL INSPECTION

- 7.1. See **Section 10** District Regulator Stations (DRS), Special Inspections of this Standard.
- 7.2. See **Appendix A**, Section 4.18. Inspection Mainline Filter and Strainer/Screen applicable

NOTE: If there is no mainline filter, disassemble and inspect the valve portion of all mainline regulators. (INT)

8. MALFUNCTION OF REGULATORS AND RELATED EQUIPMENT

- 8.1. Check regulators and related equipment to determine and record cause of malfunction, such as downstream pressure outside of normal tolerance, erratic operation or failure to control. Use appropriate system condition and activity codes from the Click Mobile pick list Form 5460 "Regulation Inspection" and explain additional comments in Remarks section on Click Mobile **Form 5010** (MSA) or Click Mobile **Form 5110** (DRS) order.
- 8.2. Take corrective action to minimize possibility of a recurrence. Record appropriate activity codes and additional actions taken in Remarks section.

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APPENDIX B

PISTON-OPERATED VALVE REGULATOR INSPECTION REQUIREMENTS

Provide guidelines while performing the following requirements for periodic inspections at district regulator stations and customer large meter sets.

9. External Inspection
 - 9.1. Put installation on bypass if necessary. Stand clear of actuator movement at all times.
 - 9.2. Shut off supply through piston-operated valve by closing its upstream or downstream mainline valve.
 - 9.3. Check operation of controllers, air control or relay valves, positioners, other instruments and valve actuators. If controller has reset action, check to see that it is working properly.
 - 9.4. Check and verify settings, and check and record lock-up differences of all control line devices (as applicable) and regulators associated with the piston-operated valve regulator. Verify equipment is tagged correctly.

NOTE: Lock-up difference for the piston-operated valve regulator is recorded as difference between controller (pilot) setting, and minimum induced closing pressure, required to fully close the main valve.

- 9.5. Three-Point Check on BPE regulators, perform the following:
 - 9.5.1. Ball Valve Check
 - Check mainline regulator for lock-up. In addition, check ball valve condition by blowing down body cavity while in the closed position. This check determines condition of both inner and outer seat rings.
 - If valve fails to shut down completely, lubricate valve per [GS 184.16, Valve Inspection and Maintenance — Distribution](#).

NOTE: All Grove ball valves are designed not to require sealant. However, our Company's experience has identified the need to lubricate these valves under certain conditions. When lubrication is necessary use #47 Mobil lubricant.

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- If complete blow-down is not achieved by lubrication, determine which seat ring is bad by distinguishing whether the blow-by is created from the inlet or outlet pressure. Leakage due to erosion is a greater possibility when regulator is under throttling conditions rather than when as an on-off device.

NOTE: Notify **Technical Services** to develop a plan for valve repairs.

9.5.2. Pneumatic Cylinder Leak Test

Operate valve actuator several times to flex the piston seals. Check for piston seal blow-by. This is done by venting piston side without the pressure and placing a soap bubble on vented fitting. Check both sides of piston using this method. If the leak test indicates evidence of leakage, complete inspection and notify your Measurement Supervisor.

9.5.3. Cylinder Rod Linkage Check ("Lost Motion")

Operate valve actuator to inspect regulator for lost motion. When this is done measure the travel indicator motion between cylinder movement and the start of ball valve rotation. This travel should be approximately 1/8-inch. Travel exceeding 1/4-inch is excessive and could affect control accuracy. Contact your Measurement Supervisor when this condition is discovered.

NOTE: A 10-to-20-psig signal should be used to operate actuator without moving ball when checking for lost motion

- 9.6. Operate all other valve actuators several times to flex the piston seals. It is the number of reversals of travel that is important.
- 9.7. Lubricate valve. If Grove ball valve, refer to item I.5.1 (a) Ball Valve Check.
- 9.8. Lubricate Ledeen valve actuators with automotive chassis grease.
- 9.9. Lubricate positioner linkage on valve regulators. Include pulleys on Foxboro's and ball joints on Baileys. Use Lubriplate, **M&S Code N453055**.
- 9.10. Lubricate Ledeen Spanseal positioner by turning lubrication fitting one full turn. Use Dow Corning #4 compound - special purchase item from Ledeen.
- 9.11. Check and report all other associated regulators and pneumatic equipment for lock-up and correct operation, i.e., positioners, controllers, no bleed pilots and pneumatic control valves.

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- 9.12. Return equipment to normal operation. Verify that all valves, regulators, controllers set points, reset knobs, etc. are in correct position.
10. INTERNAL (VISUAL) INSPECTIONS
- Internal inspections include all external inspection requirements plus the following:
- 10.1. Check oil level in body and oil dampening loop where applicable on plug and ball valve actuators. Oil level in body should be down a little and dampening loop should be full. Use SAE 50 or non-detergent motor oil 40 in body and rotary meter oil (Code 45-7800) in dampening loop.
 - 10.2. Clean and lubricate the piston rod and rollers on operators that do not have an oil bath. Use Lubriplate, **M&S Code N453055**.
 - 10.3. Check valves in controllers, positioners and other pneumatic control valves. Do not lubricate.
 - 10.4. Check that valve positioner intake and exhaust screens are not plugged with foreign material.
 - 10.5. Inspect all filters including built-in filters in Fisher 67F pilots and Bailey or Foxboro positioners. Clean or replace as necessary.
 - 10.6. Blow all control and instrument supply lines.
 - 10.7. Operate all valves equipped with valve actuators and record or verify the operating pressure. Reduce supply pressure to 24 psi and increase in 5-psi increments until valve operates. Compare with previous readings. If significant increase has occurred, lubricate or take other corrective action.
 - 10.8. BPE regulators do not require an internal inspection if the three-point checks are performed on schedule. See **Section 1.5** of Appendix B.
 - 10.9. Fisher HiBall and V-Ball regulators do not require an internal inspection of the ball valve, except as indicated by operation tests.
11. INTERNAL WITH PARTS REPLACEMENT (IPR)

NOTE: When indicated by operation tests, an Internal with Parts Replacement (**IPR**) is required.

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IPR inspections include all internal inspection requirements plus the following:

- 11.1. Internally inspect valve actuators, replacing soft parts as needed.
- 11.2. Replace controllers only when needed. Before inspecting or replacing the pressure controllers, **note proportional band, reset and set point.** (“As Found”) Condition.
- 11.3. Visually inspect and clean all Fisher 4100 controllers.
- 11.4. Replace malfunctioning internals of Bristol A/D's.
- 11.5. Bristol A/D units are cleaned and calibrated on test bench.
- 11.6. Replace and return controllers to Meter and Instrument Services for rebuilding.

NOTE: Adjust controllers in accordance with settings noted above in 3.2, “**as found**” condition.

- 11.7. Internally inspect and clean all positioners and pneumatically operated control valves. Leave all settings the same as before disassembly.
- 11.8. Rebuild or replace all pilot instrument supply and power gas regulators as needed. All setting should be left the same as before disassembly.
- 11.9. Replace all filter elements.
- 11.10. Lubricate all Bailey positioner supply and bypass valves with Bailey petcock lubricant - special purchase item from Bailey
- 11.11. Change grease in Bailey positioner gearboxes. Fill gearbox half full with Lubriplate, M&S Code 45-3055. Rotate gears to work grease into teeth.
- 11.12. BPE regulators **do not require IPR**, if the three-point checks are performed on schedule. See **Section 1.5** in Appendix B, *Three-point check for BPE Regulators*.
- 11.13. Fisher HiBall and V-Ball regulators do not require an IPR on the ball valve portion of the regulator, except as indicated by operations tests.

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APPENDIX C

POWER GENERATING PLANT INSPECTION REQUIREMENTS

1. General Requirements

- 1.1. Notify Plant Control Room before attempting any work on meter runs.
- 1.2. Provide means of maintaining service if meter run is taken out of service.
 - 1.2.1. Take no more than one run out of service at the same time.
 - 1.2.2. Operate manual bypass to carry a large portion of the load and let the standby run do the trimming if the facility has both manual bypass and automatic standby run. An operator must stay by the manual bypass valve and observe gauge during entire bypass operation.

2. OPERATING CHECK

Operating Check includes the steps listed in **Appendix A** of this Standard for an external regulator inspection plus the following:

- 2.1. Verify signal lights are functional, if installation is so equipped, while checking regulator operations.
- 2.2. Check operation of differential limit controllers to see that control valves operated at high and low set points. Introduce false differential to check. If control valve is open, block open before testing.
- 2.3. See **Section 1. External Inspection**, in **Appendix A** of this Standard for remainder of inspection requirements.

3. INTERNAL INSPECTION

Internal inspections include the above operating check requirements, plus the following:

- 3.1. Internally inspect all mainstream regulators.
- 3.2. See **Section 4. Check Station Condition**, in **Appendix A** of this Standard for remainder of inspection requirements.

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Inspection Schedule - Regulator Station, Power Generating Plant Regulation Equipment Requirements	SCG:	184.0275
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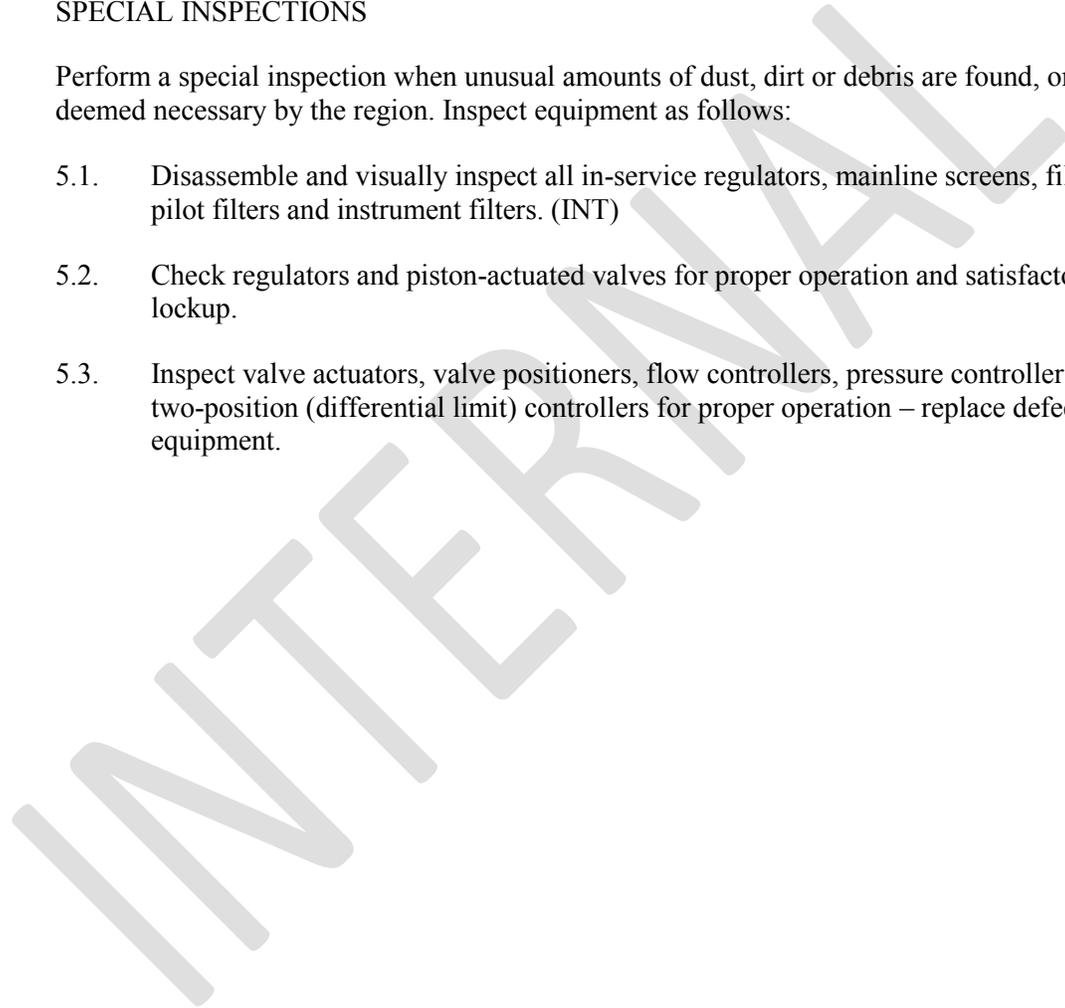
4. IPR (INTERNAL W/PARTS REPLACEMENT)

A rebuild includes the internal inspection requirements plus rebuild all regulators. This includes replacing all soft parts including diaphragms and expansible elements. There is no requirement to internally inspect or replace parts in the valve portion of a ball valve regulator. For ball valve regulators, replace parts only if inspection indicates a need.

5. SPECIAL INSPECTIONS

Perform a special inspection when unusual amounts of dust, dirt or debris are found, or when deemed necessary by the region. Inspect equipment as follows:

- 5.1. Disassemble and visually inspect all in-service regulators, mainline screens, filters, pilot filters and instrument filters. (INT)
- 5.2. Check regulators and piston-actuated valves for proper operation and satisfactory lockup.
- 5.3. Inspect valve actuators, valve positioners, flow controllers, pressure controllers and two-position (differential limit) controllers for proper operation – replace defective equipment.





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Inspection Schedule - Regulator Station, Power Generating Plant Regulation Equipment Requirements	SCG:	184.0275
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NOTE: Do not alter or add any content from this page down; the following content is automatically generated.

Brief: Section 3.5, Maximo was added to the Definitions.
 Section 4.6.3 was revised to revised and now references paragraph 4.7 of the gas standard.
 Section 6, was revised as Inspecting a regulator station that is shut in, de-energized, lock out tag out, due to project work or other circumstances.
 Section 7, was revised as Company assets that are unable to be inspected within the compliance window.
 Sections 6 and 7 to address shut in regulator stations when normal operating pressure is not available.

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Part of Non-O&M Parts 191-193 Plan	No
Non-O&M 49 CFR Codes & Impacted Sections of Document	
Part of Distribution IMP (DIMP)	Yes
Part of Transmission IMP (TIMP)	Yes
Part of Storage IMP (SIMP)	No
Impacts GO112F	No
GO112F Codes & Impacted Sections of Document	
Impacts Underground Gas Storage Projects (DOGGR)	No



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Gas Standard
Gas Engineering**

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14 CCR Codes & Impacted Sections of Document	
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GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	DIMP2, MR, TIMP2, TRNG
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INTERNAL

PRODUCT SPECIFICATIONS

TVA2020 Toxic Vapor Analyzer

Lightweight, intrinsically safe portable FID/PID detector

The Thermo Scientific™ TVA2020 Toxic Vapor analyzer is the only intrinsically safe, portable field analyzer using both Flame Ionization Detection (FID) and Photo Ionization Detection (PID) technologies.

Features

- Dual FID/PID technology
- Bluetooth enabled
- Lightweight and compact design
- Easy to service in the field
- No PC based software required

Introduction

The Thermo Scientific TVA2020 Toxic Vapor Analyzer is capable of detecting virtually all organic and inorganic compounds. The TVA2020 analyzer can be configured for use in diverse applications including U.S. EPA Method 21 monitoring, site remediation, landfill monitoring, and general area surveys.

The TVA2020 analyzer is equipped with a Flame Ionization Detector to measure organic compounds with high sensitivity. The FID technology allows for a wide dynamic and linear range that produces stable and repeatable responses. The analyzer can be configured with both FID and PID technology for simultaneous detection and enhanced analytical capabilities. This dual configuration is capable of producing a more rapid reading of organic



and inorganic compounds as opposed to a single detector technology and provides more comprehensive gas coverage than comparable size devices. After performing a primary calibration, the TVA2020 analyzer can be customized by activating internal logging parameters, uploading a monitoring route, establishing a bluetooth connection, setting alarm levels, and activating response factors.

Optional bluetooth communication permits the streaming of concentration data to a handheld device containing the LDAR software database, thereby eliminating the need to transfer files post monitoring and provide a greater access to route information.

The TVA2020 analyzer is 21% lighter than earlier models and more compact than most FID stand alone instruments. The lightweight and compact design reduces fatigue for true portability. In addition, a variety of options are available such as a basic or enhanced probe, carrying case, and hydrogen refill assembly.



Thermo Scientific™
TVA2020 Toxic Vapor Analyzer

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Thermo Scientific TVA2020 Toxic Vapor Analyzer

Specifications	
Accuracy	FID Instrument – ±10% of reading or ±1.0 ppm, whichever is greater, from 1.0 to 10,000 ppm. PID Instrument – ±20 % of reading or ±0.5 ppm, whichever is greater, from 0.5 to 500 ppm.
Repeatability	FID Instrument – ±2% at 500 ppm of methane PID Instrument – ±1% at 100 ppm of isobutylene
Linear range	FID Instrument – 1.0 to 50,000 ppm of methane PID Instrument – 0.5 to 2,000 ppm of isobutylene
Response time	FID Instrument – Less than 3.5 seconds for 90% of final value, using 10,000 ppm of methane PID Instrument – Less than 3.5 seconds for 90% of final value, using 500 ppm of isobutylene
Sample flow rate	1 liter/minute, nominal, at sample probe inlet
Battery	The battery operating time is 10 hours minimum at 0 °C (32 °F). Fully charged in less than 10 hours.
Hydrogen supply operating time	10 hours of continuous operation, starting from a cylinder charged up to 15.3 MPa (2200 psi)
Physical dimensions	11.5" × 9" × 4" (29.2 cm × 22.9 cm × 10.2 cm)
Weight	FID only—9.2 lbs Dual—9.4 lbs
Minimum detectable limit	The minimum detectable level is defined as seven times the standard deviation of peak-to-peak noise. FID Instrument - 0.5 ppm of methane PID Instrument - 0.5 ppm of isobutylene
Lamp life	FID Instrument - Greater than 5,000 hours PID Instrument - Greater than 2,000 hours, with normal cleaning
Data storage interval	Auto mode – 1 per second to 1 per 999 minutes, user selectable VOC or FE Mode – 2 to 30 seconds, user selectable
Relative humidity range	15 – 95%

To maintain optimal product performance, you need immediate access to experts worldwide, as well as priority status when your air quality equipment needs repair or replacement. We offer comprehensive, flexible support solutions for all phases of the product life cycle. Through predictable, fixed-cost pricing, our services help protect the return on investment and total cost of ownership of your Thermo Scientific products.

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Ordering information

TVA2020 Toxic Vapor Analyzer

Choose from the following configurations/options to customize your own TVA2020 Toxic Vapor Analyzer

1. Voltage options

A = 120 VAC 50/60 Hz (NA)

B = 220/240 VAC 50/60 Hz (Europe)

C = 220 VAC 50/60 Hz (China)

2. Detector

3 = Flame Ionization Detection (FID)

4 = Dual configured with FID and Photo Ionization Detection (PID)

5 = FID (Made in China)

6 = Dual (Made in China)

3. Probes

N = No probe

S = Sampling probe

A = Enhanced Probe

C = Both sampling and enhanced probes

4. Outputs

1 = None

2 = Bluetooth

3 = GPS

4 = Both bluetooth and GPS

5. Shipping

N = None

C = Transportation case

R = Hydrogen refill assembly

B = Case and refill assembly

6. Certification

2 = USA: Class I, Division 1, Groups A,B,C,D T3

Canada: Class I, Zone 1, Ex db ib IIC T3 Gb

ATEX: CE0359 Ex II 2 G Ex db ib IIC T3 Gb

IECEX: Ex db ib IIC T3 Gb

3 = NEPSI / IECEX (Made in China-Chinese Text)

4 = ATEX / IECEX (Made in China-English Text)

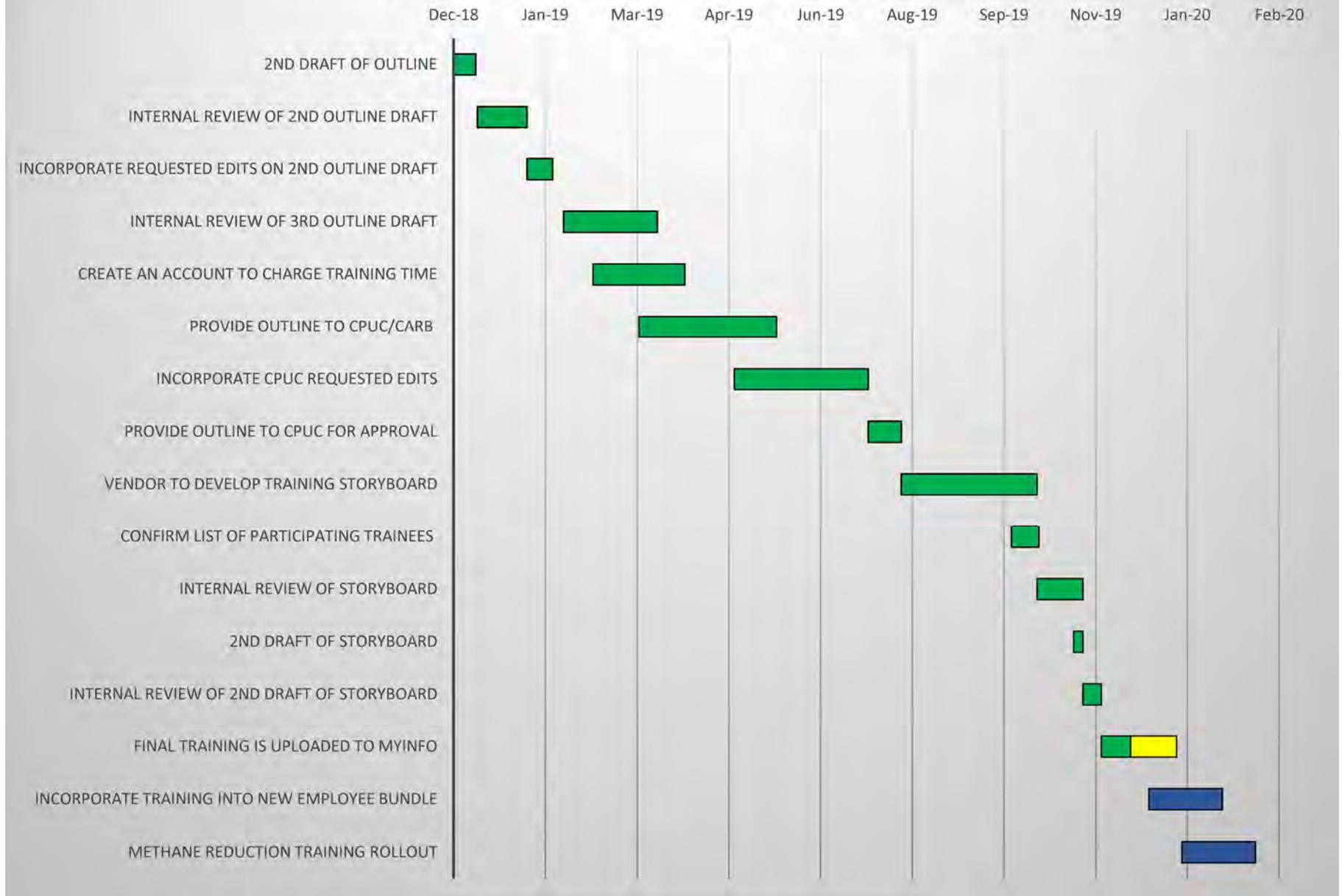
Your Order Code: TVA2020 -

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Find out more at thermofisher.com/tva2020

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Chapter 26 - Methane Emissions Training



Above Ground Leakage Classification and Mitigation Schedules	SCG:	223.0126
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PURPOSE: To establish guidelines and requirements for assessing the degree of hazard and classification of leaks or leak indications found on above ground Company piping system, and actions required to provide for public safety and repair of the leak.

1. POLICY AND SCOPE

- 1.1. Leak indications on Company facilities are classified by trained and qualified employees according to location, spread, concentration of gas, possibility for accumulation of gas, possible sources of ignition, potential migration and imminence of hazard to people or property. Classifications of leaks or leak indications are based on a relative degree of hazard and examples listed are intended only as a guide. The judgment of the person evaluating the leak or leak indication, after consideration of all factors involved, is the primary criterion for classification and mitigation.
- 1.2. Classification of a leak or leak indication establishes a maximum time limit from date of detection for taking corrective action. Dates may be set for action prior to the maximum time limit for safety, public relations reasons, or other special considerations by trained and qualified employees.

Note: In a situation where a leak requires an earlier scheduled repair, the employee must contact supervision and share all pertinent information by the end of that working day. The Supervisor must take the necessary actions to bring these situations to the attention of the individual responsible for scheduling leakage repair to expedite the leak repair.

Note: Although a repair of a classified leak may be expedited for a variety of reasons, the original classification of the leak shall not be changed.

- 1.3. In the event that leakage is discovered in the vicinity of a pipeline operating at greater than 60 PSIG, refer to [GS 183.06](#), *Reports of Safety-Related Pipeline Conditions*, to determine any additional reporting requirements and actions.

Note: Storage piping solely under the jurisdiction of the Department of Oil, Gas, and Geothermal Resources (DOGGR) is not subject to these policies. DOT-defined Distribution piping includes the meter set assembly (MSA) up to the inlet of the Customer's piping.

2. RESPONSIBILITIES AND QUALIFICATIONS

- 2.1. **Pipeline Integrity** is responsible for the specific guidelines as it relates to regulatory requirements and ensuring compliance with the Company's Integrity Management Plan.

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Above Ground Leakage Classification and Mitigation Schedules	SCG:	223.0126
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- 2.2. **Gas Operations Staff and Technical Service** is responsible for the process of duties performed and the equipment utilized for assessing the degree of hazard and classification of leaks or leak indications found.

- 2.3. **Distribution, Transmission, Storage, M&R and Customer Services** qualified field employees are required to classify all leaks identified on above ground (not buried) DOT Transmission and Distribution Defined Company pipelines and facilities in accordance with this gas standard.
 - 2.3.1. Field employees must notify local Supervision of all leaks identified on above ground facilities within Storage or Compressor Stations the same day the leak indications are discovered.

- 2.4. Assigning leakage classifications must be performed by trained and qualified individuals refer to [GS 167.0100](#), *Operator Qualification Program*.

- 2.5. When **any Company department** detects a non-hazardous leak or leak indications on a facility operated by another Company department, notification to that department shall be made the same day or within one business day.

Note: A company employee finding hazardous leak indications must remain at the location performing activities to their ability and training to keep themselves, the public and the area safe until the responding employee(s) to correct the leak has arrived.

- 2.6. **Gas Operations Training** is responsible for ensuring the equipment and facilities used by an Operator for training and qualification of employees must be identical, or very similar in operation to the equipment and facilities which the employee will use, or on which the employee will perform the covered task per GO112-F 143.4.

- 3. DEFINITIONS
 - 3.1. **Explosive Limits for Natural Gas** - 4.5% to 15% Gas Volume (gas / air mixture).
 - 3.1.1. **Lower Explosive Limit (LEL)** - 4.5% Gas Volume (100% of the LEL) indicate the lower explosive range of gas.

 - 3.2. **Repair** - As it relates to this Gas Standard, is defined as a permanent modification to the gas facilities that eliminates the natural gas leak.

 - 3.3. **Permanent Repair** – As it relates to this Gas Standard, is defined as an approved modification or installation of an approved fitting to the gas facility which eliminates the leak. Permanent repairs are conducted per Gas Standards and do not require any additional return visits to address the original leak indications.

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Above Ground Leakage Classification and Mitigation Schedules	SCG:	223.0126
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- 3.4. **Temporary Repair** - As it relates to this Gas Standard is defined as a temporary modification to the gas facilities that eliminates the natural gas leak and will require a return visit to complete a permanent repair.

- 3.5. **Remote location** - As it relates to this Gas Standard is defined as a company facility that is located a sufficient distance from any building or structure intended for human occupancy, roadways, and walkways (excluding roadways and walkways within Company facilities that are restricted from public access).

- 3.6. **Leak** – A leak is defined as an unintentional escape of gas from a gas facility.

- 3.7. **Leakage Coding** – As it relates to GO 112 F within this document – A “Grade 1” leak is referred to as a Code 1 leak, a “Grade 2” leak is referred to as a Code 2 leak, and a “Grade 3” leak is referred to as a Code 3 leak.
 - 3.7.1. Below ground leak indications are coded, see [GS 223.0125](#), *Below Ground Leakage Coding and Mitigation Schedule*.
 - 3.7.2. Above ground leak indications are classified.

- 3.8. **Leak Concentration** - The amount of leakage registered on the leak detection instrument.

- 3.9. **MSA Leaks** –Leaks on the above ground piping, downstream of the riser and including the service valve, see Figure 1.

Note: Service valve leaks or service valve replacements that require modification to the riser shall be classified as a riser leak, such as but not limited to, cut and thread repair due to corrosion.

- 3.10. **Riser Leaks** – Leaks on the above ground portion of service piping between the ground and service valve see figure 1.

Note: Any leak that can be resolved by service valve replacement or adjustment that does not require modification to the riser shall be classified as a MSA leak. Service valve leaks repaired by lubrication, tightening or adjustment shall be considered part of the MSA.

- 3.11. **Buried Service Leaks** – Leaks on service piping below ground, including the vertical buried portion of the service pipe. These leaks should be coded 1, 2 or 3, see [GS 223.0125](#), *Below Ground Leakage Coding and Mitigation Schedule*.

Note: Below ground leaks are never classified Hazardous, Non-Hazardous or Minor.

Company Operations Standard Gas Standard Gas System Integrity Staff & Programs

Above Ground Leakage Classification and Mitigation Schedules	SCG:	223.0126
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3.12. ABOVE GROUND (NOT BURIED) LEAKS

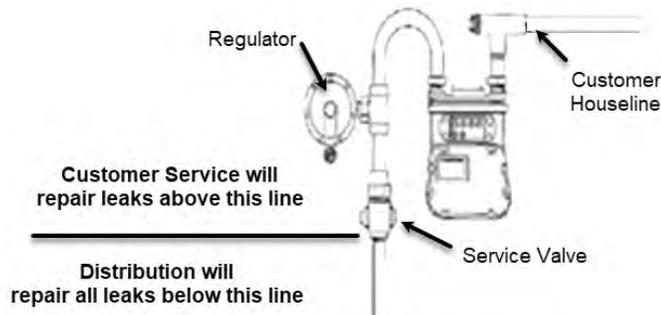


FIGURE 1

3.12.1. **HAZARDOUS LEAK (Grade 1)** - an above ground leak that represents an existing or probable hazard to persons or property, and requiring prompt action, immediate repair (temporarily or permanently) and continuous action until the conditions are no longer hazardous.

Note: Temporary or permanent repairs must be made to eliminate the immediate hazard however; hazardous leak repairs must be scheduled and completed per **Section 4.1.1** of this Gas Standard.

3.12.2. **NON-HAZARDOUS LEAK (Grade 2)** - an above ground leak that is recognized as being not-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.

Note: Leaks at ground level (where buried pipe comes out of the ground) may be classified as an "above ground" leak, provided the area around the pipe is not paved, gas has not migrated away from the pipe, and the entire leaking area of pipe can be exposed by moving away top soil by hand.

3.12.3. **MINOR LEAK (Grade 3)** - An above ground leak on a Transmission or Storage maintained facility; that is greater than 3 feet from a building or structure and is determined to be non-hazardous and can be eliminated by tightening, lubrication, or adjustment.

Note: Leaks caused by corrosion shall **NOT** be classified as Minor Leaks. Service valve leaks where the service valve must be replaced, the leak shall **NOT** be classified as a Minor Leak.

Leaks can be classified as Minor even if Company personnel elect to reconstruct the piping or replace parts; this includes activities such as replacing stem packing, gaskets, etc.

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Table A: ABOVE-GROUND LEAK INDICATION CLASSIFICATION CRITERIA

LEAK INDICATION CLASSIFICATION	The corresponding classification applies to the conditions and actions listed below	
	CONDITIONS / ENVIRONMENT	ACTIONS (One or more actions may be required)
HAZARDOUS (Grade1)	<ul style="list-style-type: none"> - Ignited leak. - Is in a location where the leak could be ignited and pose an immediate danger to public or property. - Leaks within 3 ft of a building or structure that, when assessed by soap test, blows off leak soap. (Refer to GS 184.0150, <i>Leak Testing of Distribution Piping with MAOP <= 60 PSIG</i> for soap test information). 	<ul style="list-style-type: none"> - Requires prompt action, immediate repair or continuous action until the leak is repaired (temporarily or permanently) and the conditions are no longer hazardous; - Evacuation; - Delineation to control public access - Traffic delineation to control vehicular access; - Eliminating source of ignition; - Venting the area; - Stand-by; - Stopping the flow of gas by closing valves or other means; or - Notifying police and fire departments.
NON-HAZARDOUS (Grade 2)	<ul style="list-style-type: none"> - Leak is not ignited. - Does not pose an immediate danger to public or property. - Leaks within 3 ft of a building or structure that, when assessed by soap test forms soap bubble(s). (Refer to GS 184.0150, <i>Leak Testing of Distribution Piping with MAOP <= 60 PSIG</i> for soap test information). 	Follow procedures in section 4.1.2.
MINOR* (Grade 3)	<ul style="list-style-type: none"> - Leaks on Transmission and Storage maintained facilities. - Leaks greater than 3ft from a building or structure. - Leaks or releases that are non-hazardous at the time of detection and can be repaired by tightening, lubrication, or adjustment. 	Follow procedures in section 4.1.3.
<p>*Aboveground leaks that are determined to be non-hazardous at the time of detection on Distribution, M&R, and Customer Services maintained facilities will no longer be classified as MINOR leaks at the time of detection and must be classified as Aboveground Non-Hazardous.</p>		
<p>Note: For Transmission, Storage, and Distribution employees working on an above ground system operating at greater than 60 PSIG, the pipe and facility condition shall also be assessed per Company Form Instruction 677-1, <i>Pipeline Condition and Maintenance Report</i>.</p>		

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4. PROCEDURE

4.1. Above Ground Leak Classification, Response and Mitigation

Note: Above ground leaks on DOT-defined Transmission, Storage and Distribution piping shall be classified according to the definitions and criteria specified within this gas standard as Hazardous, Non-Hazardous, or Minor. The response and mitigation schedule for leaks on Above Ground Facilities shall be as follows:

4.1.1. Hazardous Leaks on Above Ground Pipelines

4.1.1.1. All Hazardous leak indications excluding risers and MSA require prompt action, immediate repair (temporarily or permanently), and continuous action until the conditions are no longer hazardous.

Note: Temporary repairs may be made (except on risers and MSA hazardous leaks) to eliminate the immediate hazard. Refer to 4.1.1.2 and 4.1.1.3.

4.1.1.2. Actions taken for Hazardous leak indications in **Distribution, Transmission, and Storage** are in accordance with [GS 183.03, Field Guidelines - Emergency Incident Distribution / Customer Service](#) and [GS 223.0100, Leakage Surveys](#).

Note: The Supervisor of the organization repairing the leak must be notified for all Hazardous leaks.

4.1.1.3. Distribution

4.1.1.3.1. When a temporary repair is made on a Hazardous leak, the leak must be reevaluated at least once every 6 months from the original date detected.

4.1.1.3.1.1. Temporary leak repairs on pipelines operating at 60 PSIG or less must be permanently repaired no later than 15 months from the original date detected.

4.1.1.3.1.2. Temporary leak repairs on pipelines operating at greater than 60 PSIG must be permanently repaired within 1 year from the original date detected

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4.1.1.4. Transmission and Storage

- 4.1.1.4.1. When a Hazardous leak is temporarily repaired on a pipeline operating at greater than 60 PSIG, a permanent repair must be scheduled and completed within 6 months from the original date detected.

Note: In situations where permanent repairs cannot be completed within the six-months, the reason for delay and the steps taken to ensure public safety shall be documented monthly until the leak is permanently repaired not to exceed one year from the original date detected.

- 4.1.1.4.2. The Supervisor of the organization repairing the leak must be notified for all Hazardous leaks. The Supervisor shall notify management immediately for all Hazardous leaks.

4.1.2. Non-Hazardous Leaks

- 4.1.2.1. When determining repair schedule for non-hazardous leaks, the proximity of gas to buildings and structures shall be considered.

4.1.2.2. Distribution

Note: All Non-hazardous riser leaks may be temporarily repaired using company approved clamps, see 4.1.2.2.5.

- 4.1.2.2.1. Leaks within 3 feet of a building or structure, shall be repaired (temporarily or permanently) within 10 business days from the date the leak was detected.

4.1.2.2.1.1. Temporary leak repairs on pipelines operating **60 PSIG or less** must be permanently repaired no later than 15 months from the original date detected.

4.1.2.2.1.2. Temporary leak repairs on pipelines operating at **greater than 60 PSIG** must be permanently repaired within 1 year from the original date detected.

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Note: One-Call / USA notification requires 2 business days for non-emergency response by other utilities before excavating. Refer to [GS 184.0200](#), *Underground Service Alert and Temporary Marking* for more information.

CA law AB1937 requires a notification of 3 business days to qualifying School, Hospital and / or Registered Licensed Day Care Facility within 500 feet proximity prior to planned construction excavation activity on gas facilities.

- 4.1.2.2.2. Leaks greater than 3 feet from a building or structure that is not in a remote location, the leak must be repaired within 6 months from the date the leak was detected.
 - 4.1.2.2.2.1. When a temporary repair is made on a Non-Hazardous leak, the leak must be reevaluated at least once every 6 months from the date detected.
 - 4.1.2.2.2.2. Temporary leak repairs on pipelines operating **60 PSIG or less** must be permanently repaired no later than 15 months from the original date detected.
 - 4.1.2.2.2.3. Temporary leak repairs on pipelines operating at **greater than 60 PSIG** must be permanently repaired within 1 year from the original date detected.
- 4.1.2.2.3. Leaks on pipelines operating 60 PSIG or less in remote locations that are considered non-hazardous must be permanently repaired within 15 months from the original date detected.
- 4.1.2.2.4. Leaks on pipelines operating at greater than 60 PSIG in remote locations that are considered non-hazardous must be permanently repaired within 1 year from the original date detected.
 - 4.1.2.2.4.1. When a temporary repair is made on a Non-Hazardous leak, the leak must be reevaluated at least once every 6 months.

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4.1.2.2.4.2. All non-hazardous riser leaks may be temporarily repaired using company approved clamps, see [GS 184.0225](#), *Leak Repair Methods for Steel Distribution Pipelines*.

4.1.2.2.4.3. When a temporary leak repair is made on an Anodeless riser, the clamp (stock code N542491) shall be installed in accordance with [GS 184.0121](#), *Service Riser Integrity Observation and/or Inspection*. Temporary leak repairs must be scheduled and permanently repaired as soon as practical, **not to exceed 10 business days from the date the temporary clamp was installed**.

4.1.2.2.4.4. When temporary leak repairs are made on a steel riser, the leak must be reevaluated at least once every 6 months and a permanent repair must be completed within 15 months from the date the leak was detected.

4.1.2.2.5. Shorter time frames for the response to Non-Hazardous Leaks may be scheduled when in the opinion of the responsible employee it is prudent for managing safety, public relation reasons, or other special considerations.

4.1.2.2.6. When leak indications are found in a Company-owned or controlled gas vault, entry into the vault is to be done in accordance with [GS 166.0077](#), *Confined Space Operations*.

4.1.2.2.7. When leaks are identified on above ground facilities within Storage or Compressor Stations, field employees must notify local supervision the same day the leak indications are discovered.

4.1.2.3. Transmission and Storage

4.1.2.3.1. When determining repair schedule for all non-hazardous leaks, the proximity of gas to buildings and structures shall be considered.

4.1.2.3.2. An investigation of a Non-Hazardous leak indication shall be conducted within 6 weeks of the date detected.

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4.1.2.3.2.1. Leaks within 3 feet of a building or structure shall be repaired within 10 business days from the date the leak was detected.

Note: One-Call / USA notification requires 2 business days for non-emergency response by other utilities before excavating. Refer to [GS 184.0200](#), *Underground Service Alert and Temporary Marking* for more information.

CA law AB1937 requires a notification of 3 business days to qualifying School, Hospital and / or Registered Licensed Day Care Facility within 500 feet proximity prior to planned construction excavation activity on gas facilities.

4.1.2.3.2.2. Leaks greater than 3 feet from a building or structure that is not in a remote location, the leak must be repaired within 6 months from the date the leak was detected using normal operational methods.

Note: In situations where permanent repairs cannot be completed within the six-months for leaks greater than 3ft from a building or structure, the reason for delay and the steps taken to ensure public safety shall be documented monthly in MAXIMO until the leak is permanently repaired. The leak must be repaired within one year from the original date of detection.

4.1.2.3.2.3. Leaks in remote locations that are considered non-hazardous must be permanently repaired within one year from the original date detected.

Note: For leaks in remote locations where permanent repairs cannot be completed within one year, the reason for delay and the steps taken to ensure public safety shall be documented in MAXIMO monthly until the leak is permanently repaired, not to exceed 18 months from the original date detected.

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- 4.1.2.3.3. Non-Hazardous leak indications in the upper range of the lower explosive limit (2.5% - 3% gas / air mixture) shall be monitored pending the leak repair. The frequency for monitoring shall be defined by the supervisor.

Note: In situations where permanent repairs cannot be completed within the six-months, the reason for delay and the steps taken to ensure public safety shall be documented monthly until the leak is permanently repaired, not to exceed one year from the original date detected.

- 4.1.2.3.4. When leak indications are found in a Company-owned or controlled gas vault, entry into the vault is to be done in accordance with [GS 166.0077](#), *Confined Space Operations*.
- 4.1.2.3.5. When leaks are identified on above ground facilities within Storage or Compressor Stations field employees must notify local supervision the same day the leak indications are discovered.

4.1.3. Minor Leak

- 4.1.3.1. Repairs are to be scheduled and performed as operations permit within 36 months of the date the leak was detected.

- 4.1.3.1.1. Minor leaks discovered before June 15th, 2017 must be repaired by June 15th, 2020.

5. EXCEPTION PROCEDURE

(See [GS 182.0004](#), Exception Procedure for Company Operations Standards)

- 5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.
- 5.2. An exception from a standard shall not be allowed unless [GS 182.0004](#), *Exception Procedure for Company Operations Standards*, is followed and approval is given by those as required by 182.0004.

6. OPERATOR QUALIFICATION COVERED TASKS

(See [GS 167.0100](#), *Operator Qualification Program, Appendix A, Covered Task List*):

- **Task 09.05** - CFR 192.703, 192.723(b) - Leakage Assessment.

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- **Task 09.06-9999** - 49 CFR 192.703 - Above Ground Leak Classification.

7. RECORDS

- 7.1. **Data Requirements for Above Ground Leaks:** Except for Minor leaks, Above Ground Hazardous and Non-Hazardous leaks are to be documented by each impacted operating organization. The minimum required data includes the leak Classification, Cause, and Component category.
- 7.2. **Transmission:** Leak records are documented on [Form 677-1, Pipeline Condition and Maintenance Report](#). For all documentation instructions and requirements, refer to [Form 677-1, Pipeline Condition and Maintenance Report](#) company form instructions. The PCMR can be completed electronically or paper forms
- 7.3. **Storage:** Except for minor leaks, leak records are documented on [Form 677-1, Pipeline Condition and Maintenance Report](#). For all documentation instructions and requirements, refer to [Form 677-1, Pipeline Condition and Maintenance Report](#) company form instructions. The PCMR can be completed electronically or paper forms. Minor leaks are documented in MAXIMO.
- 7.4. **Distribution:** Leak records are documented as follows:
- **Form 4040**, Leak Investigation Order
 - **Form 4060**, Leak Re-Evaluation Order
 - [Form 4050, Leak Repair Order PDF](#), Leak repairs on mains, services and risers
 - **Form 4070**, *Leak repair Order*, Leak repair on the MSA
 - [Form 677-1, Pipeline Condition and Maintenance Report](#) (PCMR), when a leak is repaired on a pipeline operating at greater than 60 PSIG, a description and all pertinent information concerning the repair(s) or any other disposition of the leak is made on **Form 677-1**; CM work orders and PCMRs are to be cross referenced. CM orders are completed and electronically filed in SAP. PCMRs are completed and filed according to [Form 677-1](#) instructions
- 7.5. **Measurement and Regulation:** Distribution M&R inspections and leak repairs are captured by CLICK Mobile. Transmission M&R inspections and leak repairs are captured by a PDF version of the form. Above Ground Leaks will be captured using Leak Classification & Repair Form (**Form 5290** for FL and **Form 5590** for EQ).
- 7.6. **Customer Service Field:** Leak records are documented in PACER and shall include the leak classification, cause, facility location, leaking component, conditions found, and a description of the subsequent repairs or other disposition of the leak.

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- 7.7. Records of leaks discovered, and repairs made are filed by the appropriate Transmission District, Storage Field, Customer Service or Distribution operating organizations.
- 7.8. **Transmission Lines: Recordkeeping:**
- 7.8.1. All records of leaks discovered and repaired are kept on file at Gas Transmission in MAXIMO.
- 7.8.2. All leaks found and not immediately repaired must have a corrective MAXIMO work order completed.
- 7.8.3. Retain original paper order in file per Records Management Retention Schedule. See Records Retention Standards on Sempra Net, <http://home.sempranet.com/rm/>.
- 7.8.4. In addition to the other recordkeeping requirements of these rules, each Operator shall maintain the following records for transmission lines for the periods specified:
- A. The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipeline remains in service or there is no longer pipe within the system of the same manufacturer, size and / or vintage as the pipeline on which repairs are made, whichever, is longer.
 - B. The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 75 years. Repairs or findings of easement encroachments, generated by patrols, surveys, inspections, or tests required by subparts L and M of 49 CFR Part 192 must be retained in accordance with paragraph (c) of this section.
 - C. A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 75 years.
8. APPENDICES
- 8.1. N/A



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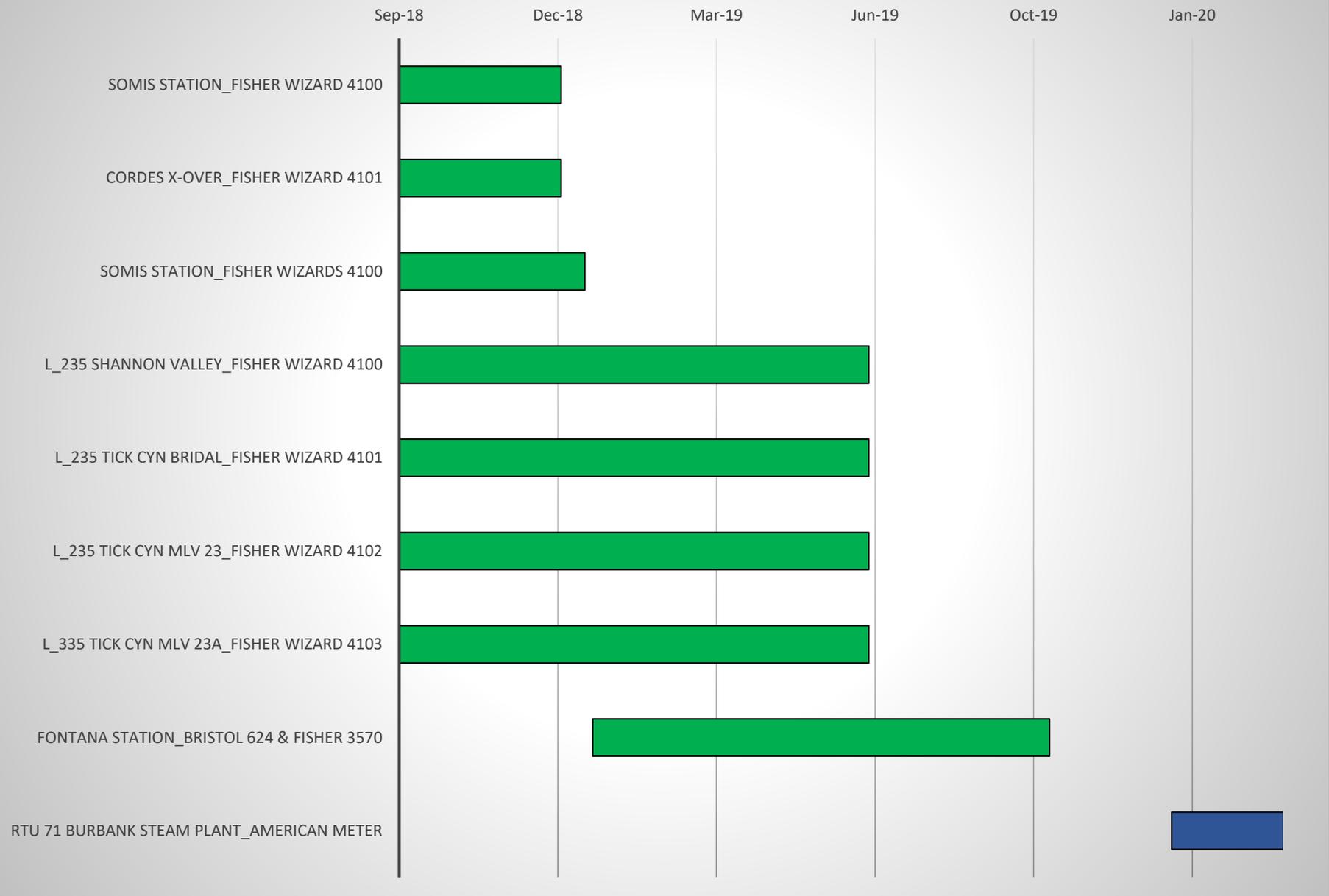
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NOTE: Do not alter or add any content from this page down; the following content is automatically generated.

Brief: In Section 3.12.1, added (Grade 1) to Hazardous Leak. In Section 3.12.2, added (Grade 2) to Non-hazardous leak. In Section 3.12.3, added (Grade 3) to Minor leak. In Table A: Above-Ground Leak Indication Classification Criteria added Grade 1, Grade 2 and Grade 3 to meet GO 112F requirements.

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Chapter 28 - High Bleed Pneumatic Device Replacement Projects



Leakage Surveys	SCG:	223.0100
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PURPOSE To describe the methods, required intervals, and record keeping requirements for leakage survey on Company’s facilities. The objective of a leakage survey is to conduct a thorough search for gas leak indications in an assigned area and report all detectable leaks using an approved survey method.

1. POLICY AND SCOPE

- 1.1. Leakage surveys are performed by Transmission, Distribution and Storage of gas facilities at specified intervals by using the methods specified in this Gas Standard. This document establishes the frequency of leak surveys and specifies record keeping procedures to comply with Company and regulatory requirements.

2. RESPONSIBILITIES AND QUALIFICATIONS

- 2.1. **Field Organizations (Gas Transmission Districts, Distribution Regions, and Storage Operations)** are responsible for performing leak surveys per this procedure at the minimum intervals identified in **Section 4**. Surveys may be performed at more frequent intervals.
- 2.2. **Field Organizations (Gas Transmission Districts, Distribution Regions, and Storage Operations)** are responsible for selecting the appropriate leak survey method for each portion of their facilities per **Table 3** of this procedure.
- 2.3. **Distribution, Transmission, and Storage** qualified field employees are required to notify Supervision of all leak indications on a buried pipeline with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing). See [GS 184.0245](#), *Leak Investigation*.
- 2.4. **Distribution, Transmission, and Storage Supervisors** are required to notify the appropriate Gas Operations Area Manager Transmission District Operations Manager, and Storage Operations Manager. See Section [GS 184.0245](#), *Leak Investigation*.
- 2.5. **Field Organizations (Gas Transmission Districts, Distribution Regions, and Storage Operations)** are responsible for notifying the appropriate scheduler of maintenance inspections of any field conditions which may warrant a change in the leak survey schedule.
- 2.6. The employee performing the leakage survey must be qualified per [GS 167.0100](#), *“Operator Qualification Program.”*
- 2.7. If a boat is required for performing a leakage survey, the watercraft used must comply with the governmental regulations and licensing requirements for its type.

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2.7.1. The operator of any rented or owned Company boat must first complete and successfully pass a Boating Safety Course approved by the California Department of Boating and Waterways (CDBW).

2.7.2. The CDBW offers a boating course at no charge. See the website at <http://www.dbw.ca.gov>.

2.7.2.1. Personnel working in watercraft MUST wear a Coast Guard-approved life vest.

Other recommended PPE:

- Mosquito repellent.
- Sunscreen.

3. DEFINITIONS

3.1. **Barhole:** Probing or drilling holes in the surface (approximately 18 inches deep) to identify leakage using an approved leak detection instrument.

3.2. **Business District** – Is an area identified on a leak survey map that depicts where distribution facilities are located within 100 feet of the property line of a land parcel that has been identified as being a potential commercial gathering place, a church, a school, a hospital or is location where people have limited mobility. The extent of the business district boundaries have been determined per the procedure outlined in [GS 223.0102](#), *Updating of Leak Survey Maps*.

3.3. **Department of Transportation Defined Transmission Line (DOT-T)** – See [GS 223.0415](#), *Pipeline and Related Definitions*.

3.4. **DP-IR: The Detecto Pak-Infrared®** is a portable optical-based methane gas detector to sample the atmosphere for gas near the ground surface using Infrared Controlled Interference Polarization Spectrometry. For additional instrumentation specifications, see [GS 107.0294](#), *DP-IR Heath Detecto Pak-Infrared*.

3.5. **HCA** – High Consequence Area. Refer to [GS 192.02](#), *Procedure for HCA Segment Identification*.

3.6. **Location Class** – See [GS 182.0190](#), *Location Class – Determination and Changes*

3.7. **Maximum Allowable Operating Pressure (MAOP)** See [GS 223.0415](#), *Pipeline and Related Definitions*.

3.8. **Non-State-of-the-Art Pipe (NSOTA)** – Steel pipe, bare or coated, without cathodic protection (CP), and all DuPont Aldyl-A (PE) pipe installed before 1986. See [GS 184.03](#), *Replacement Criteria for Distribution Mains and Services*.

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- 3.9. **OMD: The Optical Methane Detector** method uses an optical-based methane detector mount in front of a vehicle to detect gas that passes between the light transmitter and receiver. The presence of methane is displayed in analog and digital form inside the vehicle. See [GS 223.0104](#), *Optical Methane Detector Operation and Maintenance*

 - 3.10. **RMLD: The Remote Methane Leak Detector** – used as a portable “line of sight” laser based methane gas detector to detect gas leaks from a remote distance (up to 100’) by passing a laser through a gas plume. See [GS 107.0293](#), *RMLD-Remote Methane Leak Detector*.

 - 3.11. **State-of-the-Art Plastic Pipe (SOTA)** – Yellow or Orange TR418 resin, and 1986 and later Aldyl-A pipe. See [GS 184.03](#), *Replacement Criteria for Distribution Mains and Service*.
4. PROCEDURE
- 4.1. Table 1 is a summary of the minimum leak survey frequencies for pipe based upon location and operating status. See the referenced section of this procedure listed in Table 1 under ‘Additional Requirements for detailed requirements.

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Table 1: Leak Survey Frequencies

Pressure	Operating Location or Operating Status	Frequency	Additional Requirements
Medium Pressure	Main Located Within a Business District and associated services	At least once each calendar year	see Sect. 4.1.2.1
	All Non-State-of-the-Art PE main located outside a Business District and associated services	At least once each calendar year	see Sect. 4.1.2.2
	Main Located Outside of a Business Districts and cathodically unprotected and associated services	At least once every 3 calendar years	see Sect. 4.1.2.3
	All other medium pressure main located outside a Business District and associated services	At least once every 5 calendar years	see Sect. 4.1.2.4
High Pressure (over 60 psig)	All high-pressure pipe not including DOT-T Pipe	At least once each calendar year	see Sect. 4.1.3.1
DOT Defined Transmission Pipe (DOT-T)	Located in Non-HCA, Class 3	At least twice each calendar year	see Sect. 4.2.1.1
	Located in Non-HCA, Class 4	At least 4 times each calendar year	see Sect. 4.2.2.1
	Cathodically Unprotected Pipe, located in All Classes	At least 4 times each calendar year	see Sect. 4.2.2.2
	All other DOT-T Pipe	At least twice each calendar year	see Sect. 4.2.1.1

4.1.1. See **GS184.0005**, *Scheduling Distribution Tests and Inspections*, for requirements of establishing anniversary months.

4.1.2. **Medium Pressure Pipelines (Operating at 60 psig or Less)**

4.1.2.1. Survey all pipe (including services) in business districts at intervals not exceeding 15 months, but at least once each calendar year.

4.1.2.2. Survey Non-State-of-the-Art PE main pipe and connected services where the main is not located in a business district once every calendar year, at intervals not exceeding 15 months.

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4.1.2.3. Survey cathodically unprotected main pipe and connected services where the main is not located in a business district at least once every 3 calendar years at intervals not exceeding 39 months.

4.1.2.4. Survey PE and cathodically protected main pipe and connected services where the main is not located in a business district once every 5 calendar years at intervals not exceeding 63 months.

4.1.3. **High Pressure Pipelines (Operating over 60 Psig) not including DOT-Transmission Pipelines**

4.1.3.1. Survey all pipelines and associated taps, cross-over piping, services and other piping every 15 months; but at least once every calendar year annually for all location classes.

4.2. **DOT-Transmission Pipelines**

4.2.1. **Non-HCA Transmission Pipeline Segments in Location Class 3* and all DOT-T pipe not covered in Section 4.2.2.1 and 4.2.2.2.**

4.2.1.1. Survey every 7½ months; but at least twice each calendar year

4.2.2. **Non-HCA Transmission Pipeline Segments in Location Class 4 and Transmission Pipelines in all Location Class without CP**

4.2.2.1. Survey Non-HCA Transmission Pipeline in Location Class 4 every 4½ months; but at least 4 times each calendar year.

4.2.2.2. If no CP is on a transmission pipeline (in any Location Class) or if electrical surveys are impractical, then survey every 4½ months; but at least 4 times each calendar year.

4.3. **Special Survey**

4.3.1. Special leak surveys are one-time, additional survey to the routine scheduled survey that is driven by a specific circumstance. Perform special leak survey when:

4.3.1.1. Upon discovery that the MAOP of a pipeline is exceeded by 10% or more at any time during the life of the pipeline.

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Note: When the MAOP of a pipeline is exceeded by 10% or more, contact Pipeline Integrity for guidance concerning any additional actions to be taken that could facilitate further analysis of the longer-term impact on the integrity of the pipe.

- 4.3.1.2. After the occurrence of any significant incident (e.g., train derailment, explosion, earthquake, flooding, landslides, etc.) over or adjacent to high pressure pipelines or related facilities. See **GS183.03**, *Field Guidelines – Emergency Incident Distribution / Customer Service* or [GS 183.0110](#), *Field Procedures- Emergency Incidents-Transmission* for confirming survey requirements.
- 4.3.1.3. There is the danger of public exposure to leaking gas; the special survey is performed using the appropriate leak detection method shown in Table 3. Document the reason, location, limits, and results of all special leak surveys on the appropriate Company inspection record.
- 4.3.1.4. When increasing the MAOP of a pipeline, per [GS 182.0040](#), *Changing Maximum Allowable Operating Pressure and Maximum Operating Pressure*.
- 4.3.1.5. When the routine scheduled survey frequency are not considered adequate because of pipe condition, limited opportunity for gas to vent safely, or other reasons. When the special surveys will be on-going and scheduled, efforts shall be made to identify the segment of pipe to be at the greater frequency in SAP and EGIS, and be scheduled as routine.
- 4.3.1.6. There is a need to monitor pipe condition for special situations, such as:
- 4.3.1.6.1. Material evaluations.
 - 4.3.1.6.2. Proposed street improvement projects.
 - 4.3.1.6.3. As a mitigated measure for the Integrity Management Program.
- 4.3.1.7. Survey at the frequency listed in Table 2 based upon the location of the known shorted casing, confirmed to be shorted through inspection and testing and have not been repaired/cleared according to [GS 186.06](#), *Cathodic Protection – Electrical Isolation*

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Table 2: Known Shorted Crossing Survey Frequency

Location Class	Frequency
Highway and Railroad Crossings	7½ months; but at least twice each calendar year
All Other Locations	15 months; but at least once every calendar year

- 4.3.2. *A special leak survey may require special accounting; contact Field Operations Supervisor for proper account numbers.*
- 4.3.3. *Special leak survey may also be considered in conjunction with major underground construction projects, see [GS 184.09](#), *Prevention of Damage to Company Facilities*.*
- 4.3.4. *After the occurrence of lightning strikes, transformer arcs, stray current or other electrical discharge events involving company facilities.*
 - 4.3.4.1. *Electrical current induced onto facilities will take all paths to ground.*
 - 4.3.4.1.1. *Lightning strikes and high voltage electrical discharge events can result in multiple damages and leaks*
 - 4.3.4.1.2. *Induced voltage on foreign facilities or substructures due to lightning strikes or electrical discharge events can also arc onto company facilities.*
 - 4.3.4.1.3. *Locating wire used for identifying PE pipe installations is electrically conductive and can damage pipe if induced.*
 - 4.3.4.2. *Survey all company facilities in the immediate vicinity of the area where the lightning strike or electrical discharge event occurred.*
 - 4.3.4.3. *Contact Region System Protection to identify the segment of pipe and determine the area to be surveyed.*

4.4. APPLICATION OF LEAK SURVEY METHODS

- 4.4.1. *Field Operations must follow Table 3 when selecting an approved method for performing leakage surveys of Transmission and Distribution Facilities.*

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Table 3: Approved Leak Survey Method by Facility

<i>Facility</i>	<i>DP-IR</i>	<i>OMD Mobile</i>	<i>RMLD</i>	<i>Barhole</i>	<i>Aerial Instrument**</i>
Med Press. Pipe (Annual, 3yr ,5yr)	X	*X	*X	X	
High Press. Pipe Over 60 psig (Annual)	X	*X	*X	X	X
DOT-T Transmission (Class 1,2)	X	*X	X	X	X
DOT-T Transmission (Class 3, 4)	X	*X	X	X	X
Shorted Casing	X		X	X	
Pipe over Waterways	X		X		

*see sub-section for limitations **Company approved vendor and equipment must be used

4.5. INSTRUMENTED SURVEY METHOD

4.5.1. The method consists of using an approved leak survey instrument listed in Table 3 to sample the atmosphere near the surface of the ground in the vicinity of buried company facilities, and in street openings and other accessible crevices and locations where gas is likely to vent.

4.5.2. Survey shall include visual examinations of all Company above ground facilities (See [GS 167.0100](#), “Operator Qualification Program”, Appendix B, *ABNORMAL OPERATING CONDITIONS*). Search along the route of the pipe at all locations where gas is most likely to vent. Determine pipe location as accurately as possible using map, existing paint marks, old patches, line markers, etc.

4.5.3. For non-mobile survey methods, choose locations such as loose earth, paving cracks, old bar holes, repair patches and around the base of poles, trees, fence posts, etc., if they are near the pipe.

4.5.4. Watch for, and check areas where vegetation appears to be affected by gas leakage.

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Note: Grass and vegetation areas can be affected in several ways: There may be patches of brown, dry, even dead grass. In some instances, affected vegetation and grass may appear very green compared to surrounding areas.

- 4.5.5. Search along the route of all services at locations where gas is most likely to vent using appropriate instrumentation.
- 4.5.5.1. Determine the service location as accurately as possible using the map, curb markings, meter location, etc. If any doubt exists as to route of the service such as at corner lots, check both possible routes.
 - 4.5.5.2. Search as close to the service location as practical, over earth, at building foundations or at cracks and/or paving edge if service is under paving.
 - 4.5.5.3. Search along all services from the curb or pavement edge to the riser. Check at service-to-main connections if traffic permits.
 - 4.5.5.4. Check all manholes and other street openings such as valve casings, curb meter vaults, drains, water valves, meter boxes, street lighting, power, telephone, etc.
 - 4.5.5.5. For long-side services it is necessary to visibly look for indications of possible leakage under the street such as: evidence of recent construction, foreign trench marks, pavement cuts, bar holes, etc. along the service route. Where visible indications are present, use approved ground leak detection equipment such as DP-IR or RMLD.
- Note: When casing vents are presents they must be inspected to ensure they are in satisfactory condition and designed to prevent entry of water, insects, and other foreign matter. Vents should extend at least four feet above finished grade and at least four feet below overhead electric wires. Vents shall be located in an area away from traffic and other hazardous locations.
- 4.5.5.6. Survey all risers and other above ground Company Infrastructure including meters set assemblies. If a riser and connected facility is not readily accessible by customer contact or other means during the regular survey, and the survey cannot be completed using the RMLD (see 5.2.5.7 below), the “cannot get in” (CGI) must be documented for a follow-up to complete the survey. Check the riser and any portion of the service that was not surveyed. The follow-up shall be completed within the established compliance window for the inspection (leak survey order).

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4.5.5.7. Districts have the option of utilizing a Remote Methane Leak Detector (RMLD) to check services up to the riser when access is restricted. See [GS 107.0293](#), *RMLD – Remote Methane Leak Detector*. Only qualified employees who are properly trained may use the RMLD for gas leak detection.

Note: Districts are responsible for tracking and completing services that are not accessible at the time of survey (commonly referred to as “Can’t Get Ins” (CGIs). Records should be kept per the retention scheduled identified Section 7.5.

4.5.5.8. Check the casing end inside the building when a service enters a building. Reseal the casing end.

4.6. OMD MOBILE SURVEY METHOD

INTERNAL

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- 4.6.1. This method consists of driving a vehicle along the route of the underground gas piping and sampling the atmosphere near the earth or paving over the pipe or paving edge with sensitive continuous sampling leak detection equipment especially designed and engineered for mounting on a vehicle. See [GS 223.0104](#), Optical Methane Detector Operation and Maintenance.
- 4.6.2. The OMD is to be used to perform leakage survey on buried high pressure and medium pressure pipelines.
 - 4.6.2.1. In paved locations survey is performed by driving along or as near as possible, the curb to the side of the street where the pipeline is located. In the instance of dual pipelines, particularly wide streets, pipelines in traffic islands or divided traffic lanes, a particular street may be traversed in both directions.
 - 4.6.2.2. In unpaved locations survey is performed by driving directly over or within 5 feet of the pipeline.

Note: Employees performing leakage survey must know the location of the pipeline and other subsurface substructures that are part of the survey work order. Pipeline location is determined using the map, curb markings, pipeline markers, etc.

- 4.6.2.3. Associated services, crossovers and other buried infrastructure that cannot be driven over shall be surveyed using appropriate instrumentation (See section 4.5) Any services, taps, or other pressure carrying facilities that are part of the survey work order and are not suitable for survey by OMD must be surveyed with an appropriate device (see Section 4.5)

Note: Check all manholes and other street openings such as valve casings, curb meter vaults, drains, water valves, meter boxes, street lighting, power, telephone, etc. with the appropriate equipment. See section 4.5.

4.7. BARHOLE

- 4.7.1. Prior to drilling bar holes, notify Underground Service Alert (USA). Refer to **GS184.0200**, *Underground Service Alert and Temporary Marking*.
- 4.7.2. Drill a hole over the suspected leak area and surrounding facilities for the specific purpose of testing for subsurface gas indications per **GAS GS 107.0287**, *GMI Gasurveyor – Combustible Gas Indicator (CGI)*.

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4.7.3. Use an instrument probe, such as the combustible gas indicator, e. g., GMI Gasurveyor – Combustible Gas Indicator (CGI). Read, interpret and code gas indications per [GS 223.0125](#), *Leakage Classification and Mitigation Schedules*.

4.7.4. The DP-IR can also be used for barhole survey by using the probe assembly. See [GS 107.0294](#), *DP-IR Heath Detecto Pak-Infrared*.

4.8. AERIAL INSTRUMENT LEAKAGE SURVEY

4.8.1. Aerial Instrument Leakage Survey utilizes company approved aerial instruments to detect indications of natural gas. Those indications are verified by company personnel using the procedures established in this Gas Standard. Once the leak indication is verified it is coded and scheduled for repair per [GS 223.0125](#) *Leakage Classification and Mitigation Schedules*. The aerial instrument leakage survey procedure is described in [GS 223.0103](#) *Aerial Leakage Surveys*.

4.9. WATER CROSSING

4.9.1. SAFETY

4.9.1.1. Serious bodily injury could occur when entering waterways without proper training and personal protective equipment (PPE). See sections 2.5 for required and recommended PPE.

4.9.1.2. The following are examples of hazards impacting this work:

4.9.1.2.1. Weather and waterway conditions

4.9.1.2.2. Fast currents

4.9.1.2.3. Tripping and slipping hazards.

4.9.1.2.4. Sunburn from water reflection.

4.9.1.2.5. Drowning

4.9.1.2.6. Hypothermia.

4.9.1.2.7. Other watercraft.

4.9.1.2.8. Wildlife

4.9.1.2.9. Environmental surroundings.

4.9.2. SPECIAL REQUIREMENTS

4.9.2.1. Use only approved leak survey instruments listed in Table 3.

4.9.2.2. Minimum 2-foot by 4-foot background target to reflect an RMLD laser. The following may be used as a background target:

4.9.2.2.1. A second watercraft.

4.9.2.2.2. The shoreline.

4.9.2.2.3. Plywood or its equivalent.

4.9.2.3. When working in or along a waterway, arrange encroachment permission for access through entities having jurisdiction, which may include: Port Authority, Fish and Game, Port Police, Homeland Security, Coast Guard, and Harbor Patrol.

4.9.2.4. Flood control channels may need special notification and permission.

4.9.2.5. While operating a motorized watercraft, ensure that no trash or debris are discharged in to the water.

4.9.2.6. If there is an accidental fuel or oil discharge from the boat, notify Environmental Services immediately.

4.9.2.7. Consider the options or combination of options listed in Table 4 to select an appropriate survey technique for a waterway according to its characteristics. See Table 4.

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Table 4: Waterway Access Options

Width of Waterway	Depth	Watercraft	Instrument	Technique Options
Less than 100ft	All	None	RMLD	Shore-to-Shore
				Shore-to-Target
Greater than 100ft	Less than 30"	Waders or flat-bottom push boat	RMLD	Waders or watercraft-to-target
				Waders or watercraft-to-shore
	Greater than 30" with limited launch ramp access	Non-Motorized watercraft (canoe, kayak, etc.)	RMLD	Watercraft to target
				Watercraft to shore
				Watercraft to watercraft
	Greater than 30" with launch ramp access	Motorized Boat	RMLD	Watercraft to target
				Watercraft to shore
				Watercraft to watercraft

4.9.2.8. The following conditions must be met to perform a waterway leak survey:

4.9.2.8.1. Wind speed must be 15 miles per hour (mph) or less.

4.9.2.8.2. Watercraft speed must be 3.9 knots (4.5 mph) or less.

4.9.2.8.3. Water must be still or in slack tide (consult local tide and current tables)

4.9.2.8.4. If the pipeline is in a location where the water is in constant flow and does not have times when it is still or in slack tide, then perform the following tasks when performing the survey:

4.9.2.8.5. Give consideration to the current direction and speed.

4.9.2.8.6. Perform multiple survey passes from the pipeline crossing to downstream of the pipeline for the distance gas is anticipated to drift during a rise in the water.

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4.9.2.9. Conform to the following constraints when performing all leak surveys:

4.9.2.9.1. Maintain the height of an RMLD to the waterline at 6 ft. or less. See Figure 1.

4.9.2.9.2. Maintain the height of a laser on a background target to the waterline at a minimum of 12 inches. But not more than 24 inches. See Figure 1.

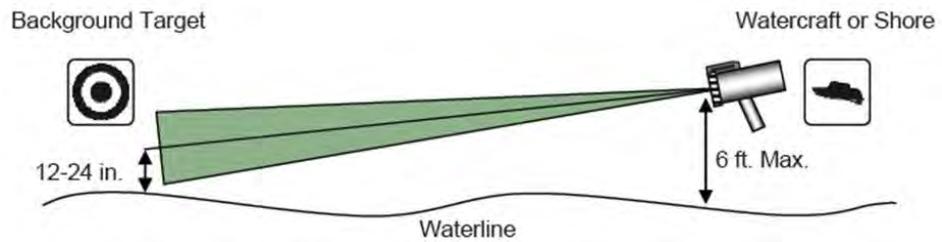


FIGURE 1

4.9.2.9.3. Proceed to the section identified below that is appropriate for the width of the waterway

4.9.3. Leak Surveying Waterways Less Than 100 Feet Wide

4.9.3.1. Perform the leak survey using an RMLD from shore to shore OR shore to a background target. See Figure 2

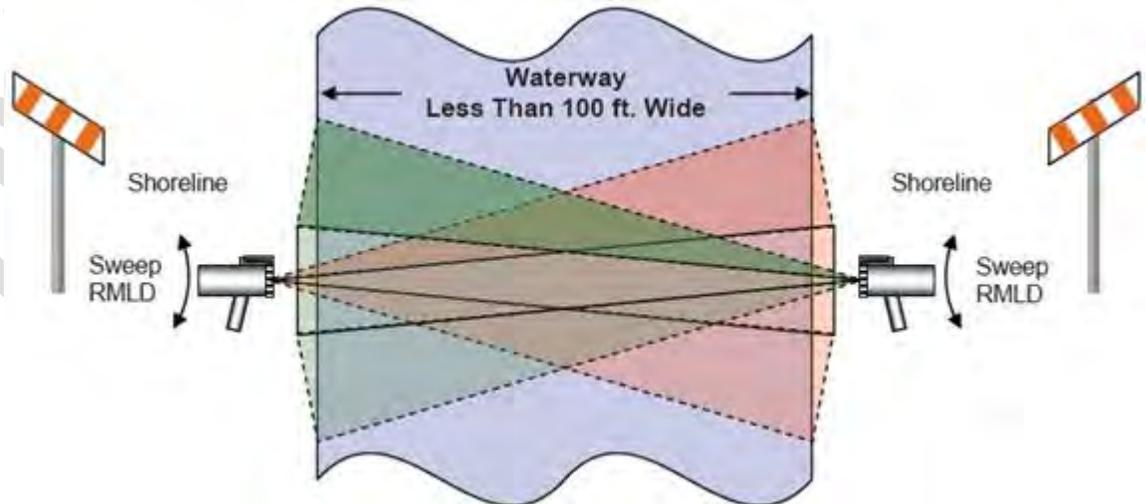


FIGURE 2

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NOTE: As illustrated in FIGURE 2, if the shoreline is flat and the background reflection is not possible, a second person must hold a background target, as described in section 4.9.2.2

4.9.4. Leak Surveying Waterways 100 to 120 Feet wide.

4.9.4.1. Perform leak survey using an RMLD from a watercraft in the waterway to the shoreline OR from a watercraft in the waterway to a background target 80 ft. away from the watercraft. See Figure 3.

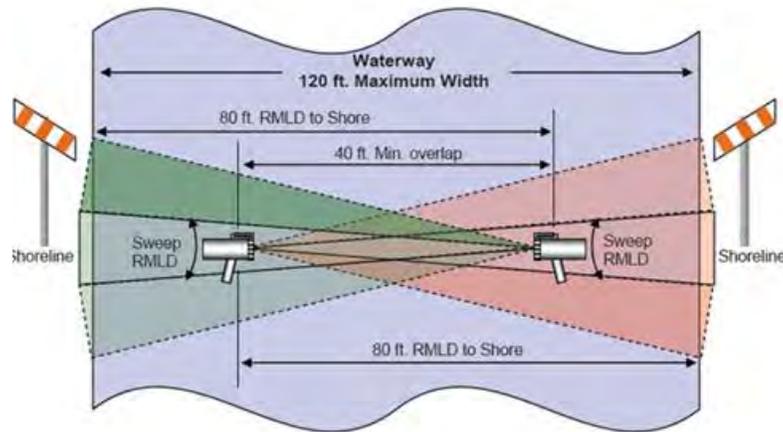


FIGURE 3

4.9.5. Leak Surveying Waterways Greater Than 120 Feet Wide

NOTE: It may be efficient to have two surveyors survey simultaneously from watercraft to watercraft.

4.9.5.1. Perform a leak survey using an RMLD from watercraft to watercraft or watercraft to a background target parallel to the pipeline (with the RMLD laser beams perpendicular to the pipeline being surveyed), adhering to the following criteria:

4.9.5.2. Maintain a minimum of 40 ft. AND a maximum of 80 ft. between the two watercrafts or the watercraft and the background target.

4.9.5.3. Overlap survey laser beams by a minimum of 40 ft. See Figure 4

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4.9.5.4. IF only one RMLD is used, THEN perform two survey passes, one in each direction, overlapping the areas covered by the laser beams by a minimum of 40 ft. See Figure 4.

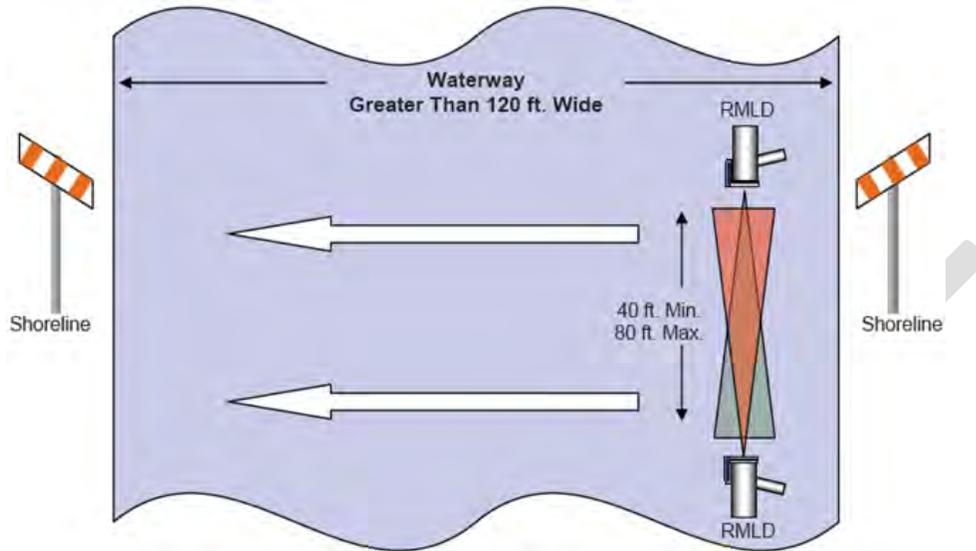


FIGURE 4

4.9.5.5. Complete the survey to the shoreline using an RMLD from watercraft 80 ft. or closer to the shoreline or a background target. See Figure 5.

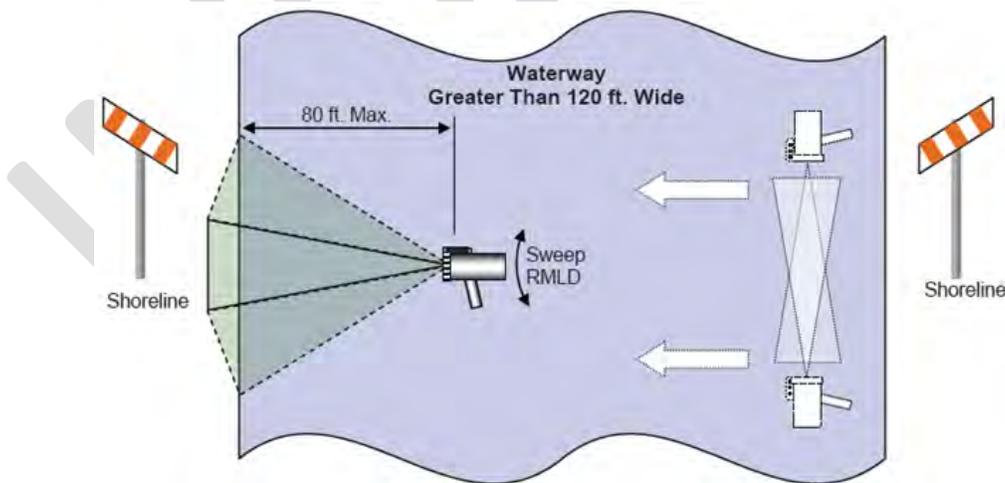


FIGURE 5

4.10. BUSINESS DISTRICTS

- 4.10.1. A business districts is an area that extends 100 feet from the property line of a parcel of property that has been identified as a significant commercial gathering point, a school, a hospital, a church or is a place where inhabitants have limited mobility.
- 4.10.2. Leak survey any distribution mains and associated services that have been identified as being within a business districts at the frequency established per Table 1.
- 4.10.3. The procedure for determining the business district is detailed in [GS 223.0102](#), *Updating of Leak Survey Maps*.
- 4.10.4. If during the survey, the leak surveyor identifies land uses that could potentially trigger a business district determination that is not currently depicted upon the leak survey map; they should identify this location for additional evaluation. The surveyor should document as follows:
- 4.10.4.1. The surveyor should circle the land parcel that potentially has triggered the business district and denote the following on the map cover sheet:
- 4.10.4.2. Select the checkbox identifying a potential business district was identified.
- 4.10.4.3. In the Comment Section of the Map Coversheet, describe the land use of the parcel that should be evaluated for meeting the business district designation (i.e. business, hospital, school, church, a significant commercial gathering point).
- 4.10.4.4. Return the completed survey map and comments to Asset Maintenance & Inspection for processing.

4.11. ABNORMAL OPERATING CONDITIONS

- 4.12. Issue orders for investigation and correction when any abnormal conditions (see GS167.0100, “*Operator Qualification Program*”, Appendix B, ABNORMAL OPERATING CONDITIONS) or when the following conditions, but not limited to, are encountered:
- 4.12.1. Meters in prohibited or hazardous meter locations, damaged, or corroded meter sets and meters buried in earth or paving.
- 4.12.2. Regulators in confined areas not vented to a safe location.

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- 4.12.3. Broken or missing curb meter vault or curb valve lids.
- 4.12.4. Service cocks not readily accessible or otherwise inoperable.
- 4.12.5. Pipe (including services) having buildings constructed over them.
- 4.12.6. Pipe (including services) that are endangered by foreign construction.
- 4.12.7. Curb valves not readily accessible on services to schools, hospitals or churches.
- 4.12.8. Exposed piping showing evidence of atmospheric corrosion, chemical corrosion and other conditions that warrant concern.
- 4.12.9. Stress on exposed piping facilities as a result of earth movement or other causes.
- 4.12.10. Missing, broken and damaged casing vents.

4.13. EVALUATION OF LEAKAGE

- 4.13.1. The **responsible employee or supervisor** reviews all leak indications found and assigns an appropriate leakage priority classification based on potential hazard. See [GS 223.0125](#), *Leakage Classification and Mitigation Schedules*.
- 4.13.2. Employees shall notify Supervision of all Leak indications detected over buried pipelines with an MAOP of 20% SMYS or more, (excluding leak indications on buried valves/fittings identified by indications at the casing), See [GS 184.0245](#), *Leak Investigation*.
 - 4.13.2.1. Further Leak investigation will require pressure monitoring and reduction as prescribed in [GS 184.0245](#), *Leak Investigation*.
- 4.13.3. Any leak indication that is investigated and presumed to be from another SoCalGas Business Unit (i.e. Transmission, Distribution or Storage) should be reported to the appropriate business unit in a timely manner.
- 4.13.4. When a Gas **Transmission District** or **Storage Field** detects leakage on a **Distribution Region** facility, obtain the **Region's** appropriate leak order number. Record the number on [Form 677-1](#), *Pipeline Condition and Maintenance Report*, and on the leak survey inspection record.
- 4.13.5. When a **Distribution Region** detects leakage on a **Gas Transmission District** or **Storage Field facility**, the appropriate **Gas Transmission District** or **Storage Field** is contacted. The Gas Transmission District or

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Storage Field provides the reporting Region with the applicable [Form 677-1](#) number.

- 4.13.6. The survey person will confirm any leak indication with a combustible gas indicator (CGI); see [GS 107.0287](#), *GMI Gasurveyor – Combustible Gas Indicator (CGI)* and [GS 107.0294](#), *DP-IR Heath Detecto Pak-Infrared®*.
- 4.13.7. To code a leak when the DP-IR Unit is used as a CGI the “sustained” read must be at a detectable level, meaning the read must be 4500 PPM or more with the DP-IR or the GMI Gasurveyor – Combustible Gas Indicator (CGI).
- 4.13.8. If the leak indication is located under street or paving, a hole must be drilled to take the read.
- 4.13.9. Barholes are not required to code a leak when:
 - 4.13.9.1. Indications are detected over buried pipelines with an MAOP of 20% SMYS or more in remote areas **AND**
 - 4.13.9.2. Where two approved leak survey instruments are utilized to verify leak indications and extent of leak indications.
- 4.14. When leak indications are suspected to be from field or swamp gas per [GS 184.0220](#), *Field Gas*, the responsible supervisor contacts the Engineering Analysis Center (EAC).
- 4.15. Leak indications found in small gas associated substructures, such as but not limited to small curb meter boxes or gas valve boxes / valve casings and **not** in the surrounding soil must be reported. Issue an order (form 4040) to code the leak in the small gas associated substructure:
 - 4.15.1. Code leaks accordingly to indications and situations that are found per [GS 223.0125](#), *Leak Classification and Mitigation*.
- 4.16. **REPORTING**
 - 4.16.1. When a suspected safety-related condition is found, report it to the immediate supervisor the same day the condition is discovered
 - 4.16.2. Report all leaks and corrosion on **DOT-T Transmission lines** as outlined in [GS 183.06](#), “*Region Reports of Safety-Related Pipeline Conditions.*”

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4.16.3. To ensure a safe response, communicate emergency incident as outlined in [GS 183.03](#), *Field Guidelines – Emergency Incident Distribution / Customer Service* or [GS 183.0110](#), *Field Procedures- Emergency Incidents- Transmission*.

5. EXCEPTION PROCEDURE

See [GS 182.0004](#), *Exception Procedure for Company Operations Standards*.

- 5.1. An exception to this standard shall be considered only after practical solutions have been exhausted. Safety issues shall be given primary consideration, while adhering to governing codes before an approval of an exception is granted.
- 5.2. An exception from a standard shall not be allowed unless [GS 182.0004](#), *Exception Procedure for Company Operations Standards* is followed and approval is given by the Responsible Person (RP) for the standard or by someone in that person's organization that has been granted authority, and by others as required by 182.0004, and if specified in the standard from which the exception is requested.

6. OPERATOR QUALIFICATION COVERED TASKS

(See [GS 167.0100](#), Operator Qualification Program, Appendix A, Covered Task List)

Task 09.01. – 49 CFR 192.706 – Performing leakage surveys: transmission lines

Task 09.02 - 49 CFR 192.723 – Performing leakage surveys: distribution systems

Task 02.13 - 49 CFR 192.481 – Monitoring for atmospheric corrosion

7. RECORDS

7.1. Gas Transmission District and Storage Operations

- 7.1.1. All leaks shall be recorded the same day the leaks are detected
- 7.1.2. Document all leak indications and leak repairs on [Form 677-1](#), Pipeline Condition and Maintenance Report (Transmission and Storage).
- 7.1.3. Schedule, track, and document all routine leakage surveys in an approved computerized maintenance management system (MAXIMO).

7.2. Distribution Regions

- 7.2.1. Documentation of the Leak Survey
 - 7.2.1.1. All leaks shall be recorded the same day the leaks are detected

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- 7.2.1.2. Leak surveyor will document the completion of a leak survey on the leak survey order in the Mobile Data Terminal (MDT).
- 7.2.1.3. The leak surveyor performing the leak survey is also provided with maps of the areas to be surveyed. The Maps used for survey will depict pipeline location to be surveyed and the surrounding streets.
- 7.2.1.4. The leak surveyor is required to bracket the completed area(s) they surveyed for that day on the map using a blue pen. It is also required for them to include their initials and the date the survey was performed on each pipeline segment.
- 7.2.1.5. All below ground leaks are noted in red and marked with an “X”, tallied on the Leak Survey Map Embedded Cover Sheet and:
 - 7.2.1.5.1. Existing leaks are verified using the “Shop Papers” under the “Attachments” tab within the Leak Survey Order. Once verified, existing leaks are identified with the Equipment number
 - 7.2.1.5.2. Existing Code 2 and Code 3 (Steel and Plastic) leak indications are displayed on the Leak Survey Map and identified with the Equipment number.
 - 7.2.1.5.2.1. Leak indications detected over existing leaks within the path of survey are recorded as described in section 7.2.1.5.

NOTE: A mark is not required when leak indications are **NOT** detected over existing leaks that are displayed on the Leak Survey Map.

- 7.2.1.6. If leakage spread is twenty (20) feet or more use dotted red line to indicate spread on map.
- 7.2.2. Documentation of Leak Investigation
 - 7.2.2.1. Leak investigations are documented on a leak investigation order (Form 4030) which available on the MDT.
 - 7.2.2.2. Form 4030 is used with the Maintenance Activity Type of “Recheck Leak” for recheck of underground leakage after repair.

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- 7.2.2.3. Report all leaks and corrosion on transmission lines as outlined in [GS 183.06](#), *Region Reports of Safety-Related Pipeline Conditions*.

7.3. RECORDS RETENTION

- 7.4. Records covering leakage surveys, leaks discovered, and repairs made on distribution pipelines are documented using SAP and maintained for the life of the pipeline plus six years.
- 7.5. Records covering leakage surveys, leaks discovered, and repairs made on transmission pipelines are documented using an approved computerized maintenance management system (e. g., MAXIMO or SAP) and filed by the appropriate **Gas Transmission District, Storage Field, or Distribution Region**, and must be retained per Records Management Retention Schedule. See Records Retention Standards on Sempra Net, <http://home.sempranet.com/rm/>.

- 7.5.1. In addition to the other recordkeeping requirements of these rules, each Operator shall maintain the following records for transmission lines for the periods specified:
- A. The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipeline remains in service or there is no longer pipe within the system of the same manufacturer, size and / or vintage as the pipeline on which repairs are made, whichever, is longer.
 - B. The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 75 years. Repairs or findings of easement encroachments, generated by patrols, surveys, inspections, or tests required by subparts L and M of 49 CFR Part 192 must be retained in accordance with paragraph (c) of this section.
 - C. A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 75 years.

8. APPENDICES

- 8.1. N/A



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Leakage Surveys	SCG:	223.0100
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NOTE: Do not alter or add any content from this page down; the following content is automatically generated.

Brief: There were no changes to the duties performed. Policy was revised to better explain the requirements when leak indications are detected on a buried pipeline with an MAOP of 20% SMYS or more. Revisions made to provide guidance when investigating leak indication near intersecting and/or parallel pipelines. Provided guidelines for performing leakage surveys due to lightning strikes. Hyperlinks were updated. Minor word changes throughout document for clarity. Reformatted to add a new section 5, Exception Procedures. Removed Operator Qualification Task 02.13, Monitoring for Atmospheric corrosion. reference from GS.

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Research & Development Templates

Best Practice Addressed	R&D Project	Subject
16	16	Special Leak Surveys & Predictive Methodologies
17	17-1	Aerial Methane Detection
17	17-2	Sub-Surface Modeling
17	17-3	Evaluation of New Instruments for Leak Detection, Localization, and Speciation
18	18	Evaluation of Stationary Methane Detectors
20	20a-1	Develop Distribution Mass-Balance Leak Detection and Quantification Methodology
20	20a-2	Develop Improved Measurement Methods for Buried Leaks
20	20a-3	Develop Company Specific Emission Factors
20	20a-4	Model Leak Growth Rates from Polyethylene Plastic Piping Slow-Crack Growth Failures
20	20a-5	Quantification of Through-Valve Leakage on Large Compressor Valves
20	20b	Geographic Emissions Tracking & Evaluation
22	22	Investigate Specifications, Tolerances and Sealing Compounds for Threaded Fittings
23	23-1	Evaluation of Technologies to Mitigate Vented Emissions and Gas Blowdowns
23	23-2	Evaluate Component Emission Reductions Opportunities
23	23-3	Alternative Fuel Substitution Strategy

**2020 Leak Abatement Plan R&D Summary #16
Special Leak Surveys & Predictive Methodologies**

1) BEST PRACTICE ADDRESSED

- Best Practice 16: R&D for Special Leak Surveys & Predictive Methodologies. Utilities shall utilize enhanced technologies, such as artificial intelligence, to predict and provide spatial analysis of leak threats near pipelines.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Evaluation of Special Leak Surveys & Predictive Methodologies.
 - Improve understanding of current factors that contribute to system leakage (such as pipeline materials and operating environment variables) that can be used to predict system leakage.
 - Emission reductions through predictive models and early leak detection.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to achieve emission reductions by evaluating different strategies for predictive spatial analysis of leakage threats. Predict and prevent system leakage by leveraging machine learning/artificial intelligence.
- Areas targeted

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

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
 - Gather input from subject matter experts
 - Develop models or algorithms
 - Conduct special field survey pilots to validate models

4) ANTICIPATED OR EXPECTED RESULTS

- Determine effective strategies to predict leakage threats.
Emission reductions through predictive models and early leak detection

**2020 Leak Abatement Plan R&D Summary #16
Special Leak Surveys & Predictive Methodologies**

5) EMISSIONS IMPACT

- SoCalGas anticipates emission reductions through predictive models and early leak detection; however, it is difficult to anticipate or estimate potential emissions reductions.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

- **CEC- NATURAL GAS PIPELINE INTEGRITY SAFETY AND INTEGRITY MANAGEMENT (GFO-15-506) AND CEC-STORAGE RESEARCH PROJECT (GFO-16-508)**

- Anticipated End Date: Q4 2020

b. PROPOSED PROJECTS

- Develop leak prediction models leveraging prior and on-going project related to evaluation and development of leakage risk models and predictive methodologies, such as projects in correlation to leak rates as associated with steel and PE piping leakage:
 - Tapping Tee Cap
 - Tree Root Damage
 - Rocky Soil Threats
 - Leak migration models
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q1 2023

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

a. CURRENT PROJECTS

- Projects related to this Best Practice that are currently in progress are scheduled to be completed by the end of 2020.

b. PROPOSED PROJECTS

- Predictive Methodologies Projects
 - Gather input from subject matter experts
 - Data gathered from subject matter expert is used to characterize or identify areas of interest.
 - Develop models or algorithms

**2020 Leak Abatement Plan R&D Summary #16
Special Leak Surveys & Predictive Methodologies**

- Data gathered during inspection of leak damage reports and special leak surveys will be used in model development and evaluation of machine learning/artificial intelligence.
- Data output from model or algorithm will be utilized to schedule/identify the special field survey pilots.
- Conduct special field survey pilots to validate models.
 - Data output from special field surveys are used by machine learning to update models.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$288,181	\$340,800

SDG&E	2021	2022
	\$25,936	\$30,672

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

SoCalGas	Total Loaded Costs
	\$774,129

SDG&E	Total Loaded Costs
	\$69,672

**2020 Leak Abatement Plan R&D Summary #16
Special Leak Surveys & Predictive Methodologies**

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

Tools for Predicting Gas Migration and Mitigating its Occurrence/Consequence. (n.d.).

Retrieved from <https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=748>

<https://ww2.energy.ca.gov/2017publications/CEC-500-2017-036/CEC-500-2017-036.pdf>

**2020 Leak Abatement Plan R&D Summary #17-1
Aerial Methane Detection**

1) BEST PRACTICE ADDRESSED

- 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.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Aerial Leak Detection and Quantification Technologies.
- Reduce emissions and improve efficiencies by detecting, differentiating, and rapidly responding to large leaks.
- Pilot studies to validate actual costs and leak detection, pin-pointing, and system capabilities.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to continue advancing aerial emissions detection technologies and to better understand actual capabilities of new technologies and methods available for detecting and locating methane emissions by aerial means (Satellite, Manned and Unmanned Aircraft) and the relative benefits, shortcomings, costs and short-notice availability of each application.
- 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

- The R&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
 - Facilitate demonstrations of unmanned vehicles, methane sensors, and/or payload components (cameras, instrumentation, black box) for the purpose of determining capability and applicability to the gas infrastructure in both SCG and SDGE.
 - b) Laboratory Evaluation
 - Establish baseline performance for sensors and other quantification instruments.
 - c) Comparative evaluation to manufacturer specifications.
 - Evaluate the sensors and other quantification instruments to Company requirements for intended applications.

2020 Leak Abatement Plan R&D Summary #17-1

Aerial Methane Detection

- d) Simulated Field Evaluation (Controlled Environment)
 - Evaluate each prototype system, sUAS with payload, in a simulated field environment utilizing controlled natural gas releases. Compare against Company's specifications for the intended application, and test for repeatability.
- e) Field Demonstrations
 - Demonstrate aerial systems in actual field environments. May include controlled natural gas releases and evaluation for false positives and false negatives.
- f) Pilot Study
 - Conduct pilot studies of viable aerial technologies for specific intended applications. Evaluate implementation costs and calculate potential emissions reduction.

4) ANTICIPATED OR EXPECTED RESULTS

- Using acquired understanding, determine the usefulness of each application to both small scale and large-scale needs in the practical applications of gas utility routine or emergency operations.
- Using acquired understanding, 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.

5) EMISSIONS IMPACT

- It is difficult to estimate the reduction in emissions that could result from applying aerial methodologies. Aerial technologies facilitate more rapid deployment possibilities and access to locations restricted from the ground and will likely result in better leak detection and reduced duration between detection and repair.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS (2018 Compliance Plan)

1. NYSEARCH- sUAS Technology (M2014-001)
 - Project Close Out: Q1 2020
2. Aerial (sUAS) Leak Detection Research (SCG-2016-001)

Prior and current research and demonstrations will be leveraged to support aerial leak detection. This includes ongoing development of payload systems such as sensor platforms and software, Gas Mapping LiDAR™ systems and image recognition technologies, and sUAS technology

 - Anticipated Project Close Out: Q4 2020
3. Aerial (sUAS) Leak Detection Research Projects (BP17 Z-3)

This SoCalGas project has been executed in parallel with, and been used in support of, the progressive development of drone and sensor instrument by the respective manufacturers. Specific to this project are the Pergam sensor and the Microdrones MD4-1000 sUAS, which were selected as the best

2020 Leak Abatement Plan R&D Summary #17-1
Aerial Methane Detection

candidates at the time out of several sensor and sUAS combinations. (See video in References). The methane concentration data collected by the Pergam sensor (~100 ft height limit) coupled with GPS flight data has been demonstrated to provide locations of elevated methane levels that can be utilized for leak detection and leak localization. The system can closely inspect pipelines, bridges, and other facilities that may be difficult to access. Develop sensor platform for UAS deployment and associated software for data postprocessing to perform emission quantification (BP17 Z-3)

- Anticipated End Date: Q4 2020
- 4. Aerial (Manned) Leak Detection, Pin-Pointing of Emission Source, and Quantification using Bridger Photonics Gas Mapping LiDAR™ system.
 - Anticipated End Date: Q4 2020

b. PROPOSED PROJECTS

1. Evaluate Optical Gas Imaging (OGI) on UAV using Southwest Research Institute image recognition software.
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2021
2. Satellite methane detection technologies for super emitters (appx. 100+ cfh)
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2022
3. Evaluate various manned aircraft systems to detect large leaks (appx. 10+ cfh) system-wide
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

CURRENT and PROPOSED PROJECTS:

- Manufacturer Demonstration
- Data gathered during manufacturer demonstration is used to identify potential capabilities that can be leveraged for Company specific applications.
- Laboratory Evaluation
- If possible, data gathered during laboratory evaluation is used to demonstrate capability of sensors and instruments for intended applications. (Go/No-Go Decision).
- Use results of laboratory data to guide simulated field-testing plan.

**2020 Leak Abatement Plan R&D Summary #17-1
Aerial Methane Detection**

- Simulated Field Evaluation (Controlled Environment)
- Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, to develop Standard Operating Procedures, and provide feedback to manufacturers for required enhancements to performance.
- Data gathered during simulated field evaluation will be used to demonstrate that the sUAS system can meet Company specifications and FAA regulations. (Go/No-Go Decision)
- Use 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.
- Evaluate Cost of Implementation
- Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
- Pilot Study
- Data gathered during pilot studies will be used to demonstrate the capability of the sUAS system for intended applications, and that the system can meet Company specifications and FAA regulations. (Go/No-Go Decision)
- Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision)

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$550,346	\$551,294

SDG&E	2021	2022
	\$49,531	\$49,616

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

<u>SoCalGas</u>	Total Loaded Costs
	\$1,356,046

<u>SDG&E</u>	Total Loaded Costs
	\$122,044

2020 Leak Abatement Plan R&D Summary #17-1
Aerial Methane Detection

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

- a. NYSEARCH 2014-001 Project Report
- b. Microdrone Video: <https://www.youtube.com/watch?v=fSveg51lcDo>
- c. UgCS Data Logger: <https://www.ugcs.com/news-entry/detecting-a-methane-leak-faster-and-more-safely>
- d. UgCS Case Study: <https://industrial.ugcs.com/methane-detector#case-studies>
- e. Percepto: <https://percepto.co/oil-gas-drones/>
- f. Seek-Ops: <https://www.seekops.com/>
- g. Satelytics: www.satelytics.com
- h. Kairos: <http://kairosaerospace.com/methane-detection/>
- i. Ball Aerospace:
https://www.ball.com/aerospace/Aerospace/media/Aerospace/Downloads/D3242-Methane-Monitor_0518.pdf?ext=.pdf
- j. LASEN: <http://www.lasen.com/technology.aspx>
- k. JPL: <https://www.jpl.nasa.gov/news/news.php?feature=6192>
- l. **PRCI Multi-sensor platform: Report Title:**
PR-271-173903-R01 Evaluation of Current ROW Threat Monitoring, Application & Analysis Technology – website:
<https://www.prci.org/Research/SurveillanceOperationsMonitoring/SOMProjects/ROW-6-2/56648/171730.aspx>
Title:
PR-680-183907-R01 Use of Aerial LiDAR for Geohazard Assessment
Website:
<https://www.prci.org/Research/SurveillanceOperationsMonitoring/SOMProjects/GHZ-1-01/101481/169042.aspx>

**2020 Leak Abatement Plan RD&D Objective Summary #17-2
Sub-Surface Methane Modeling**

1) BEST PRACTICE ADDRESSED

- 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.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Sub-Surface Methane Modeling
 - Improve understanding natural gas migration in system territory operating environments including soil types to gain an understanding of leakage migration threats to pipelines and possibly anticipate hazardous operating conditions to better predict hazardous leaks.
 - Understanding of sub-surface methane behavior may result in better understanding of leak behavior and validation of current practices for below-ground methane threshold(s), resulting in increased leak detection efficiency.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to study the sub-surface methane environment and determine factors that contribute to leak migration. Understanding of these factors will be used to develop numerical models to predict gas migration behavior below ground.
- The research objective is also to determine the appropriate below-ground methane concentration threshold(s) that should trigger creation of leak record and investigation.
- Areas targeted

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

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

2020 Leak Abatement Plan RD&D Objective Summary #17-2 Sub-Surface Methane Modeling

- The R&D approach to meet the objective will involve a series of planned evaluations, that include one or more of the following:
 - a) Collect Leak Response Survey Data
 - a. Leak data and borehole samples
 - b) Analytic Method Development
 - a. Simultaneous and iterative analysis of:
 - i. Statistical Analysis of Leak Response Survey Data
 - ii. Controlled Field Experiments
 - iii. Numerical Modeling
 - iv. Develop Analytic Tool
 - c) Field Validation of Analytic Method (PHMSA)
 - d) Field Validation of Analytic Method (Company)
 - e) Evaluate the methodologies in a Company specific field environment.

4) ANTICIPATED OR EXPECTED RESULTS

- Using acquired understanding, determine appropriate below-ground methane concentration threshold(s) that should trigger creation of leak record and investigation.
- Using acquired understanding, enable pipeline operators to determine if below-ground methane emissions are due to a leak from the natural gas piping system.

5) EMISSIONS IMPACT

- 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 increases operational efficiency and resulting in overall shorter leak duration and emissions reduction.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

- Tools for Predicting Gas Migration and Mitigating its Occurrence/Consequence (PHMSA - #748).

This project is managed by PHMSA with Academia as the performer and includes involvement and participation of selected Utilities. The project includes data collection and analysis plans for each stage of the R&D approach.

- Actual Start Date: Q4 2018

2020 Leak Abatement Plan RD&D Objective Summary #17-2
Sub-Surface Methane Modeling

- Anticipated End Date: Q2 2021
- Below Ground Methane "Background" Concentration Study Research Projects (SoCal Gas).
 - Actual Start Date: Q4 2019
 - Anticipated End Date: Q2 2021

b. PROPOSED PROJECTS

- Field Validations of Analytical Model – Company Specific
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q3 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

- Field Validations of Analytical Model – Company Specific
 - Leak Survey
 - Data gathered during leak survey is used to roughly confirm output of analytical tool.
 - Map Surface Concentrations and Flux
 - A grid of surface concentration measurements is used to demonstrate capability of analytical tool and provide feedback to developers for required enhancements to performance.
 - Surface flux measurements (using Hi Flow Sampler™ or equivalent) will be used to demonstrate capability of analytical tool and provide feedback to developers for required enhancements to performance.
 - Soil Measurements
 - Measurements of the gas concentration in the soil (barhole) will be used to demonstrate capability of analytical tool and provide feedback to developers for required enhancements to performance.
 - Excavation and Direct Measurement
 - Direct measurement of the emission rate, after excavation, (using Hi Flow Sampler™ or equivalent) will be used to demonstrate capability of analytical tool and provide feedback to developers for required enhancements to performance
 - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision for further Field Validations).
 - Evaluate Cost of Field Validation
 - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision for further Field Validations)

**2020 Leak Abatement Plan RD&D Objective Summary #17-2
Sub-Surface Methane Modeling**

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$250,157	\$125,294

SDG&E	2021	2022
	\$22,514	\$11,276

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

SoCalGas	Total Loaded Costs
	\$462,408

SDG&E	Total Loaded Costs
	\$41,617

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

- Tools for Predicting Gas Migration and Mitigating its Occurrence/Consequence:
<https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=748>

2020 Leak Abatement Plan R&D Objective Summary #17-3
Evaluation of New Instruments for Leak Detection, Localization, and Speciation

1) BEST PRACTICE ADDRESSED

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

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Evaluation of New Instruments for Leak Detection, Localization, and Speciation.
- Improve efficiency and reduce cost of operation.
- Reduce emissions by improving detection efficiency.
- Conduct Pilot studies to be initiated based on results of instrument evaluations.
 Pilot studies will provide basis for implementation cost and emissions reductions estimates.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- This research objective is to identify instruments and/or methods to improve the efficiency and output of the leak detection 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.
- Areas targeted

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

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
 - 1) Manufacturer Demonstration
 - 2) Laboratory Evaluation
 - 3) Simulated Field Evaluation (Controlled Environment)
- Facilitate demonstrations by manufacturers of new technologies, methods, and/or practices for leak detection, localization, and speciation.
- Establish baseline performance for instruments that are evaluated.
- Comparative evaluation to manufacturer specifications and currently approved devices.
- Evaluate the instruments to Company requirements for intended applications.
- Evaluate instruments and technologies in a simulated field environment utilizing controlled natural gas releases.
- Compare to currently approved devices, practices, and/or procedures.

2020 Leak Abatement Plan R&D Objective Summary #17-3
Evaluation of New Instruments for Leak Detection, Localization, and Speciation

4) Pilot Study

- Obtain and evaluate multiple devices against Company's specifications for the intended application, and test for repeatability.
- Evaluate instruments and technologies in an actual field environment, including controlled natural gas releases.
- Compare to currently approved devices, practices, and/or procedures.

4) ANTICIPATED OR EXPECTED RESULTS

- Identify more accurate, precise, or reliable instruments and methods for leak detection, localization, and speciation processes.

5) EMISSIONS IMPACT

- Reduce emissions by improving detection, leak localization and quantification efficiency. Leaks detected and repaired earlier in the lifecycle will result in a reduction of emissions, leak detection and localization efficiency will reduce operational costs.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS (2018 Compliance Plan)

- Back Pack & Handheld Methane Detection Tools (Sensor) & Systems Research Projects (a.k.a. Next Generation Walking Leak Survey) (BP 17 AC-2)

Exploratory work has been completed by the Company to evaluate the addition of open-path laser analyzers to enhance the Company approved walking leak survey technology, DPIR. Exploratory work in the laboratory, simulated field conditions, and actual field scenarios has been executed. Ongoing work includes similar exploratory investigations of a variety of PPB-sensitive laser analyzers used to monitor atmospheric methane concentrations in addition to traditional methods for inspecting ground level and below-ground methane levels based on the Company approved survey methodologies.

- Actual Start Date: Q1 2019
- Anticipated End Date: Q1 2021

- NYSEARCH T-784 First Pass Leak Detection Optimization:
Optimize Walking Leak Survey for buried Distribution pipelines (performed on a single pass) using instrumentation and data acquisition techniques to maximize the rate of leak detection for traditional leak survey methods. A second goal of this project is to determine what improvements can be achieved using an integrated technology approach between traditional instruments performing drawn samples from the ground surface with part-per-million sensitivity combined with atmospheric monitoring instruments with parts-per-billion sensitivity.

- Anticipated End Date: Q4 2020

2020 Leak Abatement Plan R&D Objective Summary #17-3
Evaluation of New Instruments for Leak Detection, Localization, and Speciation

- Integrate Mobile Methane Mapping w/Mobile Leak Survey Research Project: Evaluate possibility of integrating GIS and wind (speed & 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.

- Anticipated End Date: Q4 2020

- Evaluate Aeris MIRA PICO Responder™ advanced mobile leak detection system:

The MIRA PICO analyzer with 1 PPB sensitivity for Methane and 0.5 PPB sensitivity for Ethane. System includes software application and analytics for visual integration of emissions detection with wind and GPS data, plus potential ability for emission source speciation to distinguish petrogenic sources from common biogenic and vehicle emission sources.

- Anticipated End Date: Q4 2020

- Optical Gas Imaging (OGI) Cameras and associated leak quantification algorithms:

The development or demonstration of leak quantification using OGI or estimation of leak size based on IR camera imaging and algorithms could provide rapid estimates of the size of leaks and result in better prioritization of leak repairs (i.e., repair largest leaks first and reduce emissions). In 2019 SoCalGas investigated two currently available and viable IR camera algorithms to categorize leak rates and determined that neither technology is suitable for categorization of underground pipeline leaks at that time.

- Actual Start Date: Q4 2018
- Anticipated End Date: Q1 2020

b. PROPOSED PROJECTS

- Evaluate new leak detection, localization, and speciation technologies.
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2022

2020 Leak Abatement Plan R&D Objective Summary #17-3
Evaluation of New Instruments for Leak Detection, Localization, and Speciation

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

a. CURRENT PROJECTS

- Back Pack & Handheld Methane Detection Tools (Sensor) & Systems Research Projects (a.k.a. Next Generation Walking Leak Survey) (BP 17 AC-2).
 1. Manufacturer Demonstration
 - Data gathered during manufacturer demonstration is used to identify potential capabilities that can be leveraged for Company leak detection, speciation, and localization.
 2. Laboratory Evaluation
 - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Use results of laboratory data to guide simulated field-testing plan.
 3. Evaluate Cost of Implementation
 - Estimate cost to conduct simulated field evaluation.
 - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
 4. Simulated Field Evaluation (Controlled Environment)
 - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Use 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).
 5. Pilot Study
 - Verify capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).
- NYSEARCH T-784 First Pass Leak Detection Optimization
 1. Solicit information from funding members as to existing practices for leak survey and for combining techniques

2020 Leak Abatement Plan R&D Objective Summary #17-3
Evaluation of New Instruments for Leak Detection, Localization, and Speciation

- Select Instrumentation and Technique Combinations
- 2. Model Leak Detection Comparative Techniques. Use statistical Design of Experiments (DOE) to define data collection parameters and evaluate test results.
 - Perform Field Testing
 - Conduct Statistical Analysis.

b. PROPOSED PROJECTS

1. Manufacturer Demonstration
 - Data gathered during manufacturer demonstration is used to identify potential capabilities that can be leveraged for Company leak detection, speciation, and localization.
2. Laboratory Evaluation
 - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Use results of laboratory data to guide simulated field-testing plan.
3. Evaluate Cost of Implementation
 - Estimate cost to conduct simulated field evaluation.
 - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
4. Simulated Field Evaluation (Controlled Environment)
 - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Use 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).
5. Pilot Study
 - Verify capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision)

2020 Leak Abatement Plan R&D Objective Summary #17-3
Evaluation of New Instruments for Leak Detection, Localization, and Speciation

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$960,604	\$851,999

SDG&E	2021	2022
	\$86,454	\$76,680

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

<u>SoCalGas</u>	Total Loaded Costs
	\$2,231,417

<u>SDG&E</u>	Total Loaded Costs
Methane Detection Sensor & Systems Research Project (handheld and mobile devices)	\$200,828

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

- Southern California Gas Company – Pico Rivera. “Southern California Gas Company’s Verification Study of the Methane Mapping of Four California Cities by the Environmental Defense Fund and Colorado State University” Southern California Gas Company. Southern California Gas Company, August 2016. https://www.socalgas.com/regulatory/documents/r-15-01-008/EDF_4-Cities_Methane_Mapping_Report_Final_081916.pdf
- <https://primis.phmsa.dot.gov/rd/mtgs/091118/Ed%20Newton.pdf>
- “Mobile Guard Advance Mobile Leak Detection.” <https://Heathus.com/Wp-Content/Uploads/MobileGuard.pdf>
- Leifer, I., and I. MacDonald. 2003. Dynamics of the gas flux from shallow gas hydrate deposits: Interaction between oily hydrate bubbles and the oceanic environment. Earth and Planetary Science Letters 210(3/4):411-424.
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- University of California - Santa Barbara. "Methane emissions higher than thought across much of U.S.." ScienceDaily. ScienceDaily, 15 May 2013. <www.sciencedaily.com/releases/2013/05/130515165021.htm>.

2020 Leak Abatement Plan R&D Objective Summary #17-3
Evaluation of New Instruments for Leak Detection, Localization, and Speciation

- “Improving Methane Emissions Estimates for Natural Gas Distribution Companies, Phase II - PE Pipes.” *OTD*, 23 Nov. 2013, https://www.otd-co.org/reports/Documents/710c_OTD-14-0001-Improving-Methane-Emission-Estimates-NG-Distribution-Companies-PE-Pipes-FinalReport.pdf. RKI HH Tech/Data sheet – Website.
- Aeris MIRA PICO Hand-Held and Mobile Leak Detection Systems (LDS) Responder™ Advanced Mobile LDS System
- <http://aerisensors.com/pico-series/>
- http://aerisensors.com/wp-content/uploads/2019/12/MIRA-Responder-LDS_191208_FINAL_quartz.pdf
- Pergam Technologies: <http://pergamusa.com/lmm/>

**2020 Leak Abatement Plan R&D Objective Summary #18
Evaluation of Stationary Methane Detectors**

1) BEST PRACTICE ADDRESSED

- 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.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Evaluation of Stationary Methane Detectors
- Reduce emissions by quicker leak detection and repair.
- Pilot studies to be initiated based on results of instrument evaluations. Pilot studies will validate actual costs and emissions reductions.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to develop and/or evaluate stationary methane sensors for early detection of leaks.
- 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

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
 - a) Manufacturer or Prototype Demonstration
 - Facilitate demonstrations of research prototypes or by manufacturers of methane sensors
 - b) Laboratory Evaluation
 - Establish baseline performance for sensors that are evaluated.

2020 Leak Abatement Plan R&D Objective Summary #18
Evaluation of Stationary Methane Detectors

- Comparative evaluation to manufacturer/prototype specifications and currently approved sensors.
- Evaluate the sensors to Company requirements for intended applications.
- c) Simulated Field Evaluation (Controlled Environment)
 - Evaluate sensors in a simulated field environment utilizing controlled natural gas releases.
 - Compare to currently approved sensors.
- d) Pilot Study
 - Obtain and evaluate multiple sensors of a single type against Company's specifications for the intended application, and test for repeatability.
 - Evaluate sensors in an actual field environment, including controlled natural gas releases.
 - Compare to currently approved sensors.
- Blind studies and validation of actual costs and emissions reductions

4) **ANTICIPATED OR EXPECTED RESULTS**

- Accurate assessment of the performance of stationary sensors enables field deployment leading to quicker leak detection and repair and emissions reductions.

5) **EMISSIONS IMPACT**

- The reduction and quick repair of leaks as detected by stationary sensors represents various size leaks at n as yet unknown quantity for various applications. Therefore, the emissions reduction cannot be estimated at this time.

6) **MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)**

a. CURRENT PROJECTS (2018 Compliance Plan)

- Stationary Methane Sensor Evaluation BP 18 AE-3.3 - complete

The Company executed an evaluation of stationary methane sensors under laboratory conditions and simulated field conditions. Sensors included three open path lasers and one closed path laser, capable of detection to 2ppm-m, and two-point sensors capable of detection to 1% and 2% LEL. Key findings included better understanding of specific use applications for the various sensors and sufficient information to select best performing sensors and/or eliminate certain candidates.

- Anticipated End Date: Q1 2020

2020 Leak Abatement Plan R&D Objective Summary #18 Evaluation of Stationary Methane Detectors

- Methane Sensors State-of-the-Art Investigation (OTD 7.16.f) BP 18 AE-2
This study provided a high-level review of the current state of the art in “point” methane sensors and how they are used in the utility industry. However, the project did not provide comprehensive quantitative data on sensor performance (accuracy, sensitivity/detection limit, methane or methane + ethane, repeatability/precision, range, survey speed, response time, passive or active sampling, etc.) in comparable engineering units.
 - Project close out: Q4 2019
- Residential Methane Detector (BP 18 AE-3.1 NYSEARCH M2010-002)
The objective of this project is to develop a 10% LEL methane sensor. Prototype detectors are currently undergoing a one-year pilot field study to assess performance and reliability.
 - Project close out: Q4 2020
- Stanford MEMS sensor development project (BP 18 AE-1)(NGI-2018-001)
A multi-layer silicon-based sensor approximately 1 cm x 1.5 cm in size was developed and results published (P.A. Gross et al. Analytical Chemistry, 2018). Improvements to the sensor to fulfill field deployment requirements include adjustments in hydration, method of manufacture, temperature stability, and sensitivity. The Company is currently expecting the receipt of a 1st Prototype to commence controlled laboratory evaluation
 - Project close Out – Q1 2021
- PHMSA #851 / OTD (7.20.a) Develop Remote Sensing and Leak Detection Platform with Multiple Sensors
The main objective is to demonstrate a sensing platform permanently deployed at discrete locations in the ROW. These locations are wirelessly connected to a software back-end that performs sensor data fusion to identify integrity threats in the ROW. These leading indicators can be used to prevent damage or leakage. A single prototype of this system has been deployed on a live utility site. This work would address needed improvements and deploy the system to additional utility sites.
 - Start Date: Q4 2019
 - Anticipated End Date: Q3 2021

b. PROPOSED PROJECTS

- Evaluate New and/or prototype methane sensor technologies.
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2022

2020 Leak Abatement Plan R&D Objective Summary #18
Evaluation of Stationary Methane Detectors

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

A) CURRENT PROJECTS (2018 Compliance Plan)

- Stanford MEMS sensor development project (BP 18 AE-1)
 1. Stanford Demonstration
 - Data gathered during Stanford demonstration is used to identify potential capabilities that can be leveraged for Company leak detection, speciation, and localization.
 2. Laboratory Evaluation
 - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Use results of laboratory data to provide feedback to Stanford Researchers to improve Prototype.
 - Repeat Lab Evaluation with new Prototype.
 3. Evaluate Cost of Implementation
 - Estimate cost to conduct simulated field evaluation.
 - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
 4. Simulated Field Evaluation (Controlled Environment)
 - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Use 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).
 5. Pilot Study
 - Verify capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).

2020 Leak Abatement Plan R&D Objective Summary #18
Evaluation of Stationary Methane Detectors

B) PROPOSED PROJECTS

- Evaluate available CH₄ sensors that could be used for stationary CH₄ detection use-cases at company facilities. The project will involve one or more of the following steps:
 - Manufacturer or Prototype Demonstration
 - Data gathered during manufacturer or research demonstration is used to identify potential capabilities that can be leveraged for Company leak detection, speciation, and localization.
 - Laboratory Evaluation
 - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Use results of laboratory data to guide simulated field-testing plan.
 - Evaluate Cost of Implementation
 - Estimate cost to conduct simulated field evaluation.
 - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
 - Simulated Field Evaluation (Controlled Environment)
 - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Use 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).
 - Pilot Study
 - Verify capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision).
 - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).

**2020 Leak Abatement Plan R&D Objective Summary #18
Evaluation of Stationary Methane Detectors**

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$239,150	\$479,124

SDG&E	2021	2022
	\$21,524	\$43,121

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

SoCalGas	Total Loaded Costs
	\$883,666

SDG&E	Total Loaded Costs
	\$79,530

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

PA Gross, T Jaramillo and B Pruitt, Cyclic-Voltammetry-Based Solid-State Gas Sensor for Methane and Other VOC Anal. Chem. 2018, 90, 10, 6102-6108

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<https://www.newcosmos-global.com/news/2701/>

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2020 Leak Abatement Plan RD&D Objective Summary #20a-1

Develop Distribution Mass-Balance Leak Detection and Quantification Methodology

1) BEST PRACTICE ADDRESSED

- 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 demonstration of actual emissions reductions.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Develop Distribution mass-balance leak detection and quantification methodology
- This project is a continuation of the R&D project from the prior compliance plan.
- Objective - early detection of system leaks, reduced system emissions, reduced cost of leak management, better measurement of leak duration.
- Pilot studies will be executed to evaluate implementation costs and actual efficiencies of the mass-balance methodology(s).

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The R&D objective is to develop and evaluate methodologies to detect and quantify gas leaks in a defined Distribution area using flow measurement data and mass-balance algorithms. Using available gas metering data, unbalanced Distribution segments are identified, which may provide an indication when system leaks initiate and provide a direct measurement of leakage flow rate.
- Areas targeted

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

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

2020 Leak Abatement Plan RD&D Objective Summary #20a-1

Develop Distribution Mass-Balance Leak Detection and Quantification Methodology

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
 - a) Mass Balance Model Development
 - a. The mass balance approach compares the gas supplied to the gas consumed for a defined service area. The deviation from a net-zero mass balance is an indicator of possible system leakage.
 - b. Mass-balance model development includes identifying and characterizing all gas supply and gas consumption (i.e., customer) meters in the study service area and considering the impacts of pack and draft and other variables.
 - b) Pilot Study
 - a. Identify candidate gas service areas with newer generation plastic pipe and a sufficient number of customer meters and appropriate gas supply and customer meters (e.g., meters with high accuracy with advanced analytics)
 - b. Identify and repair or quantify the flow rate of leaks in the service area
 - c. Use measurement data from installed gas supply meter(s) and customer meters to establish baseline mass balance model
 - d. Measure flow rates of any actual system leaks and test sensitivity to leak flow rates after leak repair. Simulate system leakage by performing controlled experiments with monitoring activity on the system (added/subtracted load, changes in customer count through close orders, leak repairs, etc.)

4) ANTICIPATED OR EXPECTED RESULTS

- The expected R&D benefit is early detection of system leaks resulting in more rapid leak detection and mitigation resulting in reduced emissions.
- Detecting leaks using a mass-balance algorithm approach, combined with active monitoring for leaks, could potentially reduce “unknown” leaks and theoretically reduce the need for leak surveys. This could reduce detection times to potentially years sooner (in 5-yr survey areas) and provide a means for calculating overall emissions from leaks.

5) EMISSIONS IMPACT

- Earlier detection of system leaks are expected to result in a reduction in leak emissions; however, the magnitude of this emissions reduction cannot yet be determined.

2020 Leak Abatement Plan RD&D Objective Summary #20a-1

Develop Distribution Mass-Balance Leak Detection and Quantification Methodology

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

A. CURRENT PROJECTS

- System Emissions Using Mass Balance with Advanced Meter Technology Research Project (BP 20a AF-1) – Phase 1
 - Actual Start Date: Q3 2019

B. PROPOSED PROJECTS

- System Emissions Using Mass Balance with Advanced Meter Technology Research Project (BP 20a AF-1) – Phase 1 (continued)
 - Anticipated End Date: Q4 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

a) CURRENT PROJECTS:

- System Emissions Using Mass Balance with Advanced Meter Technology Research Project (BP 20a AF-1) – Phase 1
 - Mass Balance Model Development
 - Data collection includes accuracy specifications for the gas supply and customer meters in the study service area
 - Data collection includes historical gas consumption for the study service area
 - Data analysis includes development of the mass-balance model including the estimated uncertainty in the mass balance calculation
- Pilot Study
 - Data collection includes the quantification of the flow rate of unrepaired leaks in the service area
 - Data collection includes gas flowrates/volumes measured by the gas supply and customer meters during baseline tests
 - Data collection includes gas flowrates/volumes measured by the gas supply and customer meters during controlled experiments with simulated leakage. Simulated leak rates are directly measured.
 - For the baseline tests, data analysis includes calculation of the system mass balance and estimation of the uncertainty in the mass balance calculations.
 - For the controlled experiments with simulated leakage, data analysis includes calculation of the system mass balance and the leak rate. The minimal detectable leak rate is determined and the uncertainties in the mass balance and simulated leak rate calculations are estimated.

b) PROPOSED PROJECTS:

- System Emissions Using Mass Balance with Advanced Meter Technology Research Project (BP 20a AF-1) – Continuing project

2020 Leak Abatement Plan RD&D Objective Summary #20a-1
Develop Distribution Mass-Balance Leak Detection and Quantification Methodology

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$266,167	\$267,623

SDG&E	2021	2022
	\$23,955	\$24,086

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

<u>SoCalGas</u>	Total Loaded Costs
	\$658,718

<u>SDG&E</u>	Total Loaded Costs
	\$59,285

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

- Attachment G – Advanced Meter Analytics Algorithm: Business Case Estimation
- Attachment H – Advanced Meter Analytics Algorithm: Advanced Meter Presentation

**2020 Leak Abatement Plan RD&D Summary #20a-2
Develop Improved Measurement Methods for Buried Leaks**

1) BEST PRACTICE ADDRESSED

- 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 demonstration of actual emissions reductions.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

Evaluate new or revised tools, technologies and methods to develop improved leak flow measurement methods for system leaks.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The R&D objective is to develop and evaluate technologies and methods to quickly and accurately quantify emissions from underground leaks that spread over large areas.
 - Reduce leak emissions by improving prioritization of leaks for repair
 - Improve leak measurement efficiency and reduce cost of operation
 - Pilot studies to be initiated based on results of method evaluations. Pilot studies will evaluate actual costs and efficiency improvements.
- Areas targeted

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

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

2020 Leak Abatement Plan RD&D Summary #20a-2
Develop Improved Measurement Methods for Buried Leaks

- The R&D approach to meet the objective will involve a series of planned evaluations, of the technologies and methods of interest that can include one or more of the following:
 - a) Laboratory Evaluation
 - Evaluate technologies and methods in a laboratory environment utilizing controlled natural gas releases to assess their capabilities
 - Compare to existing buried leak measurement methods
 - Determine operating range
 - Determine leak rate measurement accuracy and precision over operating range
 - Determine ancillary equipment requirements
 - b) Simulated Field Evaluation (Controlled Environment)
 - Evaluate technologies and methods in a simulated field environment utilizing controlled natural gas releases
 - Compare to existing buried leak measurement methods
 - Determine leak rate measurement accuracy and precision over operating range
 - Determine ancillary equipment requirements
 - Identify practical implementation issues and refine technologies and methodologies
 - c) Pilot Study
 - Evaluate technologies and methods in an actual field environment.
 - Compare to existing buried leak measurement methods
 - Identify practical implementation issues and refine technologies and methodologies

2020 Leak Abatement Plan RD&D Summary #20a-2
Develop Improved Measurement Methods for Buried Leaks

4) ANTICIPATED OR EXPECTED RESULTS

- The expected R&D benefit is to develop more accurate and efficient methods to quantify emissions from underground leaks that spread over large areas. More accurate measurements would produce a more accurate emission inventory and better prioritization of system leaks for repair (i.e., repair largest leaks first and reduce emissions). More efficient methods would reduce cost of operation and allow measurement of isolated leaks.

5) EMISSIONS IMPACT

- More timely and/or accurate quantification of buried leak emissions may result in reducing the time to repair leaks, and improve the operational efficiency of the process thereby reducing implementation costs.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

- Standardization of Surface Expression Equipment and Protocol (NYSEARCH M2019-002) Phase 1 and 2
 - Actual Start Date: Q2 2019
 - Anticipated End Date: Q3 2021
- SoCalGas/IES Surface Expression Measurement System

SoCalGas is currently working with IES to design a next-generation Surface Expression measurement system that can measure a larger range of leak flowrates with improved accuracy over currently employed leak rate measurement instruments. The accuracy of this next-generation HFS instrument will be +/- 10% or less, compared to the currently employed instrument accuracy of +/- 20%. Through a test matrix in a controlled laboratory environment-controlled gas rates will be introduced directly into the HFS sample line to isolate the HFS performance, and into different regions of the gas leak enclosure for further characterization. Simulated field environment testing will evaluate the practical considerations.

 - Actual Start Date: Q2 2019
 - Anticipated End Date: Q4 2021
- Laser-scan method to measure/classify underground pipeline gas leak rates

SoCalGas has devised a laser-scan method that would allow leak measurements/classifications of underground pipeline gas leaks to be conducted more rapidly and accurately than current methods. The proof-of-concept will determine the method accuracy and whether the method provides an accurate “measurement” of the

2020 Leak Abatement Plan RD&D Summary #20a-2
Develop Improved Measurement Methods for Buried Leaks

true leak rate (i.e., low measurement uncertainty) or whether the method results have a high uncertainty and should more appropriately be used to “classify” or “bucket” the leaks (e.g., as small, medium, or large).

- Anticipated Start Date: Q2 2020
- Anticipated End Date: Q4 2021
- Optical Gas Imaging (OGI) Cameras and associated leak quantification algorithms
The development or demonstration of leak quantification using OGI or estimation of leak size based on IR camera imaging and algorithms could provide rapid estimates of the size of leaks, and result in better prioritization of leak repairs (i.e., repair largest leaks first and reduce emissions). In 2019 SoCalGas investigated two currently available and viable IR camera algorithms to categorize leak rates and determined that neither technology is suitable for categorization of underground pipeline leaks at that time.
 - Anticipated Start Date: Q3 2020
 - Anticipated End Date: Q4 2021

b. PROPOSED PROJECTS

- Currently, there are no new proposed projects for this Best Practice.

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

- Standardization of Surface Expression Equipment and Protocol.
 - Data collection and analysis conducted by NYSEARCH
- SoCalGas hi-flow sampler; Laser-scan method to measure/classify underground pipeline gas leak rates; and OGI Cameras and associated leak quantification algorithms
 - a) Laboratory Evaluation
 - Data collection includes replicate measurements over a wide range of controlled leak rates to determine range of operation
 - Data analysis to determine accuracy (bias) and precision (repeatability) over the range of operation
 - Data analysis to compare performance to existing buried leak measurement methods

2020 Leak Abatement Plan RD&D Summary #20a-2
Develop Improved Measurement Methods for Buried Leaks

- Document equipment functionality and determine ancillary equipment requirements/areas for improvement
- b) Simulated Field Evaluation (Controlled Environment)
- Data collection includes replicate measurements over the range of operation determined during the Laboratory Evaluation
 - Data collection includes replicate measurements by different test teams to estimate reproducibility
 - Data analysis to determine accuracy (bias) and precision (repeatability and reproducibility) over the range of operation
 - Data analysis to compare performance to existing buried leak measurement methods
 - Document equipment functionality and determine ancillary equipment requirements/areas for improvement (e.g., leak enclosure construction and implementation)
 - Document time required to conduct measurements
 - Data analysis to estimate cost to conduct measurements
- c) Pilot Study
- Data collection includes measurements of real-world leaks in typical settings
 - Data collection includes replicate measurements by different test teams to estimate reproducibility
 - Data analysis to determine precision (reproducibility)
 - Data analysis to compare performance to existing buried leak measurement methods
 - Document equipment functionality and determine ancillary equipment requirements/areas for improvement (e.g., leak enclosure construction and implementation)
 - Document time required to conduct measurements
 - Data analysis to estimate cost to conduct measurements

**2020 Leak Abatement Plan RD&D Summary #20a-2
Develop Improved Measurement Methods for Buried Leaks**

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$330,208	\$264,621

SDG&E	2021	2022
	\$29,719	\$23,816

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

SoCalGas	Total Loaded Costs
	\$732,328

SDG&E	Total Loaded Costs
	\$65,910

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

<https://www.mybacharach.com/wp-content/uploads/2015/08/0055-9017-Rev-7.pdf>

**2020 Leak Abatement Plan R&D Objective Summary #20a-3
Develop Company Specific Emission Factors**

1) BEST PRACTICE ADDRESSED

- 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 also work together, with CPUC and ARB staff, to develop a similar methodology to improve the emissions quantification of leaks in order to demonstrate actual emissions reductions.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Develop Company Specific Emission Factors (EFs).
- Company specific EFs will result in more accurate quantification of emissions than current methods.
 - In support of Company specific EFs, develop “Above Ground Leak Quantification Method Using Soap Test”
 - Facilitates reduction of emissions through defining leak-based emission factors and reduction in time to repair and increased frequency of leak survey.
 - Pilot studies to evaluate and advance above ground methane quantification technologies.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to develop Company-Specific emission factors based upon SCG and SDGE data. These emission factors will replace current “Facility” or “Population” based Emission Factors.
Current Facility-based emission factors for Meter Set Assemblies, Distribution Regulating Stations, and potentially Transmission M&R stations will be replaced with a set of leak-based emission factors. Methane emissions from above ground leaks on facilities operating at 60 psi or less are categorized using a soap test and correlated with estimated leak rates. Transmission pipeline leaks may also be evaluated for use of a Company-specific emission factor or engineering estimate methodology.
- Areas targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
F	F, V		F	F, V	F, V		

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

2020 Leak Abatement Plan R&D Objective Summary #20a-3
Develop Company Specific Emission Factors

- The R&D approach to meet the Company-specific emission factors will involve a series of planned evaluations, that can include one or more of the following:
 - a) Gather Equipment and Operating Data
 - Transmission M&R Facilities
 - Distribution M&R Stations
 - Customer Meters
 - b) Categorize Equipment (Emissions Sources)
 - M&R Stations
 - Customer Meters
 - c) 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
 - d) Statistically Analyze Leak Data
 - e) Develop Company-specific Emission Factors

- The R&D approach to meet the soap-test based emission factors objective will involve a series of planned evaluations, that can include one or more of the following:
 - a) Laboratory Evaluation
 - Establish baseline performance testing for threaded above ground asset leaks.
 - Evaluate the test matrices to Company requirements for intended applications
 - b) Simulated Field Evaluation (Emissions Sources)
 - Evaluate each test matrix, in a simulated field environment utilizing controlled natural gas releases
 - Compare to currently approved Gas Standards
 - c) Pilot Study
 - Evaluate leak quantification method in an actual field environment, which may include controlled natural gas releases
 - d) Develop Emission Factors
 - Using leak rates with bubble characteristics develop leaker-based emission factors.

4) ANTICIPATED OR EXPECTED RESULTS

- Emission factors based upon present day conditions and local leak measurements will improve emission estimates and support better strategic decisions.
- A defined relationship between soap bubble formation and leakage rates will be determined based on the results of a field leak measurement study of above ground leaks. The results from this study will be used to develop Leak-Based emission factors.

5) EMISSIONS IMPACT

- Leaker based emission factors will enable more accurate emissions reporting. Accurate emissions inventory also facilitates proper planning and resource allocation to the emissions sources that provide for greater emissions reductions.

**2020 Leak Abatement Plan R&D Objective Summary #20a-3
Develop Company Specific Emission Factors**

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

- Develop Company-Specific Leak-Based Emission Factors for Distribution Main & Services (SCG & SDG&E) (BP 20a AI-4.5)
 - Anticipated End Date: Q4 2020

- Develop Company-Specific Leak-Based Emission Factors for Customer Meters (SCG & SDG&E) (BP 20a AI-4.6 & 4.7)
 - Anticipated End Date: Q4 2020

- Develop a detailed inventory of the different categories of M&R stations operated by SoCalGas & SDG&E (BP 20a AI-4.5)
 - Anticipated End Date: Q4 2020

- Quantification of Leaks and Define Practical Lower Emission Threshold Research Project (OTD 7.17.d) (BP 20a AH-1)
Initial testing on above ground assets at 60 psig or less demonstrated that good correlation exists between soap bubble size and leak flow rate; and that practical bubble size categories could be used to develop leaker-based emission factors.
 - Anticipated End Date: Q4 2020

b. PROPOSED PROJECTS

- Distribution Main & Services additional analysis to refine DT model and investigate additional parameters (SCG & SDG&E)
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2022

- Customer Meters additional sampling (SCG & SDG&E)
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2022

- Develop Company-Specific Leak-Based Emission Factors for Transmission M&R Station Facilities
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2022

2020 Leak Abatement Plan R&D Objective Summary #20a-3
Develop Company Specific Emission Factors

- Develop Company-Specific Leak-Based Emission Factors for Above Ground Leaks Using Soap Test Method
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

- Company-specific emission factors
 - Gather Equipment and Operating Data
Gather necessary operating data (e.g., pressure) and equipment characteristics (e.g., number of components by type and size) that can impact emissions.
 - Transmission M&R Facilities
 - Distribution M&R Stations
 - Customer Meters
 - Categorize Equipment (Emissions Sources)
Use data from task No. 1 to develop equipment categories.
 - M&R Stations
 - Customer Meters
 - Develop Equipment Sampling Plan
Leak measurement samples must be representative of the facility population to be statistically valid for the entire population of leaks in the service area. Samples must be collected randomly in order to meet this requirement.
 - Conduct Leak Measurements
Conduct leak measurements on a statistically random basis. Measure the emission rate of detected leaks in the field and document each leak source (component type and size). Measure emission rate from pneumatic devices and document each device.
 - Statistically Analyze Leak and Emissions Data
 - Develop Emission Factors
 - “Leaker” and/or “Component Population” emission factors based upon data analysis and “Fugitive” or “Vented” type of emissions
- Quantification of Small Leaks and Define Practical Lower Emission Threshold Research Project (OTD 7.17.d) (BP 20a AH-1).
 - Final results will be analyzed for capability to meet company specifications.
- Develop Company-Specific Emission factors for Above Ground Leaks Using Soap Test Method.
 - Laboratory Evaluation
 - Data gathered during laboratory evaluation is used to demonstrate capability of soap test method for intended applications. (Go/No-Go Decision).
 - Use results of laboratory data to guide simulated field-testing plan.
 - Evaluate Cost of Implementation
 - Estimate cost to conduct simulated field evaluation.
 - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).

**2020 Leak Abatement Plan R&D Objective Summary #20a-3
Develop Company Specific Emission Factors**

- Simulated Field Evaluation (Controlled Environment)
 - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications. (Go/No-Go Decision). Use results of simulated field evaluation data to guide pilot study plan.
- Pilot Study
 - Verify soap test method capability for intended applications, and that the method can meet Company specifications (Go/No-Go Decision).
 - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).
- Develop Emission Factors
 - Data gathered during pilot studies will be used to calculate emission factors.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$793,499	\$806,693

SDG&E	2021	2022
	\$71,415	\$72,602

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

<u>SoCalGas</u>	Total Loaded Costs
	\$1,600,192

<u>SDG&E</u>	Total Loaded Costs
	\$177,783

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template

11) REFERENCES

- GHG Emission Factor Development for Natural Gas Compressors, PRCI Catalog No. PR-312-16202-R02, April 18, 2018.
- Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on Subpart W Measurement Data, PRCI Catalog No. PR-312-18209-E01, October 17, 2019.

**2020 Leak Abatement Plan RD&D Objective Summary #20a-4
Model Leak Growth Rates from Polyethylene Plastic Piping Slow-crack Growth
Failures**

1) BEST PRACTICE ADDRESSED

- 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 demonstration of actual emissions reductions.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Model Leak Growth Rates from Polyethylene Plastic Piping Slow-crack Growth Failures.
 - This is a continuing Research & Development project to advance the understanding of how leaks evolve over time on various pipeline materials.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to advance industry understanding of how leak rates tend to grow over time on Polyethylene (PE) pipe once the leak has initiated. Prior to this project industry research in this area was focused on the process of crack initiation up until a leak occurred. This knowledge will assist in improving system leakage estimate and emission factors and help to optimize leak survey intervals based on projected emissions growth rates.
- Areas targeted

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

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:

a) Laboratory Testing

2020 Leak Abatement Plan RD&D Objective Summary #20a-4
Model Leak Growth Rates from Polyethylene Plastic Piping Slow-crack Growth Failures

- Multiple pipe samples are placed on test in multiple soil types in known conditions for an extended time period.
- b) Modeling
 - Using data and conditions from laboratory tests, develop a model to estimate emissions growth rate from cracks in PE pipe.
- c) Model Verification
 - Verify the model with field leak measurements between time detected and at point of repair.

4) ANTICIPATED OR EXPECTED RESULTS

- Increased understanding of the impact on methane emissions from the leak growth rate due to cracks in the Polyethylene (PE) pipeline.

5) EMISSIONS IMPACT

- The knowledge gained from this study will assist in management and estimation of methane emissions from PE pipelines. Leak rates can be projected from the time of discovery and repairs can be prioritized using this knowledge to prevent leaks from developing into large emitters.
- This knowledge can also be applied to future methane emissions studies in the development of improved Emissions Factors and methane emissions inventory reporting.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

- PE Leak Growth Rate from Slow Crack Growth Research Project (OTD 7.15.c, BP 20a AK-1)
 - Actual Start Date: Q1 2016

b. PROPOSED PROJECTS

- PE Leak Growth Rate from Slow Crack Growth (continuing) (OTD 7.15)
 - Anticipated End Date: Q4 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

**2020 Leak Abatement Plan RD&D Objective Summary #20a-4
Model Leak Growth Rates from Polyethylene Plastic Piping Slow-crack Growth Failures**

- PE Leak Growth Rate from Slow Crack Growth Research Project (OTD 7.15.c, BP 20a AK-1)
 - Laboratory Testing
 - Data gathered during laboratory testing is used as inputs to develop the model. Measurement data includes pressure, leak rate, temperature, soil type, etc. Analysis will be performed to determine relationships among the variables and the leak rates.
 - Modeling
 - During the development of the model there is no new data collection.
 - Model development will incorporate and analyze data collected from laboratory testing.
 - Model Verification
 - Demonstrate model capability for intended applications, which meet Company specifications (Go/No-Go Decision).
 - Gather field leak measurement and leak duration data
 - Correlate with leak repair data and types of plastic leaks
 - Test statistical validity of the model
 - Re-Evaluate/update the model and repeat verification if needed
 - Go/No-Go Decision

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

- Incremental Cost Estimates (Provided in 2017 Dollars and Direct Costs (No Loaders))

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$66,042	\$67,158

SDG&E	2021	2022
	\$5,944	\$6,044

2020 Leak Abatement Plan RD&D Objective Summary #20a-4
Model Leak Growth Rates from Polyethylene Plastic Piping Slow-crack Growth Failures

**9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER,
1-WAY ACCOUNT.**

SoCalGas	Total Loaded Costs
	\$163,957

SDG&E	Total Loaded Costs
	\$14,756

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

OTD Project No. 7.15.c Summary Report

2020 Leak Abatement Plan R&D Summary 20a-5
Quantification of Through-Valve Leakage on Large Compressor Valves

1) BEST PRACTICE ADDRESSED

- 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 also work together, with CPUC and ARB staff, to develop a similar methodology to improve the emissions quantification of leaks in order to demonstrate actual emissions reductions.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Quantification of Through-Valve Leakage on Large Compressor Valves.
 - Improve quantification of through-valve leaks on large natural gas compressor valves prone to leakage (i.e., blowdown valves and isolation valves) by identifying and/or developing appropriate measurement methods (i.e., instruments and measurement procedures).
 - Reduce natural gas emissions by identifying and repairing large through-valve leaks on large compressor valves.
- The evaluation of promising measurement methods for through-valve leakage emissions will be conducted on full-scale compressor valves under controlled conditions. Pilot studies will follow as deemed necessary to further evaluate emissions reductions and/or cost efficiency.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to evaluate current and new through-valve leakage emissions measurement methods and determine the best method(s) for accurate quantification.
- Areas targeted:

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
		F, V					F, V

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

- The R&D approach to meet the objective will involve a series planned evaluations, that can include one or more of the following:
 - a) Screening evaluation of measurement methods for through-valve leakage emissions.
 - b) Identify most promising measurement methods from the screening study and evaluate these methods under controlled conditions over a range of valve types and sizes, operating pressures, leak configurations, leak sizes, etc.
 - c) Identify the best practice measurement method(s) and/or need for further evaluation.

2020 Leak Abatement Plan R&D Summary 20a-5
Quantification of Through-Valve Leakage on Large Compressor Valves

4) ANTICIPATED OR EXPECTED RESULTS

- Accurate through-valve leakage measurements will lead to the ability to prioritize repair of large through-valve leaks on large compressor valves.

5) EMISSIONS IMPACT

- The current method to measure through-valve leakage emissions from compressor blowdown valves and isolation valves is an acoustic technology, which historically measures with a low bias (often measures a false zero)^A. Evaluation of the SoCalGas 2015 baseline emissions data indicates a low bias in the blowdown and isolation valve measurements, and an adjustment of the 2015 emissions using best available data is appropriate. The identification and implementation of best method(s) for accurate measurements will allow quicker mitigation of previously undetected or under-quantified large leaks.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

- Evaluate current measurement methods for through-valve leakage emissions to determine bias and precision
A 2019 PRCI Project, funded in part by SoCalGas, “Scoping Study on Unit Isolation Valve Gas Leakage at Natural Gas Compressor Stations” compiled valve population, leakage, and O&M information for more than 1,000 isolation valves. In addition, in 2019 a Companywide survey of every compression facility and corresponding compressor isolation valves was completed. Subject matter experts at each facility were interviewed and the results are summarized in an internal report. The lessons learned from these two projects are used to guide this evaluation of measurement methods for through-valve leakage emissions.
 - Anticipated End Date: Q4 2020

b. PROPOSED PROJECTS

- Identify best practice methods and procedures to identify effective emission measurement methods
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2022

2020 Leak Abatement Plan R&D Summary 20a-5
Quantification of Through-Valve Leakage on Large Compressor Valves

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

a. CURRENT PROJECTS

- Evaluate current measurement methods for through-valve leakage emissions to determine bias and precision.
 - Screening Evaluation/Manufacturer Demonstrations
 - Data will be gathered during manufacturer/user demonstrations of IR cameras, acoustic methods, ultrasonic methods, insertion flowmeters, and new methods.
 - Data analysis will include identifying measurement methods/instruments with a propensity for measuring false negatives (i.e., measurement of zero emissions when emissions are known to exist).
 - Isolation valves are installed on various pipe sizes from 1” to 24” in diameter at varying pressures up to 3,000 psi. Blowdown valves are installed on various pipe sizes from about 1” to 4” in diameter at varying pressures up to 3,000 psi. These parameters and the results of the screening evaluation will be considered to select measurement methods for further evaluation in the Controlled Study of Full-Scale Valves.
 - Go/No-Go Decision. A Go/No-Go Decision will be based on the estimated cost to conduct the Controlled Study of Full-Scale Valves as well as estimates of emission reductions and the cost impacts of implementing the measurement methods.
 - Controlled Full-Scale Valve study (Controlled through-valve leakage tests)
 - This study will assess selected measurement methods over a matrix of key parameters (e.g., operating pressure, valve type and size, leak configuration, and/or leak rate) typical of actual field conditions.
 - Data analysis will include estimation of the bias/accuracy and precision (i.e., repeatability and reproducibility) of the different measurement methods. Test results will be used to evaluate whether the measurement methods demonstrate capability for intended applications and can meet Company specifications (Go/No-Go Decision).

b. PROPOSED PROJECTS

- Identify best practice methods and procedures on preferred measurement methods
 - Data gathered during the evaluations of measurement methods for through-valve leakage emissions is used to develop best practices and procedures as applicable to specific pipe size/pressure/valve type combinations. The need to develop and/or evaluate additional methods will be determined.

**2020 Leak Abatement Plan R&D Summary 20a-5
Quantification of Through-Valve Leakage on Large Compressor Valves**

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$132,083	\$134,315

SDG&E	2021	2022
	\$11,887	\$12,088

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

<u>SoCalGas</u>	Total Loaded Costs
	\$327,915

<u>SDG&E</u>	Total Loaded Costs
	\$29,512

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

A. GHG Emission Factor Development for Natural Gas Compressors, PRCI Catalog No. PR-312-16202-R02, April 18, 2018.

B. Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, GRI-94/0257.25, EPA-600/R-96-080h, June 1996.

**2020 Leak Abatement Plan RD&D Objective Summary #20b
Geographic Emissions Tracking & Evaluation**

1) BEST PRACTICE ADDRESSED

- 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 in order to provide data for leak maps. Geographic leak maps shall be publicly available with leaks displayed by zip code or census track.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Geographic Tracking and Evaluation of Leak Data
- Increase efficiencies through error reduction and work bundling.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to integrate emissions related data from different operating organizations; develop strategies to gather and store field data electronically minimizing data error; and spatially identify facilities that fall into different categories to support data analytics.

Areas targeted

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

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v – Vented

- The R&D approach to meet the objective will involve a series of planned evaluations that can include one or more of the following:
 - a) Gather input from subject matter experts
 - b) Develop Strategies for field collection and storage
 - c) Develop methods to spatially identify facilities

**2020 Leak Abatement Plan RD&D Objective Summary #20b
Geographic Emissions Tracking & Evaluation**

- d) Incorporate into data analytics

4) ANTICIPATED OR EXPECTED RESULTS

- Reduction of electronic data error from manual data entries of field data.
- Capturing of additional data points, currently unrecorded, from field leak measurements.

5) EMISSIONS IMPACT

- The direct impact on emissions is difficult to quantify as the major benefit is the improves efficiencies from both work bundling and data entry error reduction.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

- Prior research may be leveraged to support this objective, such as GIS Platform & Data Model for Mobile Data Collection (OTD 8.17 e)
 - Anticipated End Date: Q2 2020

b. PROPOSED PROJECTS

- Gather and Store Field Data
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2021
- Spatially Identify Facilities
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q4 2021

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

a. CURRENT PROJECTS

- There are no projects in conjunction with the Best Practice.

b. PROPOSED PROJECTS

- Gather input from subject matter experts

**2020 Leak Abatement Plan RD&D Objective Summary #20b
Geographic Emissions Tracking & Evaluation**

- Data gathered from subject matter experts is used to guide strategies to gather and store field data.
- Data gathered from subject matter experts is used to categorize facilities
- Develop strategies for field data collection and storage
 - Data gathered during strategic planning will be used and analyzed to determine efficient methods of field data collection and acceptable methods of data storage that meet Company specifications. (Go/No-Go Decision)
 - Estimate cost to implement field data collection and storage
- Develop methods to spatially identify facilities and system components
 - Data gathered during the spatial identification and categorization of facilities will be evaluated for usefulness towards data analytics and work bundling.
 - Estimate cost/efficiency of facility categorization.

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$46,029	\$94,048

SDG&E	2021	2022
	\$4,143	\$8,464

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

SoCalGas	Total Loaded Costs
	\$173,017

SDG&E	Total Loaded Costs
	\$15,572

**2020 Leak Abatement Plan RD&D Objective Summary #20b
Geographic Emissions Tracking & Evaluation**

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

OTD Project No. 8.17.e Summary Report

2020 Leak Abatement Plan RD&D Summary #22

Investigate Specifications, Tolerances and Sealing Compounds for Threaded Fittings

1) BEST PRACTICE ADDRESSED

- 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.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Investigate Specifications, Tolerances and Sealing Compounds for Threaded Metal Pipe and Fittings
- Reduce emissions by reducing fugitive gas loss at threaded connections.
- Pilot studies to be initiated based on results of sealant evaluations. Pilot studies will validate actual costs and emissions reductions.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- Evaluate the sealing performance of pipe thread sealants (spray-on, brush-on, putty, or epoxy leak sealant products) that can be applied externally to threaded metal connections to lock and prevent gas leakage under varying environmental conditions, internal pressures and external loading.
- Identify the high-performance thread sealant products that can seal low pressure (7 IWC or 2 PSIG) thread leaks on existing MSAs and conduct a thorough evaluation of these products.
- Areas targeted

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

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

2020 Leak Abatement Plan RD&D Summary #22

Investigate Specifications, Tolerances and Sealing Compounds for Threaded Fittings

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
 - a) Laboratory Evaluation
 - a. Establish baseline performance for sealants that are evaluated.
 - b. Comparative evaluation to manufacturer specifications and currently approved sealants.
 - c. Evaluate the sealants to Company requirements for intended applications.
 - b) Simulated Field Evaluation (Controlled Environment)
 - a. Evaluate sealants in a simulated field environment utilizing controlled natural gas releases.
 - b. Compare to currently approved sealants, practices, and/or procedures.
 - c) Pilot Study
 - a. Obtain and evaluate multiple sealants against Company's specifications for the intended application, and test for reliability.
 - b. Evaluate sealants in an actual field environment, including controlled natural gas releases.
 - c. Compare to currently approved sealants, practices, and/or procedures.

4) ANTICIPATED OR EXPECTED RESULTS

- Company use of high-performance thread sealants may help eliminate fugitive methane emissions.
- Revising Company pipe thread specifications to ensure tighter tolerance and better-quality threads will help reduce fugitive methane emissions.
- Implement a threaded fitting replacement program for threaded components identified to have significant thread leaks.
- The project will identify the most economical thread sealants that resist leakage when exposed to varying combinations of pipe size, pressure, and temperature changes; movement; and general environmental conditions, and that provide an emissions cost-benefit when considering implementation costs of any required changes to operational practices. For example, Spray-on and brush-on type sealants will blow off by the force of the low-pressure leaks. The putty type sealants will take more time to apply but will stop low-pressure leaks. Ease of application, amount of time to apply, minimum surface preparation, and no service disruption are advantages over standard MSA dismantle and reassembly.
- Leak testing of NPT and ANPT quality pipe and fitting threads will provide performance data that will determine if company pipe fitting specifications need to be revised.

5) EMISSIONS IMPACT

- Reduce or eliminate fugitive methane emissions from aboveground threaded connections on Customer MSAs and Meter and Regulation Stations.

2020 Leak Abatement Plan RD&D Summary #22

Investigate Specifications, Tolerances and Sealing Compounds for Threaded Fittings

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

- Study Quality of Existing Pipe Fitting Inventory Research Project (NYSEARCH M2018-001)

Final Report Review and Phase 2 (Go/No-Go Decision) Q1 2020:

b. PROPOSED PROJECTS

- NYSEARCH: Phase 2 - Evaluate thread sealants to reduce emissions from pipe fittings.
Anticipated Start Date: Q1 2021
Anticipated End Date: Q3 2022
- Low pressure sealants – Identify possible spray-on, brush-on, putty, or epoxy leak sealants to seal low pressure (7IWC or 2PSIG) thread leaks on existing MSAs
Anticipated Start Date: Q1 2021
Anticipated End Date: Q3 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

a. CURRENT PROJECTS

- Study Quality of Existing Pipe Fitting Inventory Research Project (NYSEARCH M2018-001). Data gathered during the environmentally controlled testing is used to compare the effects of thread form, lubricant and torque as a function of temperature and pressure on leak rate. A baseline for NPT and ANPT is established.
- SPEC project and report

b. PROPOSED PROJECTS

- Laboratory Evaluation
 - Data gathered during laboratory evaluation will be utilized to establish performance baselines and to determine which sealants proceed to the field evaluation.
- Simulated Field Evaluation (Controlled Environment)
 - Data gathered during field evaluation will be used to compare to Company specifications and guide the Pilot Study.
- Evaluation Cost of Implementation
 - Estimate cost to conduct pilot studies
 - Estimate emissions reduction cost reduction, and cost avoidance benefits (Go/No-Go Decision)
- Pilot Study
 - Data gathered during pilot study will be utilized to determine candidates for implementation.

2020 Leak Abatement Plan RD&D Summary #22

Investigate Specifications, Tolerances and Sealing Compounds for Threaded Fittings

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$141,089	\$142,334

SDG&E	2021	2022
	\$12,698	\$12,810

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

<u>SoCalGas</u>	Total Loaded Costs
	\$348,873

<u>SDG&E</u>	Total Loaded Costs
	\$31,399

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

NYSEARCH Project M2018-001 Project Report

**2020 Leak Abatement Plan R&D Summary #23-1
Evaluation of Technologies to Mitigate Vented Emissions and Gas Blowdowns**

1) BEST PRACTICE ADDRESSED

- 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.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Evaluation of Technologies to Mitigate Vented Emissions & Gas Blowdowns
- This is an emissions reduction effort through mitigation of natural gas release which is currently part of the operation. This will also result in operational efficiencies.
- Perform pilot projects to demonstrate effectiveness and establish basis for cost estimates of technology implementation.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to:
 - Evaluate the effectiveness of various technologies (new or as discovered during records search) to mitigate vented emissions and gas blowdowns.
 - 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.
 - Perform pilot projects to demonstrate effectiveness and establish basis for cost estimates of technology implementation.
- Areas targeted

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

Primary Area of Focus: F – Fugitive; V – Vented

Secondary Area of Focus: f – Fugitive; v - Vented

2020 Leak Abatement Plan R&D Summary #23-1
Evaluation of Technologies to Mitigate Vented Emissions and Gas Blowdowns

- The R&D approach to meet the objective for technology, tool or equipment will involve a series of planned evaluations, that can include one or more of the following:
 - a) Manufacturer/In-house Demonstration
 - a. Facilitate demonstrations by manufacturers or set-up in-house prototypes of new technologies, tools or equipment.
 - b) Laboratory Evaluation
 - a. Establish baseline performance for technologies, tools or equipment that are evaluated.
 - b. Comparative evaluation to manufacturer specifications and currently approved methods.
 - c. Evaluate the technologies, tools or equipment to Company requirements for intended applications.
 - d. Simulated Field Evaluation (Controlled Environment)
 - e. Evaluate technologies, tools or equipment in a simulated field environment
 - f. Compare to currently approved technologies, tools or equipment
 - c) Pilot Study
 - a. Evaluate technologies, tools or equipment in an actual field environment, including controlled natural gas releases.
 - b. Compare to currently approved technologies, tools or equipment.
- The R&D approach to meet the objective for procedural evaluations includes:
 - a) Identify relevant operating procedures where gas is currently released as part of the operation.
 - b) Review Procedures
 - a. Identify opportunities to reduce methane emissions
 - c) Evaluate cost of implementation and prioritize opportunities
 - d) Execute demonstrations/evaluations on prioritized opportunities

4) ANTICIPATED OR EXPECTED RESULTS

- The evaluation of various technologies to mitigate gas blowdowns and vented emissions will result in recommendations to reduce blowdown events and a reduction in vented emissions.
- Opportunities that are identified in the operating procedure review may result in an evaluation and subsequent recommendation to change existing practices or to utilize new practices, tools and equipment or technology.

2020 Leak Abatement Plan R&D Summary #23-1
Evaluation of Technologies to Mitigate Vented Emissions and Gas Blowdowns

5) EMISSIONS IMPACT

- Reduce planned facility blowdown or venting of natural gas to the atmosphere and/or other operational venting by employing one or more viable options.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

GFO-19-502 Group 2: Smart Shutoff Technology for Residential and Commercial Buildings

A meter valve has been identified that is a normally closed mechanical gas valve that is installed on the service and upstream of the meter-set assembly. It provides automatic and remote shut-off in the event of fire (and optionally flood, over-pressure, seismic activity) or utility initiated disconnect.

- Anticipated Start Date – Q1 2020

b. PROPOSED PROJECTS

• Field demonstrations and evaluation of mitigation technologies

- Anticipated Start Date Q1 2021
- Anticipated End Date Q4 2022

• Evaluate impact of utilizing new technology, tools and equipment on practices and procedures

- Anticipated Start Date Q1 2021
- Anticipated End Date Q4 2022

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

- Data collection and analysis for technology, tool or equipment evaluations includes:
 1. Manufacturer/In-house Demonstration
 - Data gathered during demonstrations is used to identify potential capabilities that can be leveraged for Company reduction of planned gas release.
 2. Laboratory Evaluation
 - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the technology, tool or equipment can meet Company specifications (Go/No-Go Decision).
 - Use results of laboratory evaluation to guide simulated field-testing.

**2020 Leak Abatement Plan RD&D Summary #23-1
Evaluation of Technologies to Mitigate Vented Emissions and Gas Blowdowns**

3. Evaluate Cost of Implementation
 - Estimate cost to conduct simulated field evaluation.
 - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).
4. Simulated Field Evaluation (Controlled Environment)
 - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the technology, tool or equipment can meet Company specifications (Go/No-Go Decision).
 - Use 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).
5. Pilot Study
 - Verify capability for intended applications, and that the technology, practices and/or procedures can meet Company specifications (Go/No-Go Decision)
 - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$146,092	\$147,346

SDG&E	2021	2022
	\$13,148	\$13,261

2020 Leak Abatement Plan RD&D Summary #23-1
Evaluation of Technologies to Mitigate Vented Emissions and Gas Blowdowns

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

SoCalGas	Total Loaded Costs
	\$361,200

SDG&E	Total Loaded Costs
	\$32,508

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

<https://www.energy.ca.gov/solicitations/2019-10/gfo-19-502-storage-monitoring-smart-shutoff-and-3d-mapping-technologies-safer>

**2020 Leak Abatement Plan R&D Summary #23-2
Evaluate Component Emission Reductions Opportunities**

1) BEST PRACTICE ADDRESSED

- 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.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Evaluate Component Emission Reductions Opportunities
- Reduced emissions from component leaks and potential operational efficiency improvement through improved monitoring systems, improved performance, and changes in practices, designs, materials or novel solutions.
- Pilot studies to be executed on successful areas of improvement to validate actual costs and emissions reductions

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is two-fold:
 - Evaluate the maintenance history of Compressor and M&R Station components to identify components prone to leakage (valve stems, through-valve in closed positions, lube port, etc.). Identify opportunities to improve leak detection through monitoring systems and/or improve system performance through changes in maintenance practices, component designs, new materials, or novel solutions.
 - Evaluate emissions from system components designed to have vented emissions. Identify opportunities to reduce vented emissions through monitoring systems or improved maintenance practices, component designs, new materials, or novel solutions.
- Areas targeted

Transmission			Distribution			Storage	
Pipeline	M&R	Compressor	Pipeline	M&R	MSA	Well/Lat	Compressor
V	F,v	F,v	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

2020 Leak Abatement Plan R&D Summary #23-2
Evaluate Component Emission Reductions Opportunities

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
 - a) Evaluate maintenance histories to identify components prone to leakage
 - b) Implement lessons learned regarding valve maintenance and improved leak detection.
 - c) Evaluate emissions from system components with vented emissions
 - d) Identify opportunities to reduce vented emissions
 - e) Select opportunities based on emissions reductions and cost efficiency and evaluate on site.
 - f) Create Standard Operating Procedures, training programs, tracking plans
 - g) Develop materials, novel solutions as identified.

4) ANTICIPATED OR EXPECTED RESULTS

- Reduce methane emissions by improved valve maintenance practices and/or replacing existing equipment/materials/components with new designs that reduce emissions.

5) EMISSIONS IMPACT

- This research objective is estimated to result in emissions reduction; however, the magnitude of this emissions reduction cannot yet be determined.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

- Methane Oxidation Catalyst Research Project (NYSEARCH M2017-004) (BP 23 AP-1)
 - Actual Start Date: Q4 2017
 - Anticipated End Date: Q1 2021
- Compressor Isolation Valves Maintenance Best Practices (SoCalGas R&D)
 - Actual Start Date: Q2 2019
 - Anticipated End Date: Q1 2021

b. PROPOSED PROJECTS

- Study alternatives to reduce component leakage (Bellows valves, secondary containment, etc.)
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q3 2022
- Evaluate and revise current practices and utilize new technology, tools, equipment, and practices and procedures
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q3 2022
- Evaluation of electrohydraulic devices to replace pneumatic to replace intermittent bleed devices
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q3 2022

2020 Leak Abatement Plan R&D Summary #23-2
Evaluate Component Emission Reductions Opportunities

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

a. Current Projects

- Methane Oxidation Catalyst Research Project (NYSEARCH M2017-004) (BP 23 AP-1).
 - Proof of Concept
 - Prototype Design
 - Prototype Development
 - Lab-Scale Prototype Demonstration
- Compressor Isolation Valves Maintenance Best Practices (SoCalGas R&D) - Implement lessons learned regarding valve maintenance and improved methods to detect through-valve leakage
 - Compile existing data (e.g., make, model, size, age) regarding the population of SoCalGas compressor blowdown valves and isolation valves
 - Utilize information gathered (“lessons learned” and maintenance practices for valve systems) during interviews of SoCalGas subject matter experts to develop a draft SOP.
 - Determine Baseline Leak Conditions
 - Identify and measure through-valve leakage on a sub-population of SoCalGas compressor blowdown valves and isolation valves
 - Utilize data gathered during determination of baseline to develop better methods to detect through-valve leakage (BP 20a.5)
 - Tracking
 - After the SOP has been implemented, periodically measure through-valve leakage on the population SoCalGas compressor blowdown valves and isolation valves to determine the impact (i.e., expected emissions reduction) of the SOP implementation
- Evaluation of electrohydraulic devices to replace pneumatic intermittent bleed devices.
 - Manufacturer Demonstration
 - Data gathered during manufacturer demonstration is used to identify potential capabilities that can be leveraged for Company requirements for intermittent bleed devices.
 - Laboratory Evaluation
 - Data gathered during laboratory evaluation is used to demonstrate capability for intended applications, and that the intermittent bleed devices can meet Company specifications (Go/No-Go Decision).
 - Use results of laboratory data to guide simulated field-testing plan.
 - Evaluate Cost of Implementation
 - Estimate cost to conduct simulated field evaluation.
 - Estimate emission reduction, cost reduction, and cost avoidance benefits (Go/No-Go Decision).

2020 Leak Abatement Plan R&D Summary #23-2
Evaluate Component Emission Reductions Opportunities

- Simulated Field Evaluation (Controlled Environment)
 - Data gathered during simulated field evaluation is used to demonstrate capability for intended applications, and that the intermittent bleed devices can meet Company specifications (Go/No-Go Decision).
 - Use 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).
- Pilot Study
 - Verify capability for intended applications, and that the intermittent bleed devices can meet Company specifications (Go/No-Go Decision).
 - Re-Evaluate/update the estimated implementation costs and benefits (Go/No-Go Decision).

b. Proposed Projects

- Study alternatives to reduce component leakage (Bellows valves, secondary containment, etc.) for T&S.
 - Compile existing data (e.g., make, model, size, age) regarding the population of SoCalGas components
 - Interview SoCalGas subject matter experts to document “lessons learned” regarding maintenance practices for components, develop draft SOP
 - Determine Baseline Leak Conditions
 - Identify and measure component leaks on a sub-population of SoCalGas components
 - Implement Lessons Learned/SOP regarding valve maintenance
 - Tracking
 - After the SOP has been implemented, periodically monitor components for leakage to determine the impact (i.e., expected emissions reduction) of the SOP implementation
- Evaluate current practices to utilize new technology, tools, equipment, and practices and procedures
 - Compile existing data regarding current practices and the associated population of SoCalGas components
 - Interview SoCalGas subject matter experts to document “lessons learned” regarding the current practices, develop draft SOP
 - Determine Baseline Leak Conditions - Identify and measure emissions from a sub-population of the associated SoCalGas emission sources
 - Implement Lessons Learned/SOP
 - Tracking - After the SOP has been implemented, periodically measure from a sub-population of associated SoCalGas emission sources to determine the impact (i.e., expected emissions reduction) of the SOP implementation

**2020 Leak Abatement Plan R&D Summary #23-2
Evaluate Component Emission Reductions Opportunities**

- Compile existing data regarding new technology, tools, equipment, and practices and procedures and the associated population of SoCalGas components
 - Interview SoCalGas subject matter experts to document “lessons learned” regarding the current practices, develop draft SOP
 - Determine Baseline Leak Conditions - Identify and measure emissions from a sub-population of the associated SoCalGas emission sources
 - Implement Lessons Learned/SOP
 - Tracking - After the SOP has been implemented, periodically measure from a sub-population of associated SoCalGas emission sources to determine the impact (i.e., expected emissions reduction) of the SOP implementation

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$340,214	\$342,804

SDG&E	2021	2022
	\$30,619	\$30,852

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

SoCalGas	Total Loaded Costs
	\$840,746

SDG&E	Total Loaded Costs
	\$75,667

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

- A. GHG Emission Factor Development for Natural Gas Compressors, PRCI Catalog No. PR-312-16202-R02, April 18, 2018.
- B. Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on Subpart W Measurement Data, PRCI Catalog No. PR-312-18209-E01, October 17, 2019.

**2020 Leak Abatement Plan R&D Objective Summary #23-3
Alternative Fuel Substitution Strategy**

1) BEST PRACTICE ADDRESSED

- 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.

2) NAME AND TYPE OF RD&D OBJECTIVE OR PROGRAM PILOT

- Alternative fuels substitution strategy to reduce methane emissions by changing the Gas composition resulting in a reduced petrogenic methane concentration. Reduce emissions of petrogenic methane from gas leaks (i.e., fugitive emissions) and gas venting by blending alternative fuels.

3) R&D OBJECTIVE. WHAT DO YOU EXPECT TO LEARN?

- The research objective is to revise the current gas composition specification to achieve a reduction in petrogenic methane emissions.
- 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

- The R&D approach to meet the objective will involve a series of planned evaluations, that can include one or more of the following:
 - a) Feasibility Study
- Identify the “best” fuel substitution strategies; that is, the strategies that have the potential to reduce petrogenic methane emissions and be cost-effective.
 - b) Small Scale Demonstration and Evaluation of Reliability and Safety
- Execute testing and research to address data and technology gaps identified in the Feasibility Study and verify that any potential identified fuel substitution strategies will not impact system reliability and safety.

4) ANTICIPATED OR EXPECTED RESULTS

- The potential benefit is reduced emissions of all releases of petrogenic methane sources within the supply chain.

**2020 Leak Abatement Plan R&D Objective Summary #23-3
Alternative Fuel Substitution Strategy**

5) EMISSIONS IMPACT

- Petrogenic methane emissions reductions are expected to differ for the different fuel substitution strategies, and reduction estimates will be an output of the Feasibility Study.

6) MILESTONE (EXPECTED START DATE, FINISH DATE, OTHER KEY DATES PLANNED)

a. CURRENT PROJECTS

Prior research where investigations into gas composition has been performed may be leveraged to support this project, such as GTI Low-Carbon Renewable Natural Gas (RNG) From Wood Wastes (see Section 11 REFERENCES).

b. PROPOSED PROJECTS

- Phase 1 Feasibility Study
 - Evaluate the system gas petrogenic methane reductions associated with different fuel substitution strategies, which could include hydrogen, propane, ethane, and methane from existing biogenic methane sources
 - Evaluate other possible impacts including, but not limited to: possible impact on combustion VOC and/or NOx emissions and other criteria pollutant emissions; impact on system gas Wobbe index and existing specifications/tariffs for SoCalGas system gas; GHG emissions from fuel substitution system implementation and substitute fuel transport; and costs of fuel substitution system implementation (i.e., equipment and operating costs) and substitute fuel transport. (Go/No-Go Decision)
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q3 2021
- Phase 2: Small Scale Demonstration and Evaluation of Reliability and Safety
 - Perform small scale laboratory demonstration(s) to evaluate the impact on combustion equipment and emissions. (Go/No-Go Decision)
 - Anticipated Start Date: Q1 2021
 - Anticipated End Date: Q3 2023

7) DATA COLLECTION AND ANALYSIS PLAN-APPROPRIATE TO THE TYPE OF PROJECT

- Phase 1 Feasibility Study – gather data and make calculations to support the feasibility analysis of each alternative fuel substitution strategy identified through input of industry and subject-matter experts.
- Determine if the potential alternative fuel substitution strategy complies with existing specifications/tariffs for SoCalGas system gas or could comply with potential revised specifications/tariffs for system gas.
- Collect data to estimate GHG emissions (e.g., as petrogenic methane equivalents) from the fuel substitution system strategy implementation and substitute fuel transport.
- Collect data to estimate emissions of criteria pollutants and hazardous air pollutants, and other possible ancillary impacts, from the fuel substitution system strategy implementation and substitute fuel transport

**2020 Leak Abatement Plan R&D Objective Summary #23-3
Alternative Fuel Substitution Strategy**

- Collect data to estimate the cost of the fuel substitution system strategy implementation (i.e., capital and operating costs) and substitute fuel transport.
- Calculate estimates of net petrogenic methane emissions reductions (e.g., as petrogenic methane equivalents).
- Calculate estimates of cost-effectiveness (e.g., \$/yr for implementation / change in emissions of petrogenic methane equivalents (Δ ton/yr)).
- Alternative fuel substitution strategies that 1.) are estimated to result in net reductions of petrogenic methane equivalents emissions; 2.) have favorable (i.e., low \$/ Δ ton) estimates of cost-effectiveness; and 3.) do not have significant adverse ancillary impacts (e.g., criteria pollutant emissions) would be considered for Phase 2.
- Phase 2: Small Scale Demonstration and Evaluation of System Reliability and Safety - – gather data and conduct analyses to further evaluate whether alternative fuel substitution strategies should be implemented. Specific data collection, testing and analyses will be determined after the completion of Phase 2 and could include:
 - Data needed to refine Phase 1 feasibility analysis
 - Combustion stability testing
 - Review and evaluation of existing safety systems and practices
 - Analysis of the impact on system reliability

8) EXPECTED UTILITY TOTAL COST (IF CO-FUNDED, WHAT IS TOTAL COST?).

Incremental Cost Estimates (Provided in 2019 Dollars and Direct Costs (No Loaders))

SoCalGas	2021	2022
	\$100,063	\$100,235

SDG&E	2021	2022
	\$9,006	\$9,021

9) RATE-RECOVERABLE LOADED COSTS SUBMITTED IN THE ADVICE LETTER, 1-WAY ACCOUNT.

SoCalGas	Total Loaded Costs
	\$246,554

SDG&E	Total Loaded Costs
	\$22,190

10) OTHER RELATED ADVICE LETTER COSTS FOR THIS PROGRAM IF ANY.

No other Advice Letter costs directly related to this template.

11) REFERENCES

GTI Low-Carbon Renewable Natural Gas (RNG) From Wood Wastes
https://www.cpuc.ca.gov/uploadedfiles/CPUS_Website/Content/Utilities_and_Industries/Energy_Programs/Gas/Natural_Gas_Market/GTI.pptx