PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 1

2018 LEAK ABATEMENT COMPLIANCE PLAN EXECUTIVE SUMMARY AND TEMPLATES

2018 Leak Abatement Compliance Plan Executive Summary and Templates (D.17-06-015)

PG&E's mission and vision commits to meeting the challenge of climate change while providing safe, reliable, and affordable energy to PG&E's customers.[1] The 26 best practices documented in the Leak Abatement OIR D.17-06-015 are directly aligned with PG&E's mission and vision. In this filing, PG&E outlines its first two-year plan (2018-2019) to address the best practices. These 26 best practices emphasize minimizing methane emissions through changes to policies and procedures, recordkeeping, personnel training, leak detection, leak repair and leak prevention.

In October 2017, PG&E filed Advice Letter 3902-G submitting the preliminary cost forecast to implement the 26 best practices over the initial two-year period. Since that time, PG&E has refined its cost forecast, and concurrent with this compliance plan, is providing an updated cost forecast for its Natural Gas Leak Abatement Program. PG&E's two-year plan includes incremental work that is planned to result in approximately 552 MMscf methane emission reductions, or to reduce by 17% PG&E's 2015 reported methane emissions.

Table 1: Estimated abatement of the proposed Best Practices for the years 2018 and 2019

BP	Description	Annual Abatement (MMscf)	System Categories
7	Blowdown reduction	240	Transmission pipelines
15	3–year leak survey cycle	129	Distribution pipelines
16	Special leak survey	2.1	Distribution pipelines
21	Superemitter survey + leak repair	159	Distribution pipelines
23	High bleed pneumatics replacement	18.4	M&R Stations
24	Dig-in reduction	3.1	Distribution pipelines
	Total:	552 MMscf	

PG&E did not wait for the filing of this compliance plan to take important steps to reduce methane emissions; this plan aligns with PG&E's long-standing commitment to environmental sustainability[2] as well as PG&E's ongoing commitment to meet the Environmental Protection Agency's Methane Challenge.[3] The methane emission reductions that these best practices will achieve also support PG&E's enterprise goals around emission reductions.

[1] Our Mission: To safety and reliably deliver affordable and clean energy to our customers and communities every single day, while building the energy network of tomorrow. Our Vision: With a sustainable energy future as our North Star, we will meet the challenge of climate change while providing afforadable energy for all customers.
[2] In 2017, for the eighth year in a row, PG&E was selected for the Dow Jones Sustainability North America Index. PG&E was one of only eight U.S. gas and electric utilities to be named to the index in 2017. The Dow Jones Sustainability North American Index lists North American companies that lead their industries in corporate economic, environmental and social performance. The index serves as a benchmark for investors who integrate sustainability consciousness into their portfolios, while providing a platform for companies that want to adopt sustainability best practices.
[3] The Environmental Protection Agency's Methane Challenge was launched in 2016 with PG&E as one of its 41 founding partners. The challenge is designed to give oil and gas companies, including utilities, a voluntary platform

In addition, many of PG&E's efforts to improve safety and reduce risk on its gas system have the added benefit of reducing methane emissions, and are incorporated into this compliance plan. PG&E has made significant strides in several key safety metrics that also have a direct impact on methane emissions:

- Reduced the Grade 2 leak backlog from over 12,000 open leaks in 2010 to 65 in 2017
- Improved emergency response times from 33.3 minutes in 2010 to 20.4 minutes in 2017
- Reduced 3rd party dig-in rate from 3.5 in 2010 to 1.89 in 2017

All of these improvements result in reducing the number of open leaks on PG&E's gas system or reducing the amount of time those leaks emit methane into the atmosphere.

PG&E anticipates current emission reduction efforts will achieve a 17% decrease in emissions over the next two years. However, these efforts alone will not be enough to achieve 40% reduction in methane emissions from 2013 levels. To achieve this goal, PG&E will need to continue research and development efforts into new technologies to improve leak detection, quantification and repair capabilities, as well as improvements in processes to limit the release of methane into the atmosphere.

PG&E will prioritize the largest sources of emissions identified in its annual reports: Transmission and Distribtion Measurement & Regulation (M&R) stations, Distribution pipelines and Customer Meter Sets. However, one of the challenges limiting methane abatement from these sources is the use of standard Emission Factors that do not reflect the impact of new technologies and operation improvements. PG&E looks forward to working with CPUC, CARB and the industry to develop new techniques allowing a more specific characterization of emissions.

At the time of this filing: 13 best practices are in place and complete; 8 are planned to be in progress during 2018 and 2019; and 6 will be piloted during the timeline of this plan.

The focus of this plan is cost-effective methane emissions reduction and PG&E believes its proposed programs balance significant reductions in methane emissions with appropriate costs. Highlights of this compliance plan include the following:

- An increased pace of leak survey using state-of-the-art leak detection technology,[4]
- more leak repairs,[5] and
- further emissions reductions from gas transmission projects that typically vent to atmosphere.[6]

PG&E also plans to conduct research and development studies to develop new technologies to enable methane emission reduction, refine emission factors for more accurate data for emissions reporting, and to evaluate if PG&E's emission reduction activities are both meaningful and cost-effective.[7]

to make specific and transparent commitments to reduce methane emissions, including through the investment in technology.

[4] See BP15, which includes accelerating the pace of gas distribution leak survey from every four to three years.

[5] See BP21.

[6] See BP2 – BP7.

PART 1: OVERVIEW

a) Best Practice: 1 **b) Status:** Complete

Compliance Plan

Written Compliance Plan identifying the policies, programs, procedures, instructions, documents, etc. used to comply with the Final Decision in this Proceeding (R.15-01-008). Exact wording TBD by the company and approved by the CPUC, in consultation with CARB. Compliance Plans shall be signed by company officers certifying their company's compliance. Compliance Plans shall include copies of all policies and procedures related to their Compliance Plans. Compliance Plans shall be filed biennially (i.e. every other year) to evaluate best practices based on progress and effectiveness of Companies' natural gas leakage abatement and minimization of methane emissions.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

None. This is the first occurrence.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

The sections that follow address PG&E's plans to comply with the 26 Best Practices adopted in the Final Decision. PG&E will enter the compliance plan into its internal tracking system to enable filing on a biennial basis, and will include the plan as a section of its Gas Safety Plan. In addition, a management review of the overall plan is performed prior to submission. The details of implementing each best practice can be found in each best practice template below.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

This best practice does not have an overlap with other regulations; however, other best practices as mentioned in their respective templates do include work execution associated with other regulations. For details on those specific regulations and the work associated with each best practice, see question d) in each of the follow best practices.

e) What technology is required to implement the best practice and why?

As noted above in question c), PG&E uses its existing internal tracking program to monitor compliance with the requirement to file a biennial compliance plan.

f) Will work require additional personnel and/or contract support? If so, please provide details.

For this initial filing, PG&E reallocated resources to support the 2018-2019 compliance plan filing. PG&E anticipates that the reallocated resources utilized in this filing will not be required in future filings and will incorporate the tasks of the additional resources into it existing processes.

g) What changes to existing operations are required? How will those changes be implemented?

No changes to existing operations are required.

[7] See row "j" in each BP.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
PG&E will develop a Process manual for future compliance plan updates.

i) Timeline for implementation (Milestones):
The timeline for developing the compliance plan is in accordance with the directive outlined within R.15-01-008.[8]

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
No costs are associated with this BP. As mentioned in question f) above, PG&E has reallocated resources for this filing and will incorporate the work associated with future filings into normal business operations.

k) Identify any cost benefits from this BP, when cost estimates are known:
See question j) above.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
See question j) above.

m) Anticipated Emissions Reductions from this BP:
No reductions in emissions are anticipated for this BP. This best practice is specific to creating a process and not related to work activities that reduce emissions. Emission reductions associated with each of the best practices below can be found in question m) of each best practice respectively.

2015 Baseline Emissions affected, where known:
Not applicable, see question m) above.

n) Calculation Methodology:
Not applicable, see question m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
Guidance documents that are a part of the compliance plan, identify, when relevant, safety items associated with following the guidance. Other documents used in this compliance plan like policies, standards or manuals, may also identify and address safety issues.

SUPPLEMENTAL INFORMATION

a) Technology:

[8] D.17-06-015, page 173, BP1 - Compliance Plans shall be filed biennially (i.e. every other year) to evaluate best practices based on progress and effectiveness of Companies' natural gas leakage abatement and minimization of methane emissions.

None.
b) Changes to Operations: None.
c) Research or Studies: None.
d) Other: None.

PART 1: OVERVIEW

a) Best Practice: 2 **b) Status:** In progress

Methane GHG Policy

Written company policy stating that methane is a potent Greenhouse Gas (GHG) whose emissions to the atmosphere must be minimized. Include reference to SB 1371 and SB 1383. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of Compliance Plan filing.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

Taking action to address climate change is integral to PG&E's mission to provide safe, reliable, affordable and clean energy to its customers. Since 2006, PG&E has maintained a Climate Change Policy that recognizes the challenges posed by climate change, as well as PG&E's commitment to reduce its greenhouse gas emissions and help its customers do the same. PG&E's Climate Change Policy was adopted in 2006 and last updated in 2012. Updating the policy to include a specific reference to minimizing methane emissions is consistent with prior updates that have accounted for the evolving nature of PG&E's commitment to address climate change.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E will update its existing Climate Change Policy using the Company's standard policy revision process to include a specific reference to minimizing methane emissions, which are a potent greenhouse gas. See supplemental section below for existing Climate Change Policy.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

No overlap with other regulations exists.

e) What technology is required to implement the best practice and why?

No technology enhancements are required.

f) Will work require additional personnel and/or contract support? If so, please provide details.

No additional personnel is required to update the existing policy.

g) What changes to existing operations are required? How will those changes be implemented?

No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.

PG&E will update its existing Climate Change Policy using the Company's standard policy revision process. The policy will be updated to include a specific reference to minimizing methane emissions, which are a potent greenhouse gas, and to Senate Bill (SB) 1371 and SB 1383.

i) Timeline for implementation (Milestones):

An update to the corporate climate change policy will occur by the end of 2018 per PG&E's policy update procedure. A final release of the updated plan will be implemented by use of PG&E's external and internal communication channels.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
Policy only; Cost-effectiveness not applicable.

k) Identify any cost benefits from this BP, when cost estimates are known:
Cost benefits have not been identified at this time.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
No overlap; this BP refers to policy only.

m) Anticipated Emissions Reductions from this BP:
As a policy only BP, this will not result in methane emission reductions. BPs 3-7 will result in methane reductions.

2015 Baseline Emissions affected, where known:
Please see the response under part m) above.

n) Calculation Methodology:
Please see the response under part m) above.

o) Additional Comments:
Standards, procedures and guidance documents described in this BP will likely encompass responses for several BPs.

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that result, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
None.

d) Other: See attached for existing Climate Change Policy (BP02_ATCH01).

PG&E Corporation

Corporation Policy: ENV-03
Effective: 06/01/2012

Climate Change Policy

Policy Statement:

We recognize that climate change threatens to significantly alter the physical environment for this and future generations. We also recognize that the electric and natural gas industry is a significant contributor to greenhouse gas emissions, and, as such, has a responsibility to find solutions and take action.

Consistent with our company values, we will be accountable for all of our own actions as they relate to protecting the environment and we are committed to working together, as a team, to pursue excellence and promote innovation. These values form the basis of who we are and drive our actions every day. With regard to climate change, this means that we have an obligation to act responsibly and to lead by example. We will do this by:

- maintaining a greenhouse gas emissions profile for our utility's delivery mix that is among the lowest in the nation,
- developing and investing in robust customer energy efficiency programs,
- supporting innovative fleet management practices,
- identifying and pursuing alternative ways to generate, procure and deliver vital energy resources, including renewable energy and clean, distributed technologies,
- being transparent about our emissions sources and verifying our emissions data,
- helping our customers minimize their greenhouse gas emissions footprint, and
- sharing "best practice" policies and programs with others in our industry and encouraging them to take action.

While we have worked cooperatively with local, state, and federal partners to achieve significant greenhouse gas reductions and to avoid emissions, we recognize that voluntary initiatives alone will not be enough. PG&E believes effectively combating global climate change will take sustained and coordinated international action, cooperation, and investment over the long term. In the meantime, however, PG&E believes that it is important for the U.S. to begin to address this issue formally and take a leadership role. We, therefore, support and prefer national legislative action that takes a mandatory, market-based approach to achieve emission reductions efficiently, economically, and in a way that encourages investment in the next generation of energy technologies, protects our customers and minimizes impacts to the U.S. economy.

Target Audience:

This policy applies to the employees of PG&E Corporation and its affiliates and subsidiaries, including Pacific Gas and Electric Company.

PG&E Corporation

Corporation Policy: ENV-03
Effective: 06/01/2012

Accountability:

The Vice President, Environmental, Pacific Gas and Electric Company implements and monitors compliance with this policy.

Approval:

Key Contacts:	Melissa Lavinson, Senior Director, Federal Affairs
Reviewed by:	Ezra Garrett, VP, Community Relations and Chief Sustainability Officer, Pacific Gas and Electric Company Diane Ross-Leech, Director, Environmental Policy, Pacific Gas and Electric Company
Sponsoring Officer:	Janet Loduca, VP, Environmental, Pacific Gas and Electric Company
Final Review by Compliance and Ethics:	Dean Mortensen, Principal, Compliance and Ethics, 05/29/2012
Approved by:	Greg Pruett, SVP, Corporate Affairs, PG&E Corporation and Pacific Gas and Electric Company
Effective:	06/01/2012
Scheduled Review:	01/01/2015

Revision Notes:

Where	What Changed
Accountability and Approval sections:	Administrative changes only due to retirement of approving officer, the Vice President, Corporate Environmental and Federal Affairs and Chief Sustainability Officer, and subsequent organizational changes. . Accountable and Sponsoring Officer is now the Vice President, Environmental, Pacific Gas and Electric Company. .

PART 1: OVERVIEW

a) Best Practice: 3 **b) Status:** In progress

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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

Methane reduction strategies for non-emergency venting, including reducing pipeline pressures by use of drafting and cross compression, have been successfully used by PG&E primarily on its backbone system where the largest benefit is obtained.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

In order for PG&E to meet its sustainability goals and comply with SB 1371 and SB 1383, PG&E will develop a new standard to reduce methane emissions as much as possible during non-emergency gas transmission blowdowns while maintaining the safety and reliability of PG&E's gas system. This new standard will provide direction to:

- Schedule all planned gas transmission system construction projects with sufficient lead time to incorporate emission reduction strategies, including: project bundling, drafting, cross-compressing and flaring;
- Reduce pressures of transmission isolation areas to lowest operationally feasible levels to minimize the venting of methane;
- Document significant factors considered in methane abatement decisions for all planned transmission projects;
  Measure all transmission blowdown and reduction amounts for all scheduled projects;
- Accelerate leak detection and repairs where feasible and employ methane reduction strategies in making associated transmission system repairs.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

40 CFR 98.232(m), 40 CFR 98.233(i) currently requires reporting of transmission blowdown amounts from vessels equal to or greater than 50CF. This BP requires greater focus on emission reduction strategy which is beyond 40 CFR federal code requirements.

e) What technology is required to implement the best practice and why?

The technology required to implement this best practice is a system to capture estimated emission reductions, actual emissions reductions, and factors in determining reduction amounts.

f) Will work require additional personnel and/or contract support? If so, please provide details.

Work identified to meet the proposed standard will require additional resources to support development, start up, implementation and quality control of processes and tools to support this work.

An initial assessment suggests the need for a consolidated resource requirement of 4.5 Full Time Employees (FTEs) for BP's 3-7.

g) What changes to existing operations are required? How will those changes be implemented?
The proposed new standard would incorporate identification of potential methane reduction into the existing project planning process, requiring an evaluation of bundling and other reduction strategies on a per project basis and documentation of findings. Project schedules for projects that show potential of greenhouse gas (GHG) reductions will need to be adjusted or extended to account for time required to implement reduction strategies. Enhanced processes to calculate volumes, capture pressures, calculate reductions, quality control data gathered, and report out reduction achievements will need to be developed and deployed. Data captured as part of the new process will be documented in SAP. Process and IT changes will be rolled out using existing internal process change and IT rollout processes which includes change management.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
A new standard must be developed to outline methane reduction strategy review. This new standard should be linked to existing standard TD-5600S (Tracking Green House Gas Emissions). See the supplemental section below for additional details. BP 6 references PG&E existing Gas Clearance Standard (TD-4441S) and Gas Transmission Clearance Procedures (TD-4441P-10 through TD-4441P-19), which shall be modified to reference the new standard and procedures outlined in this BP.

i) Timeline for implementation (Milestones):
Q1-Q3 2018: Engage Standards team to begin working on a new standard for methane reduction.
Q1-Q3 2018: Develop Procedures to determine reduction feasibility and method of documenting reduction planning efforts which include the lowering of line pressures in segments to be isolated to lowest operationally feasible level.
Q3 2018: Circulate Standard and Procedures to management for comment and review.
Q4 2018: Implement technology upgrade to begin automated tracking and reporting of methane reduction
Q1 2019: Execute reduction procedures for all Gas Transmission work requiring a blowdown
Q1 2019: Finalize formal standard

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
A cost effectiveness measure for this BP has not been developed. The following are factors or considerations that may be used to determine cost-effectiveness of this BP:

- Environmental impacts of PG&E's methane reduction decisions;
- Percentage of total project cost;
- Value of gas released;
- Incremental cost of additional reduction;
- Customer impacts;
- Power generator impacts;
- Weather impacts; and
- Economic Feasibility (will consider the amount of gas to be released versus costs to retrofit site, employ additional equipment, make changes to system, etc.) – to be developed.

k) Identify any cost benefits from this BP, when cost estimates are known:

Cost benefits are unknown at this time.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
Costs from methane reduction efforts will not overlap with costs from PG&E's current gas release tracking process. Costs associated with this BP will overlap with costs associated with the implementation of BP5.

m) Anticipated Emissions Reductions from this BP:
During the year 2017, PG&E reduced its transmission system methane emissions by 255 MMSCF by use of drafting. Annual methane emission reductions are dependent upon a number of elements including but not limited to the type and location of planned work. There is an overall goal as a part of the Methane Challenge voluntary program, which is discussed more in BP 7.

2015 Baseline Emissions affected, where known:
See PG&E's response to question m) above.

n) Calculation Methodology:
See PG&E's response to question m) above.

o) Additional Comments:
Standards, procedures and guidance documents described in this BP will likely encompass responses for several BPs (BP2, BP3, BP4, BP5, BP6, BP7 have interconnected responses).

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
See the attached TD-5600S (Tracking Green House Emissions) (BP03_ATCH01) for the future location of the standard language addressing question h) above.

c) Research or Studies:
None.

d) Other:
None.

Pacific Gas and Electric Company®

Utility Standard: TD-5600S
Publication Date: 11/15/2017, Effective Date: 11/29/2017 Rev: 0

Tracking Greenhouse Gas Emissions

SUMMARY

This utility standard describes the process and requirements for tracking and reporting greenhouse gas (GHG) blowdown, performed by the Pacific Gas and Electric Company (PG&E or Company), as mandated by Code of Federal Regulations (CFR), Title 40, “Protection of the Environment.”

TARGET AUDIENCE

Personnel working in the following areas: contract management, gas control, gas system planning (GSP), gas pipeline operations and maintenance (GPOM), general contracting construction, inline inspection (ILI), regulatory compliance, reservoir engineering, strength testing, station engineering, transmission project clearance operations (TPCO), and station assessment personnel.

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REQUIREMENTS

1 Roles and Responsibilities

1.1 Gas control personnel are responsible for:

1. Tracking pressures for blowdown for reporting purposes
2. Ensuring clearances have key communication steps
3. Managing and storing data

1.2 Field service personnel are responsible for:

1. Creating and performing work clearances
2. Performing maintenance operations
3. Completing and submitting documentation of the analyzed system

Tracking Greenhouse Gas Emissions

1.3 Project managers are responsible for:

1. Ensuring project engineering personnel is involved in the clearance process.

1.4 Gas plant engineering and design personnel are responsible for:

1. Estimating and calculating volume of analyzed system
2. Submitting and reporting volumes

1.5 Facility engineering personnel are responsible for:

1. Estimating and calculating volume of analyzed system
2. Submitting and reporting volumes

1.6 Pipeline engineering personnel are responsible for:

1. Estimating and calculating volume of analyzed system.
2. Submitting and reporting volumes

1.7 Stations assessment personnel are responsible for:

1. Identifying and reviewing components to include in calculations
2. Calculating all components of the analyzed system
3. Submitting reports to requestor

1.8 Inline inspection personnel are responsible for:

1. Estimating and calculating volume of analyzed system
2. Submitting and reporting volumes

1.9 Air quality personnel are responsible for:

1. Reporting data to CPUC
2. Estimating and calculating volume of analyzed system after emergencies

1.10 Asset knowledge management personnel are responsible for:

1. Creating and updating list of stations that operate at or above 20% specified minimum yield strength (SMYS)

Tracking Greenhouse Gas Emissions

2 Calculating Volumes of Chamber

2.1 When release of gas to the atmosphere occurs on the transmission system, the volume of the gas system must be calculated. Calculations are based on pressure of the system before the blowdown. The temperature is assumed to be 60ºF when not specified. When tracking gas blowdown for emergencies refer to Attachment 1, "Greenhouse Gas Emissions Tracking for Emergencies."

2.2 Unit and station blowdowns are tracked separately, and chamber volume is calculated separately and reviewed annually by station services personnel. When tracking gas blowdown for maintenance work refer to Attachment 2, "Greenhouse Gas Emissions Tracking for Maintenance."

2.3 All pressurized chamber volumes between the isolation points must be calculated and documented regardless of their size. Reporting to regulatory agencies is required only when the chamber volume is greater than or equal to 50 standard cubic feet. When tracking gas blowdown for project work refer to Attachment 3, "Greenhouse Gas Emissions Tracking for Projects."

2.4 The following are excluded from this standard: emissions from PG&E distribution system, emissions from flaring, overpressure relief, operating pressure control venting, blowdown of non-GHG gases, and desiccant dehydrator blowdown venting before reloading.

2.5 In some instances, there are distribution stations that include transmission assets. This occurs when the station has piping operating at or above 20% SMYS. These sections of pipe are also required to be calculated when being blown down. The list of stations that fall under this criteria is updated yearly by the second week of December.

2.6 For planned projects, corrective and preventative maintenance, and emergency work for stations, refer to Utility Procedure TD-5600P-01, "Tracking Chamber Volumes for Gas Transmission Stations."

2.7 For planned projects, corrective and preventative maintenance and emergency work for pipeline, refer to the Utility Procedure TD-5600P-02, "Tracking Chamber Volume for Gas Transmission Pipeline."

END of Requirements

DEFINITIONS

Chamber volume: Physical volume inside the isolated section that is pressurized, then vented or blown down.

IMPLEMENTATION RESPONSIBILITIES

The Senior Director of Asset Management and System Operations will issue a communication to all stakeholders about the new greenhouse gas standard and procedures. Directors and managers within the line of business will review the communication with supervisors. Supervisors will tailboard new requirements and system to employees.

Tracking Greenhouse Gas Emissions

GOVERNING DOCUMENT

NA

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Code of Federal Regulations (CFR) Title 40–Protection of Environment, Chapter I–Environmental Protection Agency, Subchapter C–Air Programs, Part 98–Mandatory Greenhouse Gas Reporting, Section (§) 98.232, “GHGs to report.”

Code of Federal Regulations (CFR) Title 40–Protection of Environment, Chapter I–Environmental Protection Agency, Part 98–Mandatory Greenhouse Gas Reporting, §98.233, “Calculating GHG emissions.”

REFERENCE DOCUMENTS

Developmental References:

NA

Supplemental References:

Utility Procedure TD-5600P-01, “Tracking Chamber Volumes for Gas Transmission Stations”

Utility Procedure TD-5600P-02, “Tracking Chamber Volume for Gas Transmission Pipeline”

APPENDICES

NA

ATTACHMENTS

Attachment 1, “Greenhouse Gas Emissions Tracking for Emergencies”

Attachment 2, “Greenhouse Gas Emissions Tracking for Maintenance”

Attachment 3, “Greenhouse Gas Emissions Tracking for Projects”

DOCUMENT RECISION

NA

DOCUMENT APPROVER

Dan Menegus, Director, Gas System Operations

DOCUMENT OWNER

Jonathan Lew, Associate Gas Engineer, Gas Guidance Documents

Tracking Greenhouse Gas Emissions

DOCUMENT CONTACT

Kenneth Rogers, Principal, Gas Outage Scheduling

REVISION NOTES

Where?	What Changed?
NA	This is a new standard.

PART 1: OVERVIEW

a) Best Practice: 4 **b) Status:** In progress

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 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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

Methane reduction strategies, including reducing pipeline pressure by use of drafting and cross compression, have been successfully used by PG&E primarily on its backbone system where the largest benefit is obtained.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E will develop a guidance document instructing those involved in the planning and execution of planned gas transmission work to build time into project schedules to:

- Identify opportunities for transmission system methane reductions to the lowest operationally feasible level;
- Schedule all planned gas transmission system construction projects with sufficient lead time to incorporate emission reduction strategies, including: project bundling, drafting, cross-compressing and flaring;
- Accurately measure and record both avoided and actual methane emissions as an integral activity of the project;
- Consistent with current company practices apply no higher safety standard/risk assessment to methane abatement activities; and
- Prepare an outlook of field activities relating to methane abatement, with reporting frequency to be determined between PG&E and the governing agencies.

Due to the dynamic nature of project schedules, PG&E cannot provide specific schedule information with a high degree of accuracy for large scheduling windows. PG&E is proposing a phased rollout of a new guidance document with initial implementation on all backbone projects in late 2018 and then transitioning to local transmission system in early 2019. PG&E also plans to incorporate further discussion between PG&E and governing agencies to determine an agreed upon frequency of field activities outlook reporting.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

None.

e) What technology is required to implement the best practice and why?

Technology is needed to streamline the collection, calculation, documentation and reporting of methane reductions. Assessment to determine specific needs of technology has not been completed.

f) Will work require additional personnel and/or contract support? If so, please provide details.
Additional resources to develop, implement, and sustain methane reductions will be required. Initial assessment suggests the need for a consolidated resource requirement of 4.5 Full-time employees (FTEs) for BP's 3-7.

g) What changes to existing operations are required? How will those changes be implemented?
A new standard to outline methane reduction strategy review and a new guidance document to build additional time into project schedules for implementation will be required. Both changes should be incorporated into existing Gas Transmission (GT) project delivery system process. See supplemental section below for more details.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
The new items that are needed include:

- A new standard will be written noting that methane reduction must be considered for all non-emergency Gas Transmission blowdowns and implemented where feasible;
- New procedures will be written to explain how to determine feasibility and how to document reduction planning for each specific project; and
- A job aid/guidance document will be composed and circulated to stakeholders explaining the change in the process and referencing the new standard and procedures.

i) Timeline for implementation (Milestones):
Q1-Q3 2018: Develop procedures to determine reduction feasibility and method of documenting reduction planning efforts.
Q1 2018: Engage Standards team to begin working on a new standard for methane reduction
Q3 2018: Circulate procedures to management for comment and review.
Q4 2018: Implement IT upgrade to begin automated tracking and reporting of methane reduction
Q1 2019: Execute reduction procedures for all Gas Transmission work requiring a blowdown.
Q1 2019: Finalize formal standard and guidance documents.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
The factors or considerations used to determine cost-effectiveness of this BP include:

- Environmental impacts of PG&E's methane reduction decisions;
- Operational safety;
- Operational reliability;
- Customer impacts;
- Forecasted weather;
- Power generator impacts; and
- Economic Feasibility (will consider the amount of gas to be released versus costs to retrofit site, employ additional equipment, make changes to system, etc.) – to be developed.

k) Identify any cost benefits from this BP, when cost estimates are known:
No cost benefits have been identified at this time.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
Costs from methane reduction efforts will not overlap with costs from other PG&E's gas release tracking.

m) Anticipated Emissions Reductions from this BP:
Emission reductions from this BP are unknown at this time. There is an overall goal as a part of the Methane Challenge voluntary program, which is discussed more in BP 7.

2015 Baseline Emissions affected, where known:
See PG&E's response to question m) above.

n) Calculation Methodology:
See PG&E's response to question m) above.

o) Additional Comments:
Standards, procedures and guidance documents described in this BP will likely encompass responses for several BPs (BP2, BP3, BP4, BP5, BP6, BP7 have interconnected responses).

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
See the attached for reference to the Project Delivery System (PDS) process that will be updated (BP04_ATCH01).

c) Research or Studies:
None.

d) Other:
None.

PROJECT FRAMEWORK – JOB AID

Project Stage	P6 Date Actualized	Key Deliverables	Key Applicable Unifier Workflow [Workflow Initiator]
Portfolio Planning	n/a	1) Project Validation Document	n/a
Initiation/ Planning	Advanced Authorization	1) Project Execution (PE) Plan 2) Project Risk Assessment/Register*	Advance Authorization**# [PCA/PM]
Design	Design Basis Memo	1) Project Validation Document 2) Design Basis Memorandum (DBM) 3) Site/Route Analysis, if applicable 4) Project Execution (PE) Plan 5) Risk Register 6) Job Estimate - Class 5 or 4 7) P6 Schedule 8) Project Phase Gate Approval Request Form	DBM & Preliminary Site/Route Analysis [PCA/PM]: **PROJECT PHASE GATE 1**
	30% Project Review Acceptance Date	1) Design Basis Memorandum (DBM) 2) PE Plan (Updated) 3) Job Estimate - Class 4^ 4) 30% Project Review Checklist 5) Schedule (SD-12 Report Milestones)	30% Project Review [PCA/PM]
	60% Project Review Acceptance Date	1) Project Execution (PE) Plan 2) Site/Route Analysis, if applicable 3) Risk Register 4) Job Estimate – Class 3 5) P6 Schedule 6) Process Hazard Analysis 7) 60% Design Drawing 8) Workspace Map 9) Project Phase Gate Approval Request Form	60% Project Review [PCA/PM] **PROJECT PHASE GATE 2**

(continued on next page)

Project Stage	P6 Date Actualized	Key Deliverables	Key Applicable Unifier Workflow [Workflow Initiator]
Design (Continued)	90% Project Review Acceptance Date	1) PE Plan (Updated) 2) Job Estimate - Class 2^ 3) 90% Project Review Checklist 4) Schedule (SD-12 Report Milestones)	90% Project Review [PCA/PM]
	Job Estimate Approved	1) Project Execution (PE) Plan 2) Risk Register/ Quantitative Risk Analysis ($5M+) 3) Job Estimate – Class 2 4) P6 Schedule 5) PHA 6) IFC Design Drawing 7) Project Phase Gate Approval Request Form	Project Authorization** [PCA/PM] **PROJECT PHASE GATE 3**
	NTP	1) IFC Job Package Checklist	IFC Job Package (includes NTP) [PCA/PM]
Construction	Substantial Completion Date	1) None (Checklists and form embedded in Unifier workflow)	- Substantial Completion (if Contractor) [CM] - Punchlist (if Contractor) [CM]
	Operational Change Notice (OCN)	1) OCN 2) Redlined Op Maps & Diagrams 3) Asset Registry Add/Edit Sheet	Operational Change Notice (OCN) [PCA/PM]
	RTO Acceptance Date	1) Release to Operations (RTO) Close Checklist	Release to Operations** [PCA/PM]
Order Closeout	n/a	1) None (Checklists and form embedded in Unifier workflow)	Construction Contract Close (if Contractor) [automatically initiated after Punchlist complete]
	SAP Financial Close	1) Project Order Closeout Checklist	Project Order Closeout [PCA/PM]

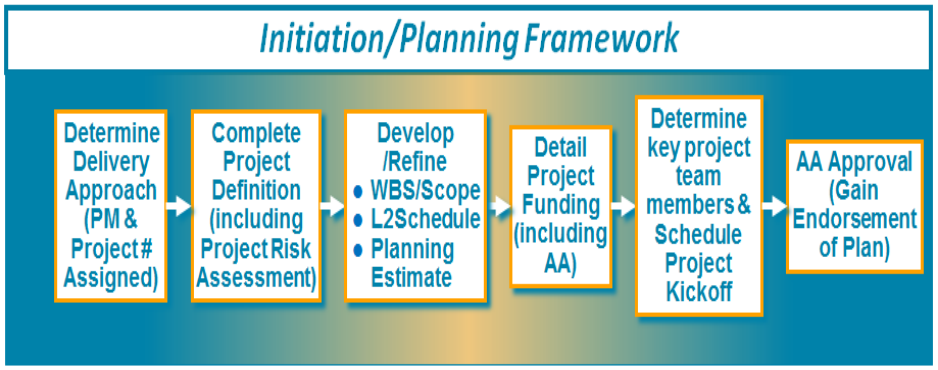
* Project Risk Register required for projects $1M+. If less than $1M, Project Risk Assessment can be used.

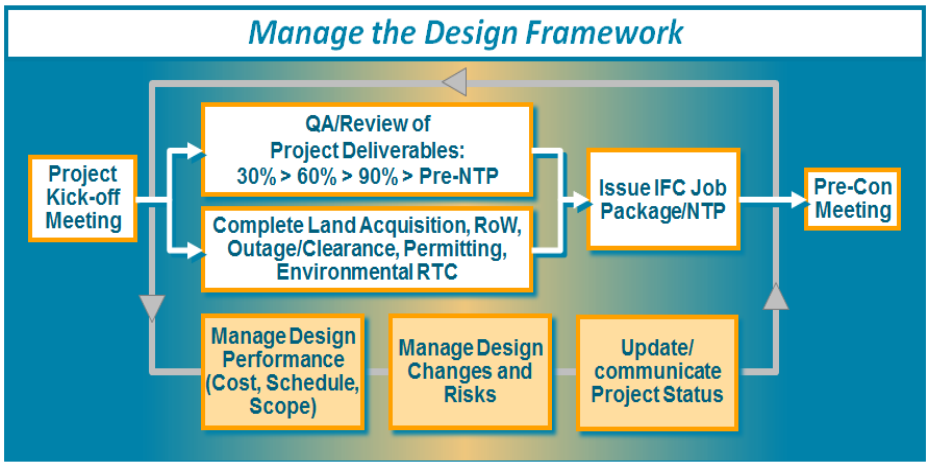
** AAs >=$5M and Project Authorizations >=$20M are approved in EDRS due to certain limited Unifier usage.

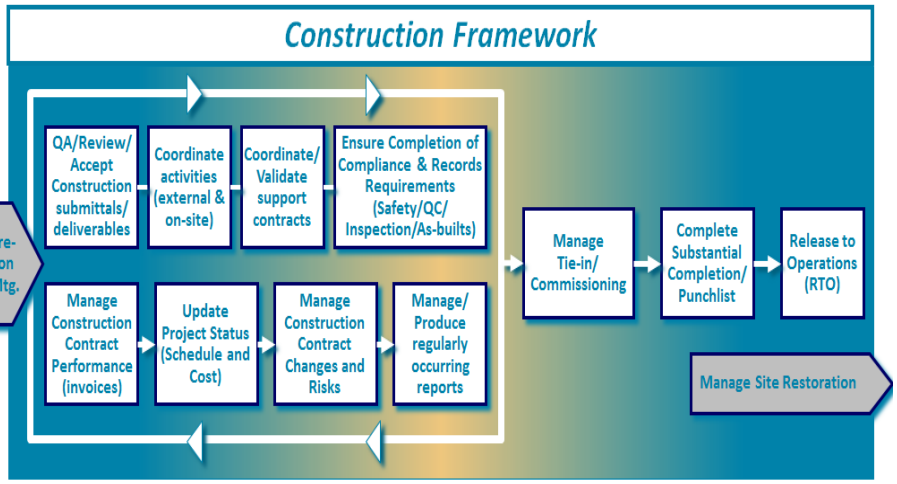
Up to $50k may be expended for preliminary PM, Engineering or JE activities. AA approval required prior to spending over $50k.

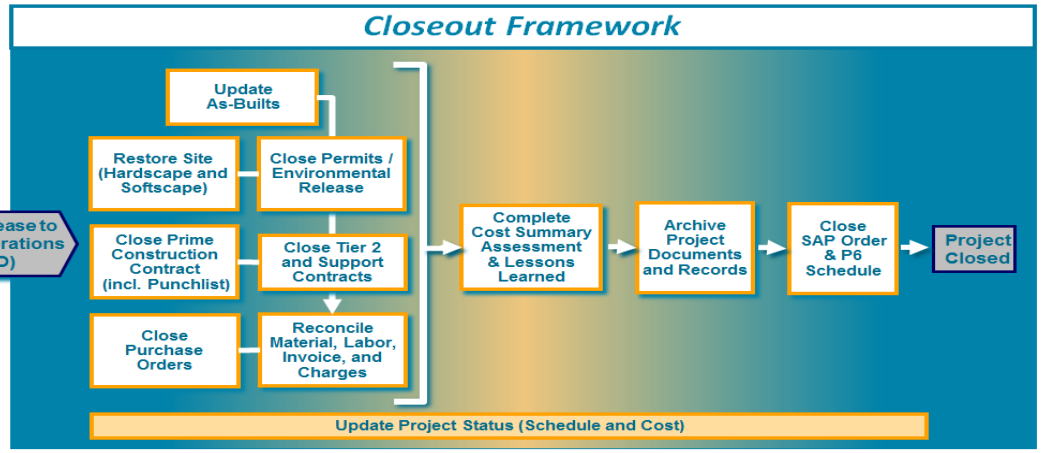
^ Job Estimate not required for expense projects with gross amount <$1M. At any time the project costs are forecasted or exceed $1M, a post JE is required and project reauthorization is required.

PDS Tool Site => http://pgeweb/gas (Gas Ops Site: Popular Searches); or https://sps.utility.pge.com/sites/GOpds/Documents/









SCALABLE & SUSTAINABLE ACCOUNTABLE & TRANSPARENT MEASURABLE & MANAGEABLE

KEY WORKFLOW ROLES

				Project Review					IFC Job Pkg / NTP		Financial Change Control			Construction			Order Close	
		Adv Auth (AA)	**Phase Gate 1:** DBM & Prelim Site/ Rte Analys	30%	**Phase Gate 2:** 60%	90%	**Phase Gate 3:** Proj Auth (PA)	PHA/ PSSR			Cont. Rel.	Re-Auth	Adj Proj Auth	Subst Compl	Punch List	RTO	Constr uction Contract Close@	Project Order Close
Applicable Constructn Resource		All	All	All	All	All	All	All	Contr	GC	All	All	All	Contr	Contr	All	Contr	All
Project Mgmt/ Controls	**PCA**	INI	INI	INI	INI	INI	INI		INI #	INI #	INI	INI	INI			INI	R&A	INI, R&A
	PM	R&A	R&A	R&A	R&A	R&A	R&A	R&A	R&A #	R&A #	R&A	R&A	R&A	R&A	R&A	R&A	R&A	R&A
	PM Sup	R&A		R&A*	R&A*	R&A*	R&A*				R&A	R&A	R&A	R&A		CC	R&A	
	PM Mgr	R&A *					R&A*				R&A*	R&A *	R&A*	CC			R&A	
Design Engine	**Proj. Eng**	CC	R&A	R&A	CC	CC	R&A*	INI	#	#	R&A*		CC	R&A	CC	R&A		R&A
	Proj. Eng Sup	CC*		R&A*	CC	CC	R&A*						CC*	CC		CC		
	Proj. Eng Mgr	CC*					R&A*						CC*					
Asset Engin	**Asset Eng**		R&A*		R&A*		R&A*											
	Asset Eng Sup		R&A*		R&A*		R&A*											
	Asset Eng Mgr		R&A*		R&A*		R&A*											
Land & Env	**Land Plannr**		R&A^	CC	R&A^	CC			CC #	CC #								
	Land Consult		R&A*^	CC	R&A*^	CC												
	EFS			CC	CC	CC			CC	CC								
Construct ion	**Const Mgr**		CC	CC	CC	CC			CC					INI	INI, R&A	R&A	CC	CC
	Contractor								R&A					R&A	R&A		R&A	
	Field Eng (FE)		CC	CC	CC	CC				R&A					INI			CC
Others	**Cont Admin**								R&A					CC			R&A	
	Estim Anlyst						R&A						R&A					
	Auth Admin Clerk	R&A					R&A				R&A	R&A						
	Others							Prcess Safety CC				Cont Spec CC	Earnd Value CC	Reg CM CC	Lead Insp CC	GPOM R&A	True-Up Anlyst R&A	Order Mgmt R&A

(**INI**) Workflow Initiator…PM may also initiate workflow in place of PCA.; (**R&A**) Review & Accept; (**CC**) Copy

(*) Delegation of Authority based on project Gross Amount

(^) if includes Site/Route Analysis

(#) Document owner uploads document(s) to Unifier

(@) Automatically initiated upon Punch List workflow completion

See WORKFLOW and CHECKLISTS in PDS Site for more details such as documents and Delegation of Authority.

SCALABLE & SUSTAINABLE ACCOUNTABLE & TRANSPARENT MEASURABLE & MANAGEABLE

PART 1: OVERVIEW

a) Best Practice: 5 **b) Status:** Pilot

Methane Evacuation Procedures

Written company procedures implementing the BPs approved for use to evacuate methane for non-emergency venting of high pressure distribution (above 60 psig), transmission or underground storage infrastructure 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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E has successfully employed methane evacuation reductions for several years, primarily on its backbone system where the largest benefits are found. To date, PG&E has employed drafting and cross compression as reduction methods.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E will develop a new standard and procedure to consider the reduction of methane evacuation during non-emergency gas transmission blowdowns, and implement reduction methods where feasible. The documents will instruct those involved in the planning and execution of planned gas transmission work to build time into project schedules to:

- Study the local gas system for each project and look for opportunities to implement reduction strategies. For example, to use drafting and, or mobile compression to reduce line pressure to the lowest operationally feasible level prior to blowdown;
- Plan the project's construction schedule around the possibility of using reduction methods, as feasible;
- Allow for adequate time during a project's clearance to employ the use of methane reduction activities as applicable; and
- Accurately measure and record both avoided and actual methane emissions for each blowdown.

There will be a phased rollout of guidance documents, initially implementing all backbone projects in 2018 and then transitioning to local transmission system in early 2019.

In addition, PG&E is performing research and development on alternative methods to reduce volume of gas from blowdown. See supplemental section below for attachments.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

None.

e) What technology is required to implement the best practice and why?

Development of the standard and procedures does not require implementation of new technology. PG&E will utilize existing drafting and compression technologies to execute the new standard and procedure and will continue assessing developmental technologies for potential future use, including but not limited to: flaring, thermal oxidation, and pipeline isolation tools. In addition, as mentioned in BPs 3, 4, 6, 7 PG&E is developing an IT solution to capture estimated emission reductions, actual

emissions reductions, and factors in determining reduction amounts.

f) Will work require additional personnel and/or contract support? If so, please provide details.
Additional resources to develop, implement, and sustain methane reductions will be required. Initial assessment suggests the need for 4.5 FTEs (Full Time Equivalent) for BP's 3-7.

g) What changes to existing operations are required? How will those changes be implemented?
The new standard and procedure will require PG&E to build additional time into project schedules to plan for and implement methane reduction strategies, including drafting and compression. PG&E will also be required to fund technology improvements and develop processes to support the calculation, tracking, and reporting of methane reductions due to the new standard and procedure.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
The new items that are required include:

- A new standard will be written noting that methane reduction must be considered for all non-emergency Gas Transmission blowdowns and implemented where feasible;
- New procedures will be written to explain how to determine feasibility and how to document reduction planning for each specific project; and
- A job aid/guidance document will be composed and circulated to stakeholders explaining the change in the process and referencing the new standard and procedures.
- BP6 references PG&E existing Gas Clearance Standard (TD-4441S) and Gas Transmission Clearance Procedures (TD-4441P-10 through TD-4441P-19), which shall be modified to reference the new standard and procedures outlined in this BP.

i) Timeline for implementation (Milestones):

Q1-Q3 2018: Develop procedures to determine reduction feasibility and method of documenting reduction planning efforts.
Q1 2018: Engage Standards team to begin working on a new standard for methane reduction
Q3 2018: Circulate procedures to management for comment and review.
Q3 2018: Implement methane reduction process for all planned transmission backbone projects
Q4 2018: Implement IT upgrade to begin automated tracking/reporting of methane reduction
Q1 2019: Execute reduction procedures for all Gas Transmission work requiring a blowdown.
Q1 2019: Finalize formal standard and procedure.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:

- Cost-effectiveness has not been fully developed for this BP, however, the feasibility for employing the use of drafting and, or compression will be based on the following factors: Environmental impacts of PG&E'smethane reduction decisions;
- Safety;
- Reliability;
- Operational Feasibility;
- Resource Availability; and
- Economic Feasibility (will consider the amount of gas to be released versus costs to retrofit site, employ additional equipment, make changes to system, etc.) – to be developed.

k) Identify any cost benefits from this BP, when cost estimates are known:

Cost benefits are not known at this time.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
Costs associated with this BP will overlap with costs associated with the implementation of BP 3 and BP 4.

m) Anticipated Emissions Reductions from this BP:
Emission reductions from this BP are unknown at this time. There is an overall goal as a part of the Methane Challenge voluntary program, which is discussed more in BP 7.

2015 Baseline Emissions affected, where known:
See PG&E's response to question m) above.

n) Calculation Methodology:
See PG&E's response to question m) above.

o) Additional Comments:
Standards, procedures and guidance documents described in this BP will likely encompass responses for several BPs (BP2 BP3, BP4, BP5, BP6, BP7 have interconnected responses).

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

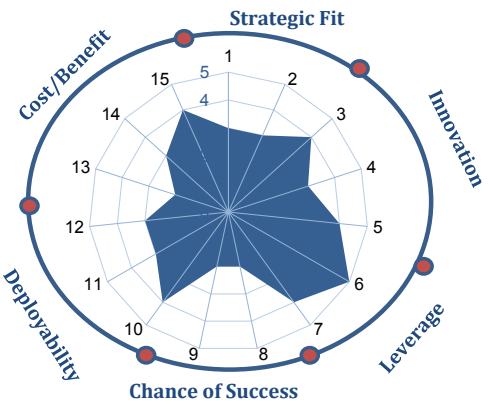
c) Research or Studies:
See attachments

- NYSEARCH project on Methane Oxidation Catalysts for Reduction of Emissions from Flaring (BP05_ATCH01); and
- OTD Project on Methods to Prevent Blowdown of Gas (BP05_ATCH02).

d) Other:
None.

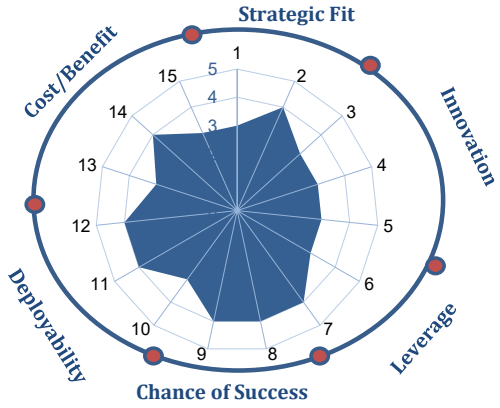
NYSEARCH June 2017 proposal: Methane Oxidation Catalysts for Reduction of Emissions in Flaring

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	In response to California SB 1371, PG&E is actively pursuing and testing methodologies and new technologies to reduce methane emissions from gas operations activities. One of the techniques to reduce emissions is to flare methane into carbon dioxide and water. The regulation for flaring varies from county to county and it is normal to have strict limitations on flaring volumes, especially in urban areas, since the process may produces pollutants such as NOx and SOx and a lot of noise. In light of this, Stanford University is looking into an alternative to flaring by catalytically oxidizing methane at lower temperatures. If successful, this technology has the potential to be a lower cost and more accessible alternative to flaring. This is an early stage science research and is expected to take some time before a prototype can be realized.	3
	How does it fit in our overall strategy and rank among our priorities?	This development is aligned with the Blowdown Emissions Reduction Team (BERT) goal of reducing emissions by at least 50% by 2020. Having more options other than flaring can help reduce the cost of emission abatement and provide more flexibility in implementation.	3
Innovation	What is the state of the art?	Currently, PG&E is still evaluating several flaring technologies for reducing blowdown emissions from transmission pipelines. There were several permitting issues encountered with California Air Resources Board which delayed initial testing. The proposed technology will be more benign to the environment and will likely meet less resistance from regulators. To reduce venting emissions from tanks and process equipment, the other option to flaring is recirculating solvent to capture methane which is very costly.	4
	What is the existing solution at PG&E?	PG&E has been active in performing cross-compression and drafting of pipeline gas to reduce blowdown emissions. In 2016, both cross-compression and drafting account for over 50% reduction of potential blowdown emissions. With the addition of flaring and oxidative catalytic technology, the number is expected to increase further.	3
	How does the team compare to competition?	The research will be led by Prof. Matteo Cargnello of Stanford University who has several years of experience in methane combustion catalysis. His group is well equipped with synthesis and characterization instruments which will be key in monitoring catalyst performance.	4
Leverage	How does the project leverage previous work?	This project will directly leverage the research performed by Prof. Matteo Cargnello in using palladium catalyst embedded on cerium oxide platform to combust methane at a high rate in 2012. Since then, Matteo has also been active in further optimizing methane combustion catalysts and has several publications on this topic.	5
	What are the opportunities of co-financing?	The cost of the project is $180,800 (for year 1 effort) and PG&E's share of the cost is $24,105 for a leverage ratio of 7.5.	4
Chance of Success	What are the risks for failure?	The risk of failure, as with any basic science research, is high. The challenge is to bring the reaction rate of the catalyst high enough to be able to break down large amount of methane quickly and safely. In addition, there may be a risk of incomplete oxidation which can generate pollutants. NYSEARCH is mitigating these risks by placing a go/no-go step at the end of year 1 and only charging members for the Year 1 cost. There will be a review at the end of Year 1 to evaluate the research potential.	2
	What are the requirements for deployment at PG&E?	The requirement for deployment is extensive field testing and safety verification by independent testing agencies.	2
Deployability	How will the solution be used?	Depending on the oxidation rate and cost of the technology, the eventual use ranges from complete replacement of flaring to a substitute in areas where regulations are very limiting. The application can be to reduce blowdown and venting emissions from pipelines, process equipment and high bleed components.	4
	What additional delays have to be accounted for the full deployment?	The technology once proven will have to be industrialized with the help of a commercialization partner. In addition, regulators will need to be informed of this novel technology to permit its use. Finally the safety and environmental impact of the technology will have to be examined prior to field testing.	3
	How does it synchronize with existing actions?	This project is in line with our efforts on understanding and reducing emissions which include leak quantification projects at NYSEARCH, using in-line stopple to reduce blowdown emissions.	3
Cost vs Benefits	Can we assess cost benefits of the solution?	The benefit of the solution is to provide more tools to reducing emissions from various sources. It is difficult to estimate the quantitative value of the solution at this point.	2
	What will the on-going cost of the solution after deployment be?	On-going costs of the UAS is still unclear at this point. It is likely that there will be maintenance costs involved with catalyst replacement or regeneration.	3
	What is an acceptable cost target for PG&E?	$30,000 as an initial seed money to evaluate the feasibility of this idea is a reasonable cost for PG&E.	4
		Total	**3.3**



2016 Spring OTD project proposal (5.16.n): Methods to Prevent Blowdown of Gas

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	To meet the goals of Senate Bill 1371, CPUC is pushing utilities to curb methane emissions. Based on gas utilities' 2014 data, one of the biggest sources of emissions was transmission pipeline blowdowns. To date, PG&E has started to explore the use of candle stick flare to reduce emissions but there remains a need to find alternative flaring solutions in places where open flame is not permitted such as urban areas. In addition, PG&E has also implemented cross-compression and drafting to prevent blowdown of gas. This OTD project will investigate other flaring and cross compression options and help PG&E identify technologies for use in different scenarios. benchmark with the industry. The project will also help PG&E benchmark with the industry.	3
	How does it fit in our overall strategy and rank among our priorities?	SB 1371 has brought methane emissions into the spotlight. In addition to being safe, reliable and affordable, there is now an additional need to deliver gas in an environmentally sustainable way.	4
Innovation	What is the state of the art?	GTI will investigate state-of-the-art technologies for flaring and cross-compressing in various conditions: e.g. urban (where open flame is not permitted).	3
	What is the existing solution at PG&E?	PG&E is performing flaring pilots in 2016. The first pilot was completed in March in Hinkley with candle stick flare and the next one will be at Gridley. In addition, the team has also used cross-compression and drafting in the past to reduce emissions from blowdown.	3
	How does the team compare to competition?	GTI has worked on a number of projects related to curbing methane emissions such as developing a methane flow rate measurement device, Hi-Flow Sampler and developing emission factors for underground distribution pipe leaks for the industry.	3
Leverage	How does the project leverage previous work?	This project will leverage experience from other utilities and will also add to the experience that PG&E has accumulated through the flaring pilots and use of cross-compression technology.	3
	What are the opportunities of co-financing?	The total cost for this one-year project is $105,000. Assuming 4 utilities will fund the project, the shared cost for PG&E is $26k.	4
Chance of Success	What are the risks for failure?	The only risk of failure is if the project takes too long to complete and might serve as an afterthought instead of providing information to drive our decisions. A request has been made to GTI to accelerate this effort and they agreed to push the schedule.	4
	What are the requirements for deployment at PG&E?	There is no requirement for deployment. Findings from the project will be disseminated to subject matter experts within the company.	4
Deployability	How will the solution be used?	The project findings will be used as valuable information by our subject matter experts to decide the type of methods that they will select to minimize emissions from blowdowns.	3
	What additional delays have to be accounted for the full deployment?	No additional delay is expected.	4
	How does it synchronize with existing actions?	This project synchronizes with PG&E's intent to reduce emissions from blowdowns by at least 50% by 2018. An internal team has been set up to address this goal and senior leadership is in the process of publishing a new set of policy to express the company's intent.	4
Cost vs Benefits	Can we assess cost benefits of the solution?	This study will inform us about the best options for reducing methane emissions from blowdowns which is expected to become more relevant with greater pressure from federal and state agencies to minimize environmental impact.	3
	What will the on-going cost of the solution after deployment be?	There will be no ongoing cost associated with deployment of the results. The results will inform our team of the options available to minimize emissions from blowdowns.	4
	What is an acceptable cost target for PG&E?	$26k is an acceptable cost for PG&E considering the long term potential this project has to update our operating procedure.	3
		Total	**3.5**



PART 1: OVERVIEW

a) Best Practice: 6 **b) Status:** In progress

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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E has a standard and procedure for the Gas Transmission Clearance process. The procedure explains what information to include in Work Clearance Documents, how to write them, and how to obtain approval for them.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E has an existing Gas Clearance Standard (TD-4441S) and Gas Transmission Clearance Procedures (TD-4441P-10 through TD-4441P-19), which shall be modified to reference the new standard and procedures proposed in BP 3 and BP 5 regarding the required reduction of methane blowdown where feasible. Procedures should be updated to clearly list steps required to achieve methane reduction in Work Clearance Documents. PG&E plans to complete updates to the existing standard and procedures as applicable in parallel with the development of new standard and procedures for BP 3 and BP 5 which are estimated to be completed in 2019.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

None.

e) What technology is required to implement the best practice and why?

None.

f) Will work require additional personnel and/or contract support? If so, please provide details.

This work does not require additional personnel.

g) What changes to existing operations are required? How will those changes be implemented?

There will only be minor updates to reference the new BP 3 and BP 5 standard and procedures in Standard TD-4441S and slight modifications to existing Gas Transmission Clearance procedures to more clearly list out the steps and timeline of methane reduction to occur during a clearance. This should not affect existing operations.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.

Gas Clearance Standard TD-4441S and Gas Transmission Clearance procedures TD-4441P-10 through TD-4441P-19 will be modified as applicable in parallel with the creation of the new standard and procedures

for BP 3 and BP 5.

i) Timeline for implementation (Milestones):
In parallel with BP 3 and 5 standard development;
Q3-4 2018: Review Gas Clearance Standard TD-4441S and Gas Transmission Clearance procedures TD-4441P-10 through TD-4441P-19 for potential updates.
Q1-2 2019: Finalize updates to TD-4441S and TD-4441P-10 through TD-4441P-19 as applicable.
Q1 2019: New standard and procedures for BP #3 and #5 are completed.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
Due to the limited cost implications associated with this modification to existing procedures, cost-effectiveness factors have not been considered at this time.

k) Identify any cost benefits from this BP, when cost estimates are known:
Cost benefits are unknown at this time.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
Incremental costs or benefits are unknown at this time.

m) Anticipated Emissions Reductions from this BP:
Emission reductions from this BP are unknown at this time. There is an overall goal as a part of the Methane Challenge voluntary program, which is discussed more in BP 7.

2015 Baseline Emissions affected, where known:
See PG&E's response to question m) above.

n) Calculation Methodology:
See PG&E's response to question m) above.

o) Additional Comments:
Standards, procedures and guidance documents described in this BP will likely encompass responses for several BPs (BP2, BP3, BP4, BP5, BP6 BP7 have interconnected responses).

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies: None.
d) Other: None.

PART 1: OVERVIEW

a) Best Practice: 7 **b) Status:** In progress

Bundling Work Policy

Written company policy requiring bundling of work, whenever practicable, to prevent multiple venting of the same piping consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Company policy shall define situations where work bundling is not practicable. Exact wording TBD by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

Gas Transmission Project Delivery last updated the project bundling guidance document in May 2017; it is currently focused on the efficiency gains of bundling work and the procedural steps in properly accounting for costs when bundling work funded by different work streams.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

In order for PG&E to meet its sustainability goals and comply with SB 1371 and SB 1383, PG&E will develop a new standard and procedures to reduce the emission of methane during non-emergency Gas Transmission blowdowns, and implement reduction methods including planned work bundling to the maximum amount possible while not compromising the safety and reliability of its gas system. In addition to these actions, PG&E will update its Gas Transmission Project Delivery bundling guidance document used by their gas transmission project management group to include steps to be taken to assess the feasibility of bundling planned work to reduce methane emissions. Assessment will include:

1) Feasibility assessment of bundling work and use of other methane reduction strategies and documentation of findings;
2) Calculation and documentation of potential bundled project methane reductions;
3) Documentation of reasons for work falling out of bundle; and
4) Calculation and reporting of actual methane reductions as a result of bundling work.

PG&E plans to implement a full complement of methane reduction strategies across PG&E's entire transmission system in mid to late 2018. A phased rollout of guidance documents initially implementing with all backbone projects and transitioning to local transmission system in early 2019. The project bundling guidance document update will be included in this phased rollout. See supplemental section below for details on the existing documents.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

None.

e) What technology is required to implement the best practice and why?

As mentioned in BPs 3, 4, 6, 7 PG&E is developing an IT solution to capture estimated emission reductions, actual emissions reductions, and factors in determining reduction amounts.

f) Will work require additional personnel and/or contract support? If so, please provide details.

Additional resources to develop, implement, and sustain methane reductions will be required. Initial

assessment suggests the need for a consolidated resource requirement of 4.5 FTEs for BP's 3-7.

g) What changes to existing operations are required? How will those changes be implemented?
The updates that will be made to the existing project bundling guidance documents will incorporate identification of potential methane reduction projects into the project planning and bundling process, evaluate the use of bundling and other reduction strategies on a per project basis well in advance of project execution, and develop and deploy enhanced processes to calculate volumes, capture pressures, calculate reductions, quality control of data gathered and report out reduction achievements.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
The new items that will be added are:

- A new standard will be written noting that methane reduction must be considered for all non-emergency Gas Transmission blowdowns and implemented where feasible;
- New procedures will be written to explain how to determine feasibility of bundling and other methane reduction strategies and how to document reduction planning for each specific project;
- A job aid or guidance document will be composed and circulated to stakeholders explaining the change in the process and referencing the new standard and procedures; and
- A quality control process will be developed and implemented to ensure PG&E follows the bundling guidance for reduction strategies and accurately reports reductions.

i) Timeline for implementation (Milestones):
Q1-Q3 2018: Develop procedures to determine reduction feasibility and method of documenting reduction planning efforts.
Q1 2018: Engage Standards team to begin working on a new standard for methane reduction
Q3 2018: Circulate procedures to management for comment/review.
Q4 2018: Implement IT upgrade to begin automated tracking/reporting of methane reduction
Q1 2019: Execute reduction procedures for all Gas Transmission work requiring a blowdown.
Q1 2019: Finalize formal standard and guidance document.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
Cost estimates have not been fully developed for this BP, but the feasibility for employing the use of bundling will be based on the following:

- Percentage of total project cost;
- Methane reduction opportunity versus reasonable costs of reduction effort;
- Customer impacts;
- Power generator impacts;
- Weather impacts; and
- Economic Feasibility (will consider the amount of gas to be released versus costs to retrofit site, employ additional equipment, make changes to system, etc.) – to be developed.

k) Identify any cost benefits from this BP, when cost estimates are known:
PG&E estimates cost savings from emissions abatement for gas transmission is calculated using the price of gas at the City Gate ($3.30/Mscf), while estimated cost savings for gas distribution emissions abatement is calculated using retail price of gas ($20.70/Mscf).

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
Costs from methane reduction efforts will not overlap with costs from PG&E's current gas release tracking process.

m) Anticipated Emissions Reductions from this BP:
Emission reductions from this BP are unknown at this time. Currently PG&E's goal through the Methane Challenge voluntary program is an abatement of 50% of potential gas release from transmission pipeline clearances. This goal applied to the average activity over the past years (2015 and 2016) as reported to the CPUC under OIR 15-01-008 represents a methane abatement of 0.24 Bcf/yr. Abatement feasibility and effectiveness highly depends on the nature of the work and the type of assets. Typically, maintenance work, such as valve replacement and hydrotest, has a larger potential for emissions compared to inline inspections that requires only limited blow-down. Large backbone transmission pipelines present better abatement potential than local transmission pipelines because of their larger volume and pressure. The portfolio of work varies from year to year in term of assets and nature of the work. PG&E will develop metrics that adequately drive performance based on the feasibility and effectiveness of blow-down reduction for these different cases. This comment covers BP 2, 3, 4, 5, 6, and 7.

2015 Baseline Emissions affected, where known:
See PG&E's response to question m) above.

n) Calculation Methodology:
See PG&E's response to question m) above.

o) Additional Comments:
Standards, procedures and guidance documents described in this BP will likely encompass responses for several BPs (BP2, BP3, BP4, BP5, BP6, BP7 have interconnected responses).

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
See attached Gas Transmission Project Delivery bundling guidance document (BP07_ATCH01), section to be added to address the process and actions surrounding the bundling of work to reduce methane emissions.

c) Research or Studies:
None.

d) Other:
None.

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PROJECT BUNDLE GUIDELINES

I. SUMMARY

Planning and executing projects in a bundle can result in such benefits as improved resource and schedule efficiencies, cost savings and/or minimization of impacts to customers. This document provides guidelines for the set-up, planning and execution of Project Bundles to standardize the process for 1) consistency and continuous improvement, 2) alignment of project systems, 3) integration with the Project Delivery System (PDS), 4) compliance with Capital Accounting guidelines, regulatory rules and Business Finance processes, and 5) driving efficiency overall as one Gas Operations organization.

A Project Bundle (PB) referenced in this guideline meets all of the following criteria:

- Two or more orders (capital and/or expense) from one or more Gas Transmission regulatory programs
- An upfront assignment or allocation of PB construction common costs
- One prime construction resource
- One Contract Work Authorization (CWA) for contracted work
- Justification to combine and coordinate the project work together

A project(s) that is to be proposed to be included in or excluded from a PB requires informing the Project Bundle Program Specialist for acceptance.

Examples of Project Bundles (not all inclusive) applicable to this guideline:

Regulatory Program(s)	Project Bundle Orders	Follows Guidelines
Strength Test	Capital and Expense	Yes
Pipe Replacement and ILI Upgrades	Capital	Yes
Station, Valve Replacement, Digs	Capital and Expense	Yes

Common Costs are defined as the construction costs that are either shared (allocated by a pre-determined percentage) by the projects in a Common Order (previously known as a geographic) PB OR incurred solely by the Primary Project in a Primary Order (previously known as an asset) PB. Any other projects in a Primary Order PB with incremental work do not incur any of the construction common costs. Other costs that do not occur in the construction phase such as design, permitting and pre-planning, are not considered common costs for purpose of this guideline in order to provide basic implementation and emphasize the more significant savings in construction. Sharing or assigning the construction common costs in project bundling, regardless of PB type, will drive efficiency and cost savings.

PB Common Costs:

- Mobilization/Demobilization
- Laydown Yard/Construction Yard
- CNG/LNG
- Trailers
- Construction Project Management

Acceptance of the PB Plan Form and PB Instructions are elements of the PB process to support administrative consistency and stakeholder communication. Changes occurring to the PB must follow the established change management processes.

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PROJECT BUNDLE GUIDELINES

Project Bundles are generally categorized by two types:

	Project Bundle Methods	
	Common Order Method (COM)	**Primary Order Method (POM)**
Key Element	All the projects in the Project Bundle are allocated a percentage of the construction Common Costs using a Common Cost Order.	A Primary Project is the key driver of the Project Bundle and incurs all the construction Common Costs. Only acceptable PBs to utilize the Primary Order method: • ILI Upgrades and Strength Test • By Justified Driver exception process
Description	Projects are in the same general vicinity so that project planning and execution elements such as sharing resources, obtaining land use and permits, and managing the work with increased efficiencies and flexibility, can be planned and executed to achieve overall better results than if all the projects in the PB were planned and executed as stand-alone projects.	Projects share or overlap work on a particular asset. The work on the Primary Project would occur regardless of the additional projects in the bundle. Therefore, an asset-based primary project is often designed and executed, incurring all common costs, while work on the other projects in the bundle are considered "incremental" and only incur the incremental costs to plan and execute their respective projects.
Pre-requisite	Stand-alone construction estimates for (for GC work) or fully executed CWA (for contracted work) each project in the bundle	The Primary Project is determined based on, in order, 1) Compliance requirement, 2) Rate Case commitment, 3) other justified driver
Common Cost Order Set-up and Charges	• Single Common Cost order • All projects in the bundle are allocated a percentage of the construction Common Costs • Allocation percentages determined from stand-alone construction estimates or CWA	• Common Cost order is NOT required • Primary Project incurs all of the construction Common Costs • Common costs are charged directly to the Primary Project order
Non-Common and Specific Order Charges	Charged directly to the applicable specific orders in the bundle	Charged directly to the Primary Project or applicable specific orders for incremental work
Journal Entries	• Monthly from Common Cost Order to specific project bundle orders • Used for corrections	• Not required • Used for corrections
Project Bundle Plan	Acceptance required prior to Common Cost Order is open for charges and prior to the first mobilization date of the PB	Acceptance required for the Primary Project determination and prior to the first mobilization date of the PB
Changes to the Accepted Project Bundle Plan	• After a PB Plan is approved, updates to the allocation percentages shall be required, effective from the date the revised PB Plan is approved, if any of the following occur: ✓ A project is added or deleted ✓ Total PB Common Costs to date is greater than $1M AND the cumulative amount of change orders for any PB order is greater than $1M • Costs previously allocated will not be modified retroactively	• In the unlikely case that the Primary Project is changed, previously allocated costs may need to be modified

PROJECT BUNDLE GUIDELINES

II. TARGET AUDIENCE

Gas Operations Transmission Project Managers, Lead Engineers, Contracts Specialists, PCAs, Land Planners, Environmental Field Specialists, Construction Managers, Field Engineers, Risk Specialists, Schedulers, Business Finance, Capital Accounting, Project Bundle Program Team

III. PROJECT BUNDLE KEY ASSUMPTIONS

- Project Bundles may have unique drivers and benefits. Examples include:
  - ✓ Reduced impact to customers and the community
  - ✓ Shared clearances for efficiency and to minimize gas blowdowns
  - ✓ Improved resource utilization
  - ✓ Increased longer-term commitment from welders and other construction resources
  - ✓ Coordination of efforts and utilization of permits
  - ✓ Limit needs for land acquisition and sharing of laydown yards
- PG&E Gas Operations will realize the most significant efficiency and cost savings gains related to Construction. Some functional organizations may have an increase in workload for the overall PB benefits and cost savings
- Efficiency gains are realized as a collective effort. Emphasis is placed on managing more at the portfolio/program level vs. the project level
- The total cost to any project in a PB will not exceed the stand-alone project costs if it were executed as a stand-alone project
- Actual cost savings and bundle justification cannot be fully determined due to the varied timing of estimates but a rough determination can be made
- Workstreams are accountable, throughout the project's lifecycle, for their respective project order authorization and funding
- The Project Bundle Plan, including the methodology for charging and allocating costs, is accepted prior to the first project's construction mobilization

BEST PRACTICE:
Workstream or functional organizations assign or re assign the number of their personnel for each Project Bundle. For example, a Project Bundle with1 PM representing 3 strength test projects is likely to be more efficient than 3 PMs (a different PM for each strength test project) for the one Project Bundle.

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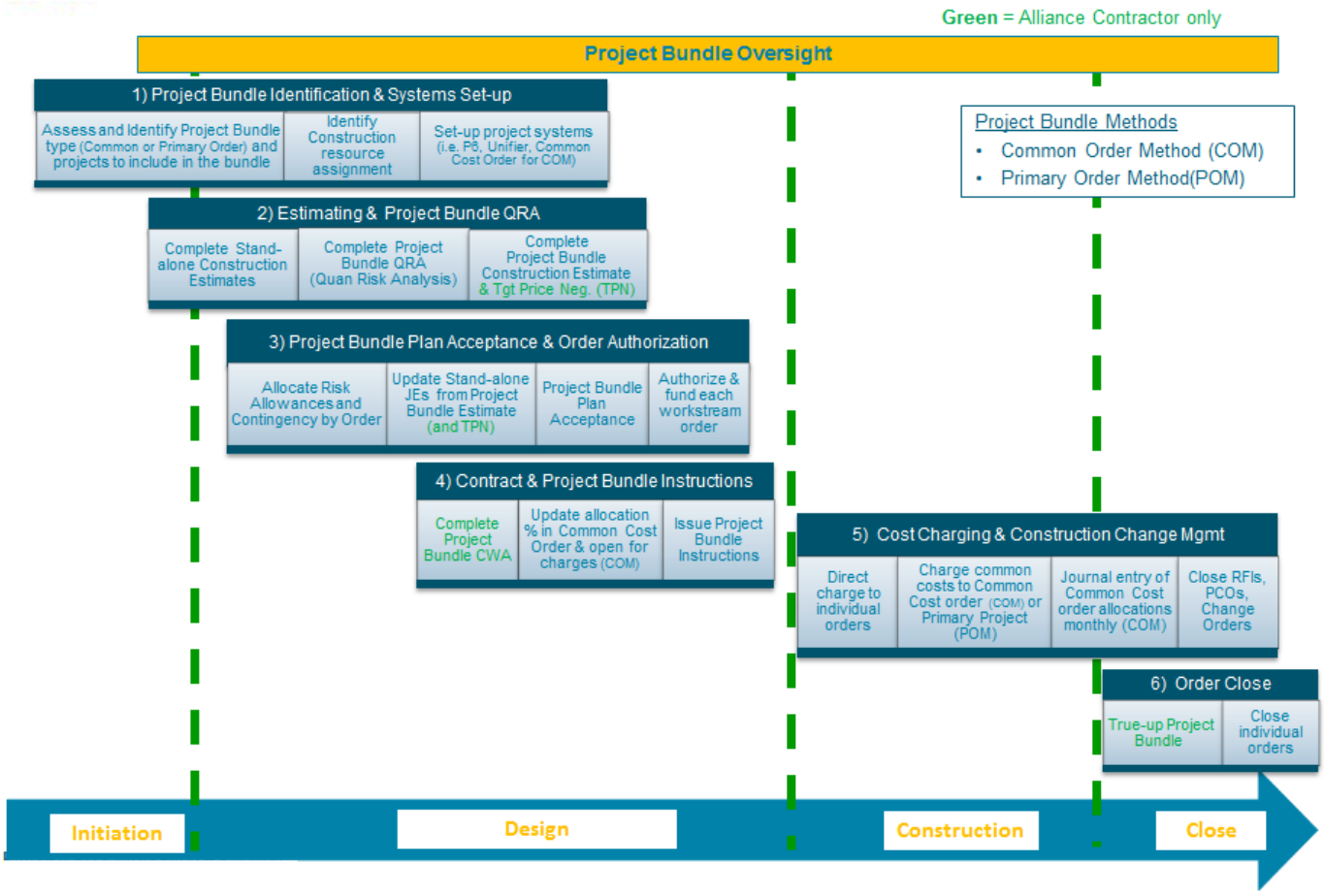
PROJECT BUNDLE GUIDELINES

IV. TIMELINE OF ACTIVITIES

The following "buckets" of work for a PB highlights the key activities. Activities are not necessarily completed in a sequential order and may be performed concurrently.



PROJECT BUNDLE GUIDELINES

V. ROLES & RESPONSIBILITIES

Role	Responsibilities
Asset Engineer	▪ Identify projects to include in a PB for design and execution ▪ Participate and coordinate PB planning with Project Bundle Program leads
PB Program Manager	▪ Ensure PB process, forms and guidelines are current and followed ▪ Address Primary Project determination conflicts, if applicable, and escalate to Integrity Mgmt Director to resolve any Primary Project identification issues (POM) ▪ Report PB status and benefits
PB Program Specialist	▪ Follow PB process ▪ Identify projects and assess readiness to be included in each PB ▪ Facilitation of identifying Primary Project (POM) ▪ Facilitate concurrence of projects to be in each PB with key stakeholders (Asset Engineers, Design Engineering, Land, Environmental, Materials, Construction) ▪ Request Common Cost Order creation, allocation set-up, and initiate order to receive charges ▪ Facilitate Construction Resource identification ▪ Ensure Project Bundle Plan acceptance in EDRS ▪ Facilitate updates to Project Bundle Plan, Plan acceptance, Common Cost orders, PB Instructions
PB Lead PM (POM) / PB Program Lead (COM)	▪ Oversee Master Schedule ▪ Facilitate and manage PB Risk Register (POM) ▪ Facilitate PB QRA for bundles > $5M ▪ Inform PB Program Team of changes to projects in PB ▪ Complete and issue Project Bundle Instructions to stakeholders ▪ Communicate monthly forecasts and change order impact for Common Cost order for respective orders (COM) ▪ Ensure monthly Common Cost journal entry approvals and allocation are completed (COM) ▪ Ensure SPSI phase gate controls are executed for Common Cost Order to only allow Common Cost operations per the Schedule of Values internal costs. For external costs, monitor appropriate SPSI charging. ▪ Facilitate and escalate scope, schedule cost concerns in a timely manner ▪ Facilitate PB Lessons Learned ▪ Inform all PB Workstream PMs and Business Finance when individual orders can be closed and ensure timely closeout of orders, including Common Cost order (COM) ▪ Confer with and facilitate meetings with Capital Accounting and Business Finance, as needed, regarding cost allocation concerns or discrepancies ▪ Report monthly forecast of Common Cost allocation to Business Finance
PB Lead PCA	▪ Facilitates reports for Project Bundle status
Workstream Project Mgr	▪ Manage individual Workstream orders ▪ Coordinate order-specific work with other Workstream PB project managers to help achieve bundle efficiencies ▪ Report out to PB Lead PM / Program Lead
Workstream PCA	▪ Ensures proper charging to orders ▪ Forecast Workstream orders ▪ Receive authorization / funding for Workstream orders ▪ Ensures order is not closed until PB true-up is complete (Alliance Contractor)
Business Finance Analyst	▪ Perform manual journal entries as necessary to true up costs prior to automation ▪ Review PB Plan for appropriate approvals and documentation prior to adding new entries to automation template ▪ Update automation journal entry template once PB Plan is approved ▪ Review monthly forecasts to determine if additional approval for recurring entries is required ▪ Close Common Cost order

PROJECT BUNDLE GUIDELINES

PB Functional Lead - Engineering, Land Planning, Scheduling, Estimating, Contracts, Const. Mgmt, EFS, Clearance Planning	▪ Actively seek functional efficiencies in support of the bundle ▪ PB Point of Contact and facilitator to oversee and coordinate their respective function across PB orders

VI. PROJECT BUNDLE INDENTIFICATION AND SYSTEMS SET-UP

Upon evaluating the planned readiness and determining which projects will be bundled together, it is necessary to set up a PB in the various project delivery systems.

A) P6 Schedule

Request Project Bundle Master Scheduler to:

1) Create Bundle # (PB-###)
2) Name PB using the following naming convention:

   PB-###_ Region(s)_Bundle Type (Examples: PB-010 Central Valley POM, PB-004 Bay North COM)
3) Modify N.# for all projects in the PB to a the same number, if applicable
4) Add PB-### at the end of all P6 project names that are in the project bundle for keyword searches

B) Common Cost Order [for COM only]

Request via FCC2 (Financial Change Control)

1) Create PB Common Cost Order

- Charges are not allowed (SAP status 10) until the PB Plan has been accepted and allocation percentages are assigned for monthly automated journal entries
- Common Cost SPSI codes must match the Schedule of Values/Work Plan and phase gate controls executed.
- PB Plan must be fully accepted in EDRS with approved allocation percentages by Business Day -7 for the automated journal entry to be effective for that month
- If Common Cost charges are incurred prior to the automated journal entry set-up, the true-up manual journal entry process is needed prior to activating the automated process.
- Order is an unfunded pass through Common Cost order to be cleared out monthly via a journal entry process based on the accepted PB Plan allocation percentages
- Responsible Cost Center (RCC) is the Project Bundle Program Team with the following MAT Codes:

Project Bundle Components	Common Cost Order MAT Code
All Capital projects	12A
Capital and Expense projects	AB1
All Expense projects	AB1

PROJECT BUNDLE GUIDELINES

C) Unifier [for COM only]

Request Unifier Team to:

1) Create a project using the PB ID # and PB naming convention:
   PB-###_ Region(s)_Bundle Type (Examples: PB-015 Central Valley COM, PB-004 Bay North COM)
2) Turn off the automated PCO authorization amount constraints in the Common Cost order workflow so as to not impact processing
3) Add the respective project functional leads for this PB ID

The Unifier Common Cost order, utilizing the PB ID#, will have its own Unifier environment, containing:

- Bid Package
- Contract Workflow
- Fully Executed CWA
- Final True-Up (upon completion of all projects)

PROJECT BUNDLE GUIDELINES

VII. ESTIMATING AND PROJECT BUNDLE QRA (QUANTITATIVE RISK ANALYSIS)

A) ESTIMATING

Job Estimates (JE) for PBs will follow PDS guidelines but will also require special treatment due to the need to use them to support allocation methods of construction common costs.

The following estimates are required for Project Bundles:

Type	Description	Target Estimate Class
Stand-alone Construction Estimates	Stand-alone construction estimates are required for each individual order and are based on the assumption the work in the bundle is **NOT** performed as a part of a bundle. For these estimates, the estimator should assume **no cost efficiencies** associated with permitting, land, and construction are achieved from work performed on individual orders in the bundle. Stand-alone estimates only need to be Base Estimates and do not need to include AACE Allowances, Risk Allowances or Contingency for allocation purposes.	Class 4 (30% Design) or better
Project Bundle Construction Estimates	A single preliminary PB construction estimate will be required for the entire bundle and **WILL** assume all identified cost efficiencies available if the work is performed as a bundle. This estimate will be used to support Target Price Negotiations or review of bids if the work is issued for bidding. It will be used in the Bundle QRA process. It will not be used for individual project authorizations.	Class 3 (Prior to Target Price Negotiations) or better
Final Job Estimates for Order Authorization	Each individual order will require a Final Job Estimate for funding and project authorization. The Final Job Estimate for Authorization will be an updated Job Estimate for each individual order and include the Base Estimate, Risk and AACE Allowance and Contingency (from the PB QRA). The allowances and contingency for each Final Job Estimate for Authorization will be based on the allocation percentages, unless there is otherwise an agreement by impacted Workstream Managers.	

B) PROJECT BUNDLE QRA

The PMs for each order in the bundle are responsible to prepare separate Risk Registers that identify, track and manage risks specific to the work associated with their order(s). It is these individual Risk Registers that feed the PB Risk Register. An analysis of risks, specific to the bundle, will also be assessed to define any risks resulting from the bundling of the projects. A QRA will be conducted incorporating the individual order risks as well as those risks that may occur due to the bundling of the work. This analysis will be used as part of the assessment of the appropriate level of Risk Allowance and Contingency for the PB. After completion of the PB QRA, the PB

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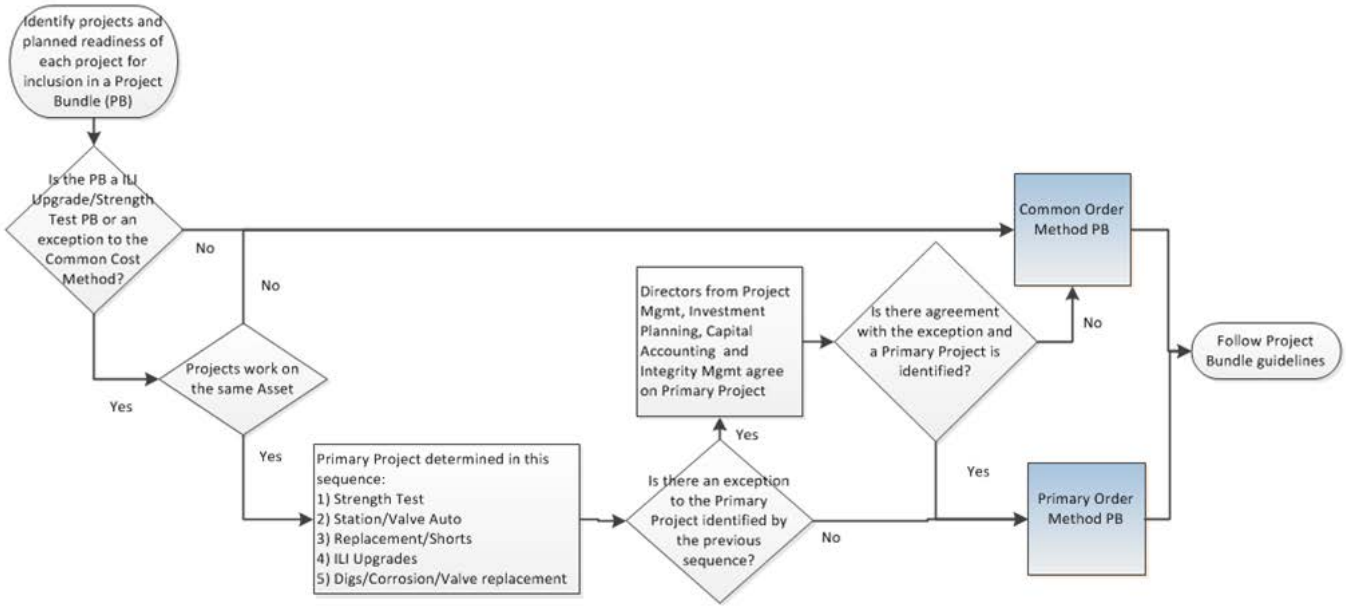
Program Team will make recommendations of the AACE Allowance, Risk Allowance and Contingency for each of the individual orders in the bundle. The default is to allocate allowances and contingency based on the percentages in the PB Plan acceptance, unless there is agreement otherwise. Workstream managers will use the agreed upon information from the Bundle QRA to set individual order AACE Allowance, Risk Allowance and Contingencies to authorize and fund for each individual order.

VIII. PROJECT BUNDLE PLAN ACCEPTANCE & ORDER AUTHORIZATION

A) PROJECT BUNDLE PLAN ACCEPTANCE

The PB Plan must be accepted prior to the start of the first construction mobilization date. The acceptance of the PB Plan provides clarity and agreement to the terms of the bundle and the upfront acceptance by impacted Workstream managers of the Common Costs allocation percentages or Primary Project.

Here is the methodology for determining PB Method and determination of the Primary Project, if applicable:



For COM PBs, allocation percentages are based by the following calculation per the CWA:

Direct charge amount per project
---------- = Allocation %
Total PB Direct Charge Amount

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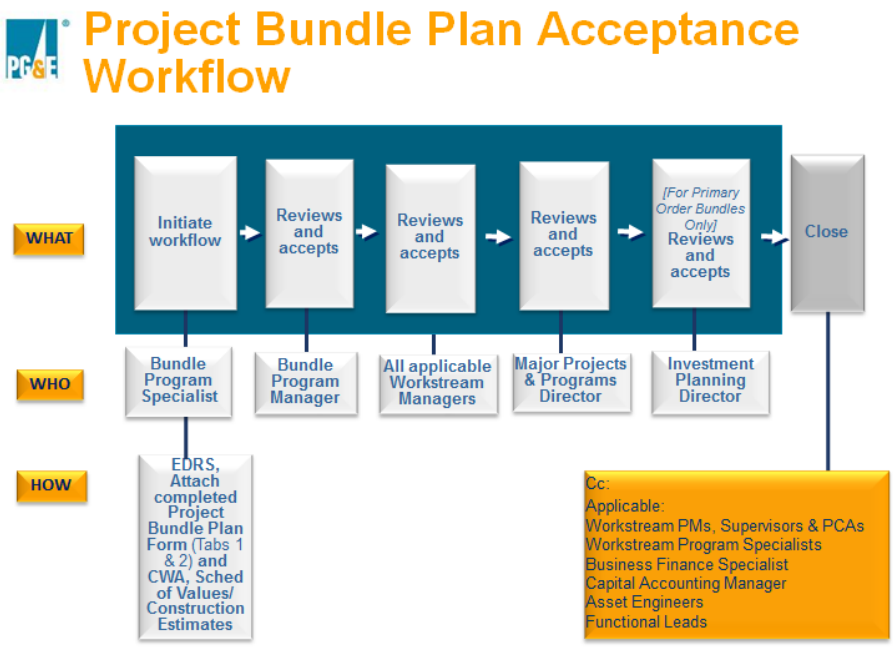
PROJECT BUNDLE GUIDELINES

	Construction Estimate Direct Costs	Allocation %
D-603A	$1.0	7%
D-603B	$2.0	14%
RT-661	$1.0	7%
T-104B	$3.0	21%
I-052	$2.0	14%
R-837	$5.0	36%
	$14.0	1.00

Upon determination of the PB method and allocation percentages, the completed PB Plan Form and supporting stand-alone construction estimates (For contracted work, attach fully executed CWA with Schedule of Values) are routed via the Project Bundle Plan Acceptance workflow.

Click Here for Project Bundle Plan Form

Project Bundle Plan Acceptance Workflow:



See Section XII below for processing changes to a previously accepted Project Bundle Plan.

B) ORDER AUTHORIZATION & FUNDING

Upon PB Form acceptance, each work Workstream is responsible for authorizing, funding and managing their respective orders. Each individual order in the bundle will require their own funding and routed through separate authorization workflow processes. The only exception is the Common Cost order, which is not funded but will serve to collect common costs which will be allocated monthly to individual orders in a COM PB.

PROJECT BUNDLE GUIDELINES

Risk reserves and contingency management for the bundle will be managed at the individual order through the normal Unifier process. Any CWA change order will allocate costs to the appropriate individual orders funded from available risk allowances or contingencies at the individual order level. Any individual order that requires funding in excess of authorized amounts and contingencies will be required to follow the normal reauthorization process to obtain funding from the affected Workstream.

The Executive Project Committee (EPC) process will be followed based on the individual project Job Estimates. If a PB is $20M or greater, the entire PB does not need to follow the EPC process – only the individual projects that do meet the EPC requirement.

IX. CONTRACT & PROJECT BUNDLE INSTRUCTIONS

A) CONTRACT

For PB work assigned to a construction contractor, unless otherwise determined, will have a single CWA and be the terms of the PB work. The cost efficiencies from bundling projects are optimized through negotiations of the entire bundle as one package. A PB Contract Specialist will be identified to coordinate the contracting process to assist in achieving the intended cost efficiencies through the PB delivery approach.

When a single CWA is used with an Alliance contractor, the Target Price Negotiations (TPN) will occur on the entire bundle and not separate TPNs for each order. The TPN may involve discussions around the various components of the bundle, but the ultimate goal of the TPN is to capture efficiencies during the TPN as a result of the PB delivery method. A Target Price Analyst (TPA) may be requested for PBs with abnormal complexity, high value, or unique characteristics, by following the established Estimating notification and coordination process.

It is critical that the CWA capture and reflect the requirements **accepted in the Project Bundle Plan**. The contractor must be given clear instructions on how to properly capture and invoice for costs to comply with capital accounting and rate case requirements.

BEST PRACTICE:

Individual projects with high uncertainty or high risk for execution should be excluded from the project bundle prior to Target Price Negotiations/Project Bundle Plan Acceptance. If the project does become viable later then it may be included via change order. Projects in a bundle that are included in a project bundle but are not ready at the time of execution may reduce any efficiencies and may actually increase costs or have other negative impacts to planned bundle benefits.

PROJECT BUNDLE GUIDELINES

B) PROJECT BUNDLE INSTRUCTIONS

PB Instructions provide stakeholders involved in the PB execution with the necessary information for each unique PB. Instructions include key contacts, exceptional charging instructions and closeout requirements.

Click Here for Project Bundle Instructions Template

PB Instructions should be issued and reviewed at the Project Review meeting(s) or the Pre-Construction meetings, at the latest.

X. COST CHARGING AND CONSTRUCTION CHANGE MANAGMENT

A) COST CHARGING

PBs, which may have a mix of orders which include Capital and Expense and/or multiple Workstreams orders, require special attention for proper assignment of costs to the appropriate cost categories (e.g. capital vs expense, Workstreams, etc.) in order to comply with Capital Accounting rules and Business Finance monitoring. Activities which benefit multiple Workstreams must be tracked in a way that allows allocation to the appropriate Workstreams.

To the maximum extent practical, costs associated with an individual order should be direct charged to the applicable order. Common costs that cannot be directly attributable to a single order and apply to multiple orders (e.g., mobilization, demobilization, common construction support, etc.) should be charged to the Common Cost order for the Common Order Method or the Primary Project for Primary Order Method bundles, in accordance with the accepted PB Plan.

CHARGES	Common Order Method	Primary Order Method
To Individual Applicable Order	Design Engineering Project Mgmt Project Controls Contracts Permits Environmental Mgmt Land Mgmt Land Acquisition Materials Pre-NTP Pre-Construction Planning Order-specific Construction Costs	Design Engineering Project Mgmt Project Controls Contracts Permits Environmental Mgmt Land Mgmt Land Acquisition Materials Pre-NTP Pre-Construction Planning Order-specific Construction Costs
To Common Cost Order	Mobilization/Demobilization Laydown Yard / Construction Yard CNG/LNG Trailers Construction Project Mgmt	n/a
To Primary Project Order	n/a	Mobilization/Demobilization Laydown Yard / Construction Yard CNG/LNG Trailers Construction Project Mgmt

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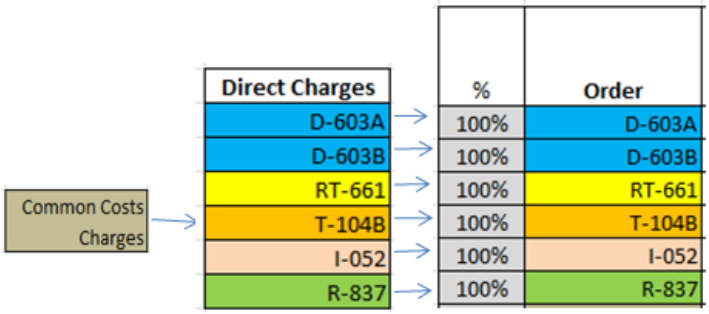
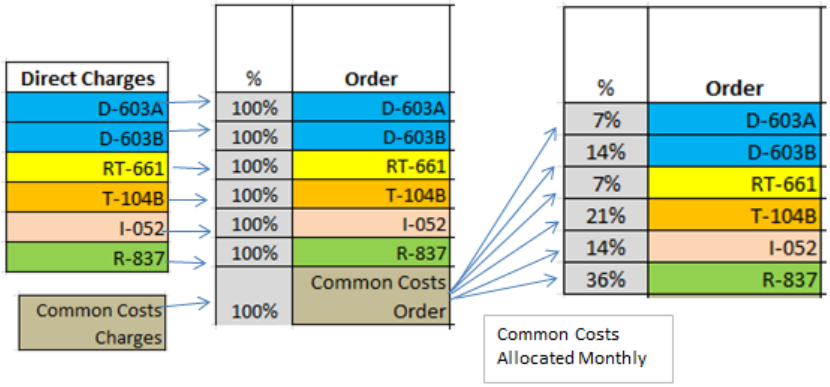
Primary Order Method PB Cost Charging Example:

(T-104B is the Primary Project)



Common Order Method PB Cost Charging Example:



B) JOURNAL ENTRIES

For COM, charges from the Common Cost order will be transferred monthly, when possible, by automated journal entry based on the pre-determined allocation percentages so that that the Common Cost Order has a zero balance when completed. If Common Cost charges are incurred prior to the automated journal entry set-up, the true-up manual journal entry process is needed prior to activating the automated process.

C) CONSTRUCTION CHANGE ORDERS

The existing RFI/PCO/COR process will be followed for individual projects. Such requests should follow the individual project impacted as much as possible. If there is a Common Cost impact, the process should follow the Common Cost order in Unifier for resolution and allocation.

RFIs and CWA change orders on PBs will be managed using Unifier. The PB Instructions and the CWA language, for contracted bundles, and design drawings will provide instructions where to direct RFIs when questions or requests arise.

CWA change orders require careful management to ensure they comply with the intent of the approved PB Plan because of the critical nature of adhering to the approved cost allocations. To the maximum extent practical,

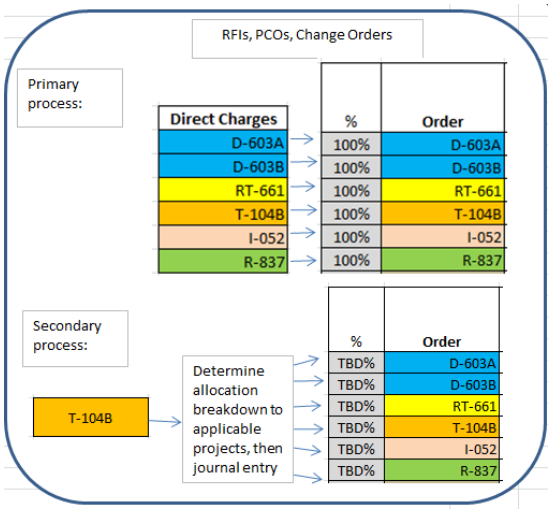
GT Project Delivery System

PROJECT BUNDLE GUIDELINES

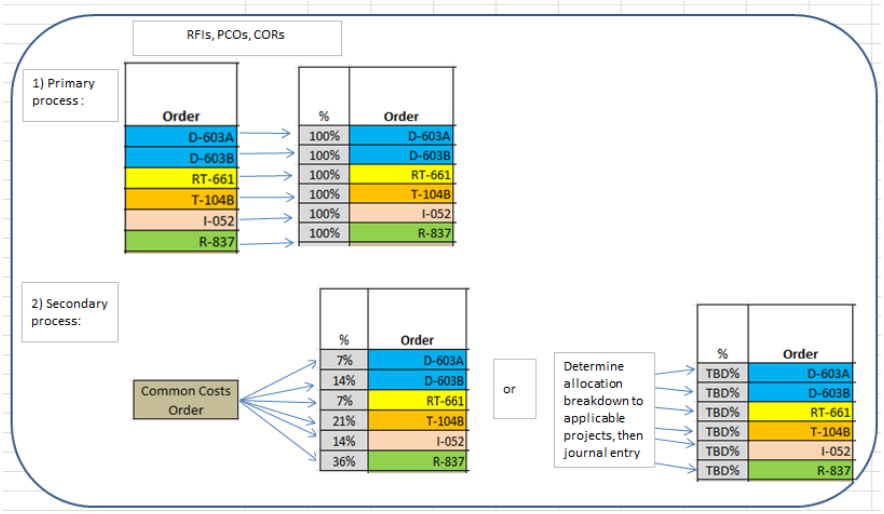
PCOs should be grouped to allow for direct charging to individual orders to minimize the need to define custom allocations for each change order. Where a CWA change order must include an allocation approach, the allocation method used must comply with the PB Plan and must give clear direction to the contractor how to collect costs, specific to the change order work, and invoice for that work in accordance with the instructions included in the CWA change order. Sourcing will group COs in SRM on a monthly basis or as needed.

Primary Order Method PB Construction Change Order Example:

(T-104B is the Primary Project)



Common Order Method PB Construction Change Order Example:



PROJECT BUNDLE GUIDELINES

D) INVOICING

The Contract Specialist will work with the Lead Project Manager/Program Lead to develop the appropriate CWA instructions for invoicing in accordance with the PB Plan. Invoices will go directly to individual orders as much as possible and Common Costs will be invoiced to the Common Cost responsible party (Lead Project Manager for Primary Order PBs, Program Lead for Common Order PBs).

XI. ORDER CLOSEOUT

A) TRUE-UP (Alliance Contracts Only)

The True-up process will be followed for the complete PB. Any over/under splits will be shared using the Common Cost order and the respective cost allocation percentages, unless otherwise agreed. If the allocation percentages change for whatever reason, the True-up over/under will be shared based on the cost allocation percentages at the time of processing.

B) CLOSING INDIVIDUAL ORDERS

Since a Common Cost order may continue to incur charges and have charges allocated or assigned, each individual order in the project bundle must remain open until common costs have been fully allocated and change orders are fully processed on every project in the bundle. For contracted jobs, this is at least until the True-up process is fully complete and reconciled. Once a Common Cost order has completed all allocations, Business Finance must be notified so that those orders can be removed from the automation template. Thereafter, individual orders in a bundle will follow standard PDS project closeout procedures, including a PB Lessons Learned, once the PB Lead PM / Program Lead provides written notification that allows the individual orders to be closed.

XII. PROJECT BUNDLE OVERSIGHT

A) PROJECT BUNDLE CHANGE MANAGEMENT

If there is a project added or deleted from the PB after a PB Plan has been accepted, a revised PB Plan must be approved to modify common cost allocations, risk and contingency adjustments and system updates. The modification to common costs allocation percentages will be effective from the date of the newly accepted PB Plan and be applied moving forward. Any previously allocated common costs will not be modified or retroactively corrected to the new percentages. The Lead Project Manager/Program Lead then must revise PB Instructions and reissue as appropriate to communicate the changes.

B) SCHEDULE MANAGEMENT

Project schedules will be prepared and maintained at the individual order level. If required by the Lead Project Manager/Program Lead, individual schedules may need to be linked to account for dependencies between work in individual orders and allow better tracking of critical paths where necessary (e.g., common clearance windows or when work under one order cannot proceed until work under a different order is completed). Linking of separate individual order schedules is not a simple task and adds a layer of complexity that requires careful cost/benefit analysis and close management to yield intended benefits and therefore must be carefully considered before proceeding.

PROJECT BUNDLE GUIDELINES

When coordinated schedules are required, a Lead PB Scheduler will be identified to coordinate bundle schedules to provide key overall schedule information to the Lead Project Manager/Program Lead to assist in achieving the intended cost efficiencies through the project bundle delivery approach.

C) RISK MANAGEMENT

The PMs for each order in the bundle are responsible to prepare and maintain separate project Risk Registers that identify, track and manage risks specific to the work associated with their order(s). Workstream PMs must inform new or update existing risks to the Lead Project Manager/Program Lead for the monitoring and management of the PB Risk Register.

D) FORECASTING

Unless otherwise required by the Lead Project Manager/Program Lead, forecasting will be done at the individual order level using the new Cash Flow Forecasting method, not at the bundle level. The Lead PM / Program Lead communicates monthly or makes available to the applicable Project Mangers the forecast and potential impact of charges or RFIs/PCOs/Change Orders that are in the Common Cost Order.

E) DOCUMENTS & RECORDS

All documents and records for individual orders will follow standard PDS processes and be stored in their respective order in ProjectWise (a PB folder will not be created in ProjectWise). Bid documents will reside in the Common Cost order Unifier environment.

		Project Bundle Method	
Document Type	Document Examples	Common Order Method	Primary Order Method
Individual project documents	PE Plan, Project Risk Register, Stand-alone JE	Respective workstream order folder	Respective workstream order folder
Project Bundle documents	PB Plan, PB QRA, Bundle Job Estimate, PB Risk Register	Native documents in the project folder of the first project listed after the Common Cost Order on the accepted PB Plan. PDF copies in other individual project folders	Native documents in Primary Project folder. PDF copies in other individual project folders

XIII. PROJECT BUNDLE GUIDELINES CHANGE PROCESS

Due to the inter-disciplinary impact of Project Bundles, proposed or actual changes to this Project Bundle Guideline document need the engagement and acceptance of the following stakeholder groups:

- Business Finance
- Capital Accounting
- Design Engineering
- Integrity Management
- Investment Planning
- Project Controls and Governance
- Project Management

PART 1: OVERVIEW

a) Best Practice: 8 **b) Status:** Complete

Company Emergency Procedures

Written company emergency procedures which describe the actions company staff will take to prevent, minimize and/or stop the uncontrolled release of methane from the gas system or storage facility 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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E performs regular maintenance on its system and has procedures in place to minimize and support the prevention of uncontrolled release of methane. In addition, PG&E's Gas Emergency Response Plan (GERP) addresses how the company responds to emergencies, including uncontrolled release of gas from the gas system or storage facility. Although PG&E relies on multiple layers of protection to prevent the uncontrolled release of natural gas, when releases do occur, PG&E is prepared to respond. Among benchmarked utilities PG&E's emergency response time performance is top decile. In 2017, PG&E's average response time was 20.4 minutes and it responded within 60 minutes 99.6% of the time. In addition to responding as quickly as possible, PG&E monitors and pushes for continual improvement in the time it takes to shut-in the gas following an unplanned release. In 2017, the shut-in the gas time for gas service-related events was 45.16 minutes, which was an improvement of 0.6 minutes over 2016 performance. For events involving gas mains, the shut-in the gas time in 2017 was 103.78 minutes which was 0.65 minutes better than 2016 performance. In 2018, the target for services is 44.03 minutes with a median time of 35 minutes, and the mains target is 101.19 minutes with a median of 87 minutes.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E plans to utilize its existing process as mentioned in question a) above as it adheres with the BP.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

The regulations that overlap with this regulation are GO 112(f) and 49 CFR 192.615. No portion of this BP is incremental to these regulations.

e) What technology is required to implement the best practice and why?

No new technology is required.

f) Will work require additional personnel and/or contract support? If so, please provide details.

No additional resources are required.

g) What changes to existing operations are required? How will those changes be implemented?

No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.

No new procedures are required.

i) Timeline for implementation (Milestones):
Compliance with this BP is complete.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
No costs are associated with this BP.

k) Identify any cost benefits from this BP, when cost estimates are known:
See question j) above.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
See question j) above.

m) Anticipated Emissions Reductions from this BP:
PG&E is currently adhering to this Best Practice, any improvement in the average gas shut in time will directly impact the emissions reduction by reducing the amount of time the leak stays open. Emissions are reported annually in the leak report for Leak Abatement OIR.

2015 Baseline Emissions affected, where known:
In 2015, emission from distribution dig-ins is 127 MMscf while emission from transmission dig-ins is 81 MMscf. The total is 208 MMscf.

n) Calculation Methodology:
Please see the response under part m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
None.

d) Other:
None.

PART 1: OVERVIEW

a) Best Practice: 9 **b) Status:** Complete

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 General Order (GO)- 112 F and succeeding revisions, and 49 CFR 192. Currently, the record retention period in GO-112 F is at least 75 years for the transmission system. 49 CFR 192.1011 requires a record retention period 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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

The Gas Operations Records & Information Management (RIM) team updated the Enterprise Records Retention Schedule with the new GO-112F retention requirements as outlined above.
Two additional Record Categories were added on 12/22/16 to comply with CPUC GO-112F, to reflect the new requirements regarding Gas Transmission:

EDC0120 – Transmission Pipeline Repair
EDC0140 – Transmission Patrol, Surveys, Inspections and Tests

In addition to the changes made to the schedule the Gas Operations RIM team also mapped those changes to the electronic systems managing offsite storage documents to ensure compliance with these new retention requirements.

See supplemental section below for additional details on the above-mentioned documents.

b) Alternative Proposal to BP or exemption? None.

c) Proposed Plan:

The plan referenced above in question a) was completed and executed as of 12/31/16.
Actions taken to comply with this BP were: (1) Research the GO-112 F requirements and align those requirements with the records retention schedule and related systems of record; (2) Publish a new revised records retention schedule; and (3) Communicate those changes to the impacted work groups;

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

49 CFR 192 – requires a record retention period of at least 10 years after the trigger event. GO-112 F extends those requirements to 75 years or more. No portion of this BP is incremental.

e) What technology is required to implement the best practice and why?

No technology is required.

f) Will work require additional personnel and/or contract support? If so, please provide details.

No additional resources are needed as this work is complete.

g) What changes to existing operations are required? How will those changes be implemented?
No changes to the existing operation are necessary.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
GOV-7101 S and the Records Retention Schedule were modified to reflect the necessary changes made. See the supplemental section below for additional details.

i) Timeline for implementation (Milestones):
This BP is complete.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
No costs are associated with this BP.

k) Identify any cost benefits from this BP, when cost estimates are known:
See question j) above.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
See question j) above.

m) Anticipated Emissions Reductions from this BP:
No anticipated emissions reductions are anticipated for this BP.

2015 Baseline Emissions affected, where known:
See PG&E's response to question m) above.

n) Calculation Methodology:
See PG&E's response to question m) above.

o) Additional Comments:
None.

p) Overlap with Safety: Guidance documents that are a part of the compliance plan, identify, when relevant, safety items associated with following the guidance. Other documents used in this compliance plan like policies, standards or manuals, may also identify and address safety issues.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
See attached for updated schedule and procedures (BP09_ATCH01).

c) Research or Studies:
None.

d) Other: None.

Enterprise Records and Information Management Standard
All LOB Enterprise Records Retention Schedule

Compliance & Ethics - Record Categories

Record Category ID: FIN1600 | Record Category Name: Compliance & Ethics Records - Administration

Trigger Event: When superseded

Retention Period: ACT+ 5 years

Description: Records related to the administration and management of PG&E's company ethics policies and activities.

Examples:

- Code of Conduct
- Code of Conduct Training
- Compliance & Ethics Annual Training Materials
- Compliance and Ethics Annual Training Materials
- Helpline

Record Category ID: FIN1650 | Record Category Name: Compliance & Ethics Records - Regulatory Compliance

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to reporting on PG&E's company ethics policies and activities to external 3rd parties.

Examples:

- CPUC Affiliate Rules
- FERC Standards of Conduct
- Responses to Requests from External, Regulatory 3rd Parties

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).
Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: GOV0100 | Record Category Name: Audit and CAP Records

Trigger Event: Completion of follow-up actions resulting from audit findings

Retention Period: ACT+ 10 years

Description: Records related to internal and external audits of PG&E's corporate operations, including responses to internal and external audit notifications, and authorized issues entered in CAP.

Examples:

- Audit Investigation Reports
- Audit Notices and Notices of Violations
- Audit Reports and Responses to External Parties (e.g., FERC, NERC, CPUC, SOX)
- Audit Satisfaction Survey Results
- Auditor Evaluations
- Business Results Team Documents Associated to Audits
- Control Room Management Audit Reports
- Corrective Action Program (CAP) Issues

Record Category ID: GOV0210 | Record Category Name: Audit Records - Planning & Administration - Electric T&D

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to the management and administration of PG&E's electric T&D audits, including both internal and external PG&E audits.The 3 year requirement cited by Orrick is applies to OTC derivatives dealers, but it being used by PG&E as a best practice.

Examples:

- Audit Checklists (completed)
- Audit Plan
- Audit Schedule(s)

BP09_ATCH01-2

Record Category ID: GOV0215 | Record Category Name: Audit Records - Planning & Administration - Energy Procurement

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to the management and administration of PG&E's energy procurement audits, including both internal and external PG&E audits.The 3 year requirement cited by Orrick is applies to OTC derivatives dealers, but it being used by PG&E as a best practice.

Examples:

- Audit Checklists (completed)
- Audit Plan
- Audit Schedule(s)

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: GOV0220 | Record Category Name: Audit Records - Planning & Administration - Gas

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to the management and administration of PG&E's gas operations audits, including both internal and external PG&E audits. The 3 year requirement cited by Orrick is applies to OTC derivatives dealers, but it being used by PG&E as a best practice.

Examples:

Audit Checklists (completed)

Audit Plan

Audit Schedule(s)

Record Category ID: GOV0225 | Record Category Name: Audit Records - Planning & Administration - Nuclear

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to the management and administration of PG&E's nuclear operations audits, including both internal and external PG&E audits. The 3 year requirement cited by Orrick is applies to OTC derivatives dealers, but it being used by PG&E as a best practice.

Examples:

Audit Checklists (completed)

Audit Plan

Audit Schedule(s)

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Record Category ID: GOV0230 | Record Category Name: Audit Records - Planning & Administration - Power Generation

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to the management and administration of PG&E's power generation-related audits, including both internal and external PG&E audits.The 3 year requirement cited by Orrick is applies to OTC derivatives dealers, but it being used by PG&E as a best practice.

Examples:

Audit Checklists (completed)

Audit Plan

Audit Schedule(s)

Record Category ID: GOV0300 | Record Category Name: Contract & Agreement Records - Corporate

Trigger Event: End of contract, or on expiration of all obligations, whichever is later

Retention Period: ACT+ 10 years

Description: Fully executed contracts or agreements, and the records related to their creation, between PG&E and its suppliers, customers or other parties that are related to the acquisition of corporate (non-utility) supplies and services. Does not include collective bargaining agreements.

Examples:

Agreements, Amendments and Contracts

Change Orders

Compliance Mailings (Corporate Secretary)

Contract Work Authorizations

Letters of Intent

Non-Disclosure Agreements (NDA)

Statements of Work

Work & Task Orders

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: GOV0310 | Record Category Name: Contract & Agreement Records - Electric T&D

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Fully executed contracts or agreements, and the records related to their creation, between PG&E and its suppliers, customers or other parties that are related to the acquisition of corporate (non-utility) supplies and services. Does not include collective bargaining agreements.

Examples:

- Agreements, Amendments and Contracts
- Applications for Service & Supporting Docs
- Change Orders
- Contract Work Authorizations
- Letters of Intent
- Statements of Work
- Work & Task Orders specific to Contracts and Contractors

Record Category ID: GOV0320 | Record Category Name: Contract & Agreement Records - Gas

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Records related to documenting mutual legal obligations between PG&E and its suppliers, customers or other parties that are related to the acquisition of gas operations supplies and services. Does not include collective bargaining agreements.

Examples:

- Agreements, Amendments and Contracts
- Change Orders
- Contract Work Authorizations
- Letters of Intent
- Statements of Work
- Work & Task Orders

Record Category ID: GOV0330 | Record Category Name: Contract & Agreement Records - Energy Procurement

Trigger Event: End of contract, or on expiration of all obligations, whichever is later

Retention Period: ACT+ 10 years

Description: Fully executed contracts or agreements, and the records related to their creation, between PG&E and its suppliers, customers or other parties that are related to the acquisition of corporate (non-utility) supplies and services. Does not include collective bargaining agreements.

Examples:

- Contract Support Documents (market valuations, viability assessments)
- Master Agreements
- Settlement Contracts
- Settlement Invoice Packages
- Settlement Protocols
- Short Term Contracts
- Term Contracts

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: GOV0340 | Record Category Name: Contract & Agreement Records - Nuclear

Trigger Event: Permanent cessation of operations/activities at licensed site

Retention Period: ACT+ 60 years

Description: Fully executed contracts or agreements, and the records related to their creation, between PG&E and its suppliers, customers or other parties that are related to the acquisition of corporate (non-utility) supplies and services. Does not include collective bargaining agreements.

Examples:

- Agreements and Amendments
- Change Orders
- Contract Work Authorizations
- Contracts & Subcontracts
- Letters of Intent
- Master Service Agreements
- Modifications
- New Business Agreements
- Statements of Work
- Technical Specifications (attached to contract)
- Work & Task Orders

Record Category ID: GOV0350 | Record Category Name: Contract & Agreement Records - Power Generation

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Fully executed contracts or agreements, and the records related to their creation, between PG&E and its suppliers, customers or other parties that are related to the acquisition of corporate (non-utility) supplies and services. Does not include collective bargaining agreements.

Examples:

- Agreements and Amendments
- Change Orders
- Contract Work Authorizations
- Contracts & Subcontracts
- Letters of Intent
- Master Service Agreements
- Modifications
- New Business Agreements
- Statements of Work
- Technical Specifications (attached to contract)
- Work & Task Orders

Record Category ID: GOV0400 | Record Category Name: Corporate Governance Records

Trigger Event: End of calendar year

Retention Period: Life of Company

Description: Filings and authorizations by regulatory agencies: applications, registrations or other documents filed by the company with the Federal or state regulatory agency for authorization or validation of transactions; the opinion, order or other document evidencing the agency's actions thereon; and any report of consummation or compliance, with respect to organization or conduct or business of the company and changes therein, including merger.

Examples:

- 20 Largest Purchasers - Report to FERC
- Affidavits Lost Certificate Replacements ("A" Files)
- Affidavits of Mailing (Proxy Mailings)
- Annual Reports
- Articles of Incorporation
- Business Registration Renewals
- Bylaws
- Certificate of Registration for Trademarks
- Certificates of Incumbency
- Certificates of Inspector of Elections
- Common Stock Issue Reports
- Common Stock Offerings
- Compliance Mailings (To Financing & Other Entities)
- Contacts
- Correspondence
- Credit Agreements / Closing Documents
- Delegations of Authority
- Director & Officer Questions
- Dividend Payment Information
- Dividend Reinvestment Plan Activity
- Federal Reserve Bank of New York Surveys of Foreign Investment
- FERC 561 Report
- Final Management Ballots - Annual Meeting (Proxy)
- Form 1096
- Form 10-K & Annual Report
- Form 10-Q
- Form 8-K
- Forms 1099-Misc
- Gas Service Agreements
- Initial Statement of Beneficial Ownership of Securities (Form 3)
- Meeting Minutes & Materials
- Name Changes
- Notice of Annual Meetings & Proxy Statements
- NYSE Listing Applications
- Oaths of Inspector of Elections
- PG&E Corporation 2006 Long Term Incentive Program
- PG&E Corporation Director Fees & Retainers
- Powers of Attorney
- Proxy Record Date - List of Share Holders
- Proxy Tabulation Reports
- Resignations
- Securities and Exchange Commission Form U-3A-2
- Shareholder Correspondence
- Statement of Changes in Beneficial Ownership (Form 4)
- Stock Certificates "Lost and Found"
- Stock Issuance Instructions
- Stock Quarterly Reconciliation Report
- Timesheets (Payroll Records)
- Transfer Folios (1994 - June 1999)
- Transfer Journals (Stock & Debenture)

Examples:

- Enterprise Risk Management Documents Management committee meeting materials

Record Category ID: GOV0600 | Record Category Name: Insurance Records - Policies, Claims & Certificates

Trigger Event: Expired

Retention Period: Life of company

Description: Records related to PG&E's insurance policies, claims and certificates.

Examples:

- Certificates of Insurance
- Insurance Claims
- Insurance Plans (all types of insurance)
- Insurance Policies (all types of insurance)

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: GOV0700 | Record Category Name: Intellectual Property Records

Trigger Event: End of calendar year

Retention Period: Life of Company

Description: Records related to establishing, documenting and defending PG&E's ownership and rights of its brand, property and assets (both tangible and intangible).

Examples:

- Copyrights
- Enforcement Actions
- Intellectual Property Agreements
- Internal Fraud and Espionage Information
- Patent Registrations
- Permissions and Approvals for Use of Material Trademarks

Record Category ID: GOV0800 | Record Category Name: Litigation and Claims Records

Trigger Event: Final resolution or date closed

Retention Period: ACT+ 10 years

Description: Records related to managing and resolving litigation, claims or disputes, including pleadings, exhibits and trial proceedings. For litigation involving minors, see Litigation Records - Minors.

Examples:

- Attorney Working Files
- Case Management Information
- Claim Files
- Final Settlement Agreements
- Litigation Files
- Subpoena Files

Record Category ID: GOV0810 | Record Category Name: Litigation Records - Minors

Trigger Event: Age of maturity

Retention Period: ACT+ 10 years

Description: Records related to managing and resolving litigation, claims or disputes involving minors.

Examples:

- Attorney Working Files
- Case management Information
- Claim Files
- Final Settlement Agreements
- Litigation Files
- Subpoena Files

Record Category ID: GOV0850 | Record Category Name: Litigation Records - Intellectual Property Research

Trigger Event: End of calendar year

Retention Period: Life of Company

Description: Records related to the documentation of legal intellectual property, research, advice and opinions associated to major litigation, claim or dispute cases.

Examples:

- Legal Advice/Opinions
- Research Files

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: GOV1400 | Record Category Name: Training Records - Minimum Continuing Legal Education (MCLE) Training & Certifica

Trigger Event: Date of reporting MCLE compliance **Retention Period:** ACT+ 1 year

Description: Records related to planning, developing, maintaining and completing MCLE-related training and self-certifications.

Examples: MCLE Training & Certification Records

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).
Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Customer Care - Record Categories

Record Category ID: CUS0100 | Record Category Name: Customer Billing & Account Management Records

Trigger Event: End of customer relationship **Retention Period:** ACT+ 10 years

Description: Records related to the set up, approval, and ongoing management of customer accounts, including customer/account statements, service applications, account/service authorizations, and daily management of customer accounts.

Examples:

- Applications and Other Information Related to the Establishment of New Business/Customer Account
- Authorization Requests and Releases
- Customer Communications and Other Correspondence (e.g., letters related to account, "can't access" notices/letters)
- Customer Orders
- Letters of Credit
- Reviews, Refunds and Deficiencies
- Usage Data (Customer)

Record Category ID: CUS0110 | Record Category Name: Customer Billing Administration Records

Trigger Event: End of current calendar year **Retention Period:** ACT+ 2 years

Description: Records related to the establishment, administration and reporting of customer billing, including the establishment of associated fees and rates.

Examples:

- Billed Revenue Data (responses to ad hoc requests for billing data)
- Utility User Tax Information (exemption discrepancies, payments)

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Record Category ID: CUS0120 | Record Category Name: Customer Payment Processing Records

Trigger Event: End of calendar year **Retention Period:** ACT+ 10 years

Description: Records related to the establishment, administration and processing of customer payments.

Examples:

- Bill Print, Mail Reports
- Customer Inquiry Assistance Records
- Payment Adjustments
- Payment Processing Reports

Record Category ID: CUS0200 | Record Category Name: Customer Engagement Records

Trigger Event: End of current calendar year **Retention Period:** ACT+10 years

Description: Records related to the planning and management of customer interactions, including the management of customer complaints.

Examples:

- Complaints and Associated Information
- Customer Relations Documents
- Outcomes Reports

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: CUS0300 | Record Category Name: Energy Solutions Records

Trigger Event: End of calendar year, or end of contract, whichever is later

Retention Period: ACT+ 6 years

Description: Records related to providing programs and assisting customers in making energy efficient upgrades that reduce energy consumption, save money and benefit the environment. Includes records related to demand response, distributed generation, solar, energy saving assistance and demand side management programs.

Examples:

- Channel Engagement Documents
- Core Products Documents
- Demand Response Documents
- Distributed Generation Documents
- Emerging Information Products Documents
- Energy Savings Assistance Documents
- New Revenue Development Documents
- Solar Documents

Record Category ID: CUS0400 | Record Category Name: Meter Records - Equipment

Trigger Event: Life of meter (when sold, dismantled or destroyed)

Retention Period: ACT+ 5 years

Description: Records related to the maintenance and upkeep of individual meters and meter functionality.

Examples:

- Field Workers Statistical Reports
- Maintenance Records
- Meter Disposition Information
- Meter Location Information
- Meter Maintenance Orders
- Meter Problem Reports
- Meter Profile Information
- Status Reports
- Tamper Alerts
- Test Records
- Unauthorized Access Notices

Record Category ID: CUS0410 | Record Category Name: Meter Records - Billing Exceptions

Trigger Event: End of calendar year

Retention Period: ACT+ 7 years

Description: Records related to the ongoing tracking and reporting of meter billing exceptions.

Examples:

- Meter Change Requests and Change Reports
- Meter Dial Change Reports
- Meter Removal Reports
- Upload Error Reports

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: CUS0500 | Record Category Name: Service Center Operations

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to planning, developing and implementing customer service center operations to respond to, service and support PG&E's customers, including customer contact center.

Examples:

- Customer Call Center Documents
- Customer Call Center Information
- Customer Call Center Recordings
- Dispatch Logs
- Service Requests & Schedules

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: EDC0100 | Record Category Name: Engineering, Design & Construction Records - Electric T&D

Trigger Event: Life of Asset **Retention Period:** ACT+ 10 years

Description: Records related to all activities associated with design and construction of electric T&D assets.

Examples:

- Advance Authorizations (AA)
- Arrangement of Splice in Manhole
- Arrangement of Terminations
- As-Built Markups
- As-Built Records of Facilities (including Maps)
- Asset Data Sheets
- Bill of Materials & Drawing List
- Bonding & Grounding Schematic Drawing
- Bonding and Grounding Schematic Drawing (Originally Conduit Schedule)
- Bus Fault Force Calculations
- Business Cases
- Cable Protector Drawings
- Cable Racking Details (Originally Cable Racking)
- Capital Emergency Management (CEM)/Surplus/Stock
- Circuit Map Change Sheets (CMCS)
- Clipping Offsets
- Conduit Arrangement at Cable Termination (Originally Conduit Arrangement)
- DART / SAP Asset Register
- Design Criteria
- Design Standard Drawings (Engineering Documents)
- Drawing Schedules (Circuit, Conduit, etc.)
- DTS Fiber Optic Diagram (Originally Conduit Diagram)
- Electrical Drawings (Arrangement & Schematics)
- Emergency Bank Loss Studies
- Equipment Approval Drawings
- Equipment History Cards
- Equipment Nameplate Drawings
- Equipment Outline Drawings
- Estimator Sketch (Wood Pole Work)
- Feed-in Drawings
- Grading Plan
- Ground Grid Calculations
- Grounding Arrangements (Cell sites)
- Hardware Drawings
- Job Estimates
- Joint Pole Calculations
- Manhole Drawings
- Map Corrections
- Material Problem Report (Form 61-1100)
- Mobile Equipment Data
- Overhead Ground/Shield Wire Drawings
- Permits
- Plan & Profile Maps
- Pole Loading Calculations (See S0027)
- Pole Loading Calculations (see TD-9999B-001)
- Pothead & Lightning Arrester Drawings
- Preliminary/Advance Job Records
- Project Administration Documents
- Project Job Files
- Project Scope and Design Documents
- Project/Program Authorizations
- Property Maps
- Pull-Out Drawing
- Riser Pipe Drawing
- Standards Civil/Structural Calculations
- Structure Check Sheets
- Substation Bus Structure
- Substation Equipment Manufacturer's Drawings
- Tower Structure Drawing
- Transmission Structure Drawing
- Underground (UG) Transmission Maps at Substations
- Underground (UG) Transmission Route Maps
- Valmont Structural Fabrication Drawings

Record Category ID: EDC0130 | Record Category Name: Engineering, Design & Construction Records - Power Generation

Trigger Event: Life of Asset **Retention Period:** ACT+ 10 years

Description: Records related to all activities associated with design and construction of power generation-related assets, original construction and subsequent modifications and design changes, including hydro-electric, fossil, photovoltaic, and fuel cell generation assets

Examples:

- Advance Authorizations (AA)
- As-Built Markups
- As-Built Records of Facilities (including Maps)
- Bill of Materials & Drawing List
- Business Cases
- Design Criteria
- Design Standard Drawings (Engineering Documents)
- Drawing Schedules (Circuit, Conduit, etc.)
- Equipment Approval Drawings
- Equipment History Cards
- Equipment Outline Drawings
- Job Estimates
- Project Administration Documents
- Project Job Files
- Project Scope Documents
- Project/Program Authorizations
- Site and/or Job Specific Work Procedures

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Electric Operations - Record Categories

Record Category ID: EDC0200 | Record Category Name: Geographic Information System (GIS) Records - Electric T&D

Trigger Event: Superseded

Retention Period: Superseded

Description: Records and data related to current geographical and asset information for all electric T&D operating regions as contained in PG&E's GIS.

Examples:

LOC (Class Location)

Standardized Structure Layer

Record Category ID: EDC0600 | Record Category Name: Locate and Mark Records - 811 - Electric T&D

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to the 811 Public Service Center responses to public requests for locations of PG&E electric T&D lines.

Examples:

811 Communications

811 Field Reports

811 Notifications of Findings

811 Ticket Information

Record Category ID: EDC0700 | Record Category Name: Locate and Mark Records for Assets - Electric T&D

Trigger Event: Life of Asset

Retention Period: ACT+ 6 years

Description: Records related to finding, marking and mapping the location of electric T&D assets.

Examples:

Comparison Reports

Field Reports

Locating Communications, including 811 Reports Requested by PG&E Staff

Notifications of Findings

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: EDC1000 | Record Category Name: Policies, Procedures & Standards - Operational & Technical - Electric T&D

Trigger Event: Superseded

Retention Period: Life of Company

Description: Records related to planning and developing policies, procedures and standards related to electric T&D assets and operations.

Examples:

- 500kV Manual
- 7.9 RFL 6745 TT Maintenance Procedure
- 9.10 RFL 9745 Audio Maintenance Procedure
- 9.11 GE N60 Maintenance Procedure
- All Design Specifications
- All Engineering and Design Calculations
- All Engineering and Design Models
- All Engineering Manuals
- All Maintenance Specifications
- All Measurement and Control Specifications
- All Routine Maintenance Equipment Instruction
- All Routine Maintenance Equipment Procedures
- All Routine Maintenance Equipment Test Reports
- All Technical Specifications
- Critical Infrastructure Protection (CIP) 2 CCA List Electronic SCADA
- Critical Infrastructure Protection (CIP) 2 CCA List Substations
- Critical Infrastructure Protection (CIP) 3 Information Security Doc
- Critical Infrastructure Protection (CIP) 7 Configuration & Change Management Docs
- Design Criteria
- Design Standard Drawings (Engineering Documents)
- Electric Emergency Plan for CPUC
- Engineering or Benchmarking Studies
- Equipment Approval Drawings
- Equipment Nameplate Drawings
- Equipment Outline Drawings
- Equipment Specifications
- Event Report to DOE (Department of Energy)
- General Order 95 Correspondence
- Ground Grid Calculations
- Historical Equipment Files
- Industry Standards, including current and vintage
- Jobsite Hazard Analysis Forms
- Mobile Equipment Data
- Operator Training Tracking Program (TRACCESS)
- Project Administration Documents
- Protective Equipment Standard Test Procedures (PEST) Manual
- Quarterly Outage Plan for California Independent Systems Operators (CAISO)
- Remedial Action Schemes (RAS) Documents
- Restoration Plan for Small Transmission Outages
- Standards & New Procedure Equipment Specifications
- Superseded Bulletins
- Transmission and Distribution (T&D) Bulletins and Manuals
- Transmission Line and Substation Design Standards
- Transmission System Operations (TSO) Application for Work (AFW)
- Transmission System Operations (TSO) Voice Recordings

Record Category ID: EDC1030 | Record Category Name: Policies, Procedures & Standards - Operational & Technical - Power Generation

Trigger Event: Superseded

Retention Period: Life of Company

Description: Records related to planning and developing policies, procedures and standards related to power generation assets and operations, including hydroelectric, fossil, photovoltaic, and fuel cell generation assets

Examples:

- All Design Specifications
- All Engineering and Design Calculations
- All Engineering and Design Models
- All Engineering Manuals
- All Maintenance Specifications
- All Measurement and Control Specifications
- All Technical Specifications

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Electric Operations - Record Categories

Record Category ID: EDC1110 | Record Category Name: Quality Control Records - Electric T&D

Trigger Event: Life of Asset **Retention Period:** ACT+ 10 years

Description: Records related to the monitoring and tracking of PG&E's quality control and improvement activities for electric T&D.

Examples:

- QC Assessment Documents
- QC Corrective Action Results
- QC Plans and Procedures (all electric operations)
- QC Reports and Reviews

Record Category ID: EDC1130 | Record Category Name: Quality Control Records - Power Generation

Trigger Event: Life of Asset **Retention Period:** ACT+ 10 years

Description: Records related to the planning, development, implementation and monitoring and tracking of PG&E's quality assurance and quality control activities for power generation activities, including hydroelectric, fossil, photovoltaic, and fuel cell generation assets

Examples:

- Certified Test Reports
- Corrective Action Reports
- Nonconformance Reports
- Qualification Reports
- Traceability Records

Record Category ID: FIN0300 | Record Category Name: Security Records - Physical Security

Trigger Event: End of calendar year **Retention Period:** ACT+ 1 year

Description: Records related to providing daily security services for all internal operations, ensuring the physical safety and security of people and PG&E property.

Examples:

- Investigation Letters and Reports
- Loss and Damage Reports
- Security Logs (including outage logs)
- Security Surveys

Record Category ID: FIN0305 | Record Category Name: Security Records - Physical Security - Access

Trigger Event: End of month **Retention Period:** ACT+ 90 days

Description: Records related to documenting and monitoring physical access to PG&E operating locations.

Examples:

- Access Card Administration
- Access Logs and Requests

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: FIN0310 | Record Category Name: Security Records - Vulnerability (Non-Nuclear)

Trigger Event: End of investigation or end of calendar year, whichever is later

Retention Period: ACT+ 3 years

Description: Records related to the investigation of threats, thefts, and sabotage (actual or suspected) relating to utility operations.

Examples:

- Documentation of all Inspections
- Documentation of all Tests, Inspections, and Maintenance Performed on Communications Equipment
- Documentation of all Tests, Inspections, and Maintenance Performed on Intrusion Alarms
- Documentation of all Tests, Inspections, and Maintenance Performed on other Security Related Equipment
- Documentation of all Tests, Inspections, and Maintenance Performed on Physical Barriers
- Documentation of all Vulnerability Security Tours
- Investigation records and reports
- Patrol Logs
- Records Relating to the Protection of Safety-related Systems
- Vital Area Access Lists
- Vulnerability Assessments

Record Category ID: FIN0320 | Record Category Name: Security Records - Vulnerability (Nuclear)

Trigger Event: End of investigation or end of calendar year, whichever is later

Retention Period: ACT+ 3 years

Description: Records related to the investigation of threats, thefts, and sabotage (actual or suspected) relating to nuclear activities, including special nuclear material, high-level radioactive wastes, nuclear facilities, and other radioactive materials and activities regulated by the NRC. If used in support of decommissioning operations, see Decommissioning Records - Nuclear.

Examples:

- Documentation of all Inspections
- Documentation of all Tests, Inspections, and Maintenance Performed on Communications Equipment
- Documentation of all Tests, Inspections, and Maintenance Performed on Intrusion Alarms
- Documentation of all Tests, Inspections, and Maintenance Performed on other Security Related Equipment
- Documentation of all Tests, Inspections, and Maintenance Performed on Physical Barriers
- Documentation of all Vulnerability Security Tours
- Investigation records and reports
- Patrol Logs
- Records Relating to the Protection of Safety-related Systems
- Vital Area Access Lists
- Vulnerability Assessments

Record Category ID: FIN0330 | Record Category Name: Investigations Records - Background Checks

Trigger Event: Completion of assessment or background check

Retention Period: ACT+ 7 years

Description: Records related to the administration and management of personnel risk assessments and background checks conducted in support of PG&E's utility operations.

Examples:

- Background Checks
- Personnel Risk Assessments

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: FIN0340 | Record Category Name: Investigations Records - Compliance

Trigger Event: End of investigation or assessment **Retention Period:** ACT+ 10 years

Description: Records related to the planning, management and operation of the company's compliance investigation and assessment activities conducted in support of PG&E's utility operations. Does not include code of conduct, criminal or quality assurance investigations conducted as part of activities covered elsewhere in this schedule.

Examples:

Investigation Case Files and Supporting Information

Record Category ID: FIN1200 | Record Category Name: Appraisals & Valuations - Plant - Energy Procurement

Trigger Event: Completion of transaction **Retention Period:** ACT+ 50 years

Description: Records related to appraisals and valuations made by PG&E of its plant properties or investments or of the properties or investments of any associated companies.

Examples:

Appraisals

Planning Strategies

Valuations

Record Category ID: FIN1210 | Record Category Name: Appraisals & Valuations - Non-Plant - Power Generation

Trigger Event: Completion of transaction **Retention Period:** ACT+ 10 years

Description: Records related to appraisals and valuations made by PG&E of its non-plant properties or investments or of the properties or investments of any associated companies.

Examples:

Appraisals

Planning Strategies

Valuations

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Electric Operations - Record Categories

Record Category ID: GOV1300 | Record Category Name: Emergency Preparedness & Response

Trigger Event: End of calendar year

Retention Period: ACT+ 7 years

Description: Records related to the planning, monitoring, tracking and response to risks associated to PG&E's corporate (non-utility) operations. Does not include financial risks - see Market and Credit Risk Management Records.

Examples:

- After Action Reports (AARs)
- Baseline Assessment Plans
- Business Continuity Guidance Documents
- Business Continuity Plans (BCPs)
- Business Impact Analysis
- Drill and Exercise Effectiveness Metrics
- Emergency Communications Plans
- Emergency Plans
- Exercise Documents & Library
- First Responder Workshop Documents (Metric, Workshop Rosters, Sign In Sheets, Event Reports)
- Incident Action Plans (IAPs)

Record Category ID: OPS0050 | Record Category Name: Incident Reporting - Electric T&D

Trigger Event: End of calendar year

Retention Period: Life of Company

Description: Records related to the requirement that PG&E report and document significant events with external parties, depending upon the type of reportable event, and/or whether PG&E operates or owns an asset. External parties may include the Department of Energy (DOE), the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC), the California Independent System Operator Corporation (CAISO) and the California Public Utility Commission (CPUC).

Examples:

- Accident Notice and Written reports
- California Public Utility Commission (CPUC) Audit Notice of Violation
- Control Center Performance Evaluation
- Electric Incident Reports
- EOC Action Plan and Incident Action Plans (IAPs)
- Federal Reporting Documents for NERC, WECC and CAISO
- ICS 211 Check In / Out Log (Sign In / Out Sheets)
- ICS 214 Unit Logs
- Incident After Action Reports (AARs), Corrective Action Plans (CAPs), Hotwash
- Incident Testimony
- Incident Videos
- Incident Videos - News Coverage
- Mutual Assistance
- Other Incident Documentation - Demobilization plan
- Other Incident Documentation - Maps
- Other Incident Documentation - Other ICS forms
- Other Incident Documentation - Photos
- Other Incident Documentation - Resource Reports
- Other Incident Documentation - Situation Unit Reports
- Responses to Data Requests from CPUC and Other External Agencies/Organizations

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: OPS0060 | Record Category Name: Inspection Records - Electric Distribution Facilities - Intrusive

Trigger Event: Life of Asset **Retention Period:** ACT+ 1 year

Description: Records related to intrusive inspections of electric distribution assets.

Examples:

- Auto Transfer Switch Inspection Records
- Bay Area Rapid Transit (BART) Cable Inspection
- Bird Incident Reports
- Electric Compliance (EC) Electric Preventive Correction Maintenance (EPCM) Notifications
- Electric Distribution (ED) Notification
- Electric Distribution Maintenance (EDM) Special Inspections- Transfer Ground Rocker Arm Main/Line (TGRAM/TGRAL)
- Infrared Inspection Logs & Maps
- Inspection Logs and Maps- Overhead (OH)
- Inspection Logs and Maps- Underground (UG)
- Intrusive Inspection Reports
- Intrusive inspection surveys
- Local Compliance Special Inspections
- Manhole (MH)/Vault Inspection Form

Record Category ID: OPS0065 | Record Category Name: Inspection Records - Electric Distribution Facilities - Patrol & Detailed

Trigger Event: End of calendar year **Retention Period:** ACT+ 10 years

Description: Records related to patrol and detailed inspections of electric distribution assets.

Examples:

- Detailed Inspection Reports
- Detailed Inspection Surveys
- Patrol Inspection Reports
- Patrol Inspection Surveys
- Patrol Logs & Maps - Overhead
- Patrol Logs & Maps - Underground
- Pole Test Data Sheets - Electric Compliance (EC) Notification
- Stub Treatment (ST) Notification

Record Category ID: OPS0066 | Record Category Name: Inspection Records - Electric Transmission Facilities

Trigger Event: End of calendar year **Retention Period:** ACT+ 10 years

Description: Records related to inspections of electric transmission facilities.

Examples:

- Compliance (EC) notification
- Inspection Reports
- Inspection Surveys
- Logs and Maps
- Test Data Sheets

Record Category ID: OPS0080 | Record Category Name: Inspection Records - Power Generation

Trigger Event: Life of Asset **Retention Period:** ACT+ 10 years

Description: Records related to inspections of power generation assets completed by PG&E, contractors, and Agencies.

Examples:

- Detailed Inspection Reports
- Detailed Inspection Surveys

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: OPS0100 | Record Category Name: Maintenance Records - Electric T&D

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to monitoring and recording of daily operations including but not limited to logs and reports

Examples:

- 3rd Party Non-Utility Forms
- 3rd Party to PG&E Maintenance Forms
- 3rd Party to Utility Maintenance Forms
- Air Switch Maintenance Form
- Bank Capability Sheet
- CE Notifications
- Circuit Breaker Relay Readings
- Circuit Breaker Relay Settings
- Circuit Capability Sheet
- CYME Runs
- Delta X (diagnostic test results)
- Disposal & Erasure Verification Records
- Distribution Fabrication Records
- Distribution Incident Report
- Distribution Misc Component Fabrication Records
- Distribution Network Transformer Maintenance Records
- Electric Compliance (EC) Notifications
- Electric Equipment Repair
- Equipment Calibration - Local Meters
- Equipment Calibration - Test Floor
- Equipment Calibrations and Test Records
- Equipment Installation & Maintenance Records
- Form TD-1957P-01-F01 "Component Testing Information Sheet"
- GO 165 Work Verification Documents
- Interrupter Settings
- Line Capacitor Settings
- Line Regulator Settings
- Load Checks
- Load Data (Circle Charts)
- Load Growth Projections
- LTC/Station Reg Settings
- Maintenance Records
- Mapping Discrepancy Forms
- Migratory Bird RETRO FIT EC Construction Completion Records
- Minor Work Logs Street Lights
- Network Protector Maintenance Records
- Oil Test Results
- Operating Logs
- Recloser Settings
- SCADAmate Switch Settings (EXISTING)
- SCADAmate Switch Settings (NEW)
- Shop Electric Equipment Repairs
- Station Inspections and Maintenance Reports
- Street Light Case Documents
- Street Light Replacement Records
- Substation / Transmission Misc Component Fabrication Records
- Substation Meter Readings - Half Hour Sheets
- Substation Meter Readings - Instrumentation Recordings
- Substation Meter Readings - Load Curves
- Substation Meter Readings - Load Reports
- Substation Meter Readings - Monthly Substation Load Reads
- Substation Misc Welding Repair Records
- T-Line Misc equipment Repair Records
- Work Verification
- WPS2321-01 Attachment 4, "Adjacent Pole Determination Form"

Record Category ID: OPS0130 | Record Category Name: Maintenance Records - Power Generation

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Records related to operations, maintenance, monitoring or condition assessment activities associated with power generation-related facilities, sites, equipment, structures, systems and components, including hydroelectric, fossil, photovoltaic, and fuel cell generation assets, that provide or assist the provision of utility service to residential, commercial or industrial customers.

Examples:

- Calibration Reports
- Contamination Surveys
- Failure Analysis Reports
- Gauge Reading Records
- Generation and Output Logs
- Operating and Maintenance Reports
- Operations Plans and Reports
- Power History

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Electric Operations - Record Categories

Record Category ID: OPS0140 | Record Category Name: Electric Transmission Protection Systems Inspections

Trigger Event: End of calendar year

Retention Period: ACT+24 years

Description: Inspections conducted on the installation and testing of electric transmission protection systems.

Examples:

Protection Reviews

Substation Test Reports

System Protection Documents

Record Category ID: OPS0200 | Record Category Name: Outage Records - Electric T&D

Trigger Event: End of calendar year

Retention Period: ACT+ 10 years

Description: Records related to identifying, managing, restoring and reporting on electric T&D supply outages for residential, commercial or industrial customers.

Examples:

500kV Operating Guideline Manual

Daily 500 kv Report on Equipment Out of Service

Daily Report to CASIO on Todays Outage Default Voltage Schedule

Distribution Outage Record Review

Distribution Planned Switching Log

Distribution Unplanned Outage Record

Distribution Unplanned Switching Log

Local Distribution Control Center Emergency Plans

Outage Coordination Information

Outage Logs

Outage Notifications

Outage Planning and Operating Plans

Outage Reports

Outage Requests

Outage Schedules

Outage Verification Information

Remedial Action Scheme (RAS) Misoperation Sequence of Events

Root Cause Analyses Reports

Record Category ID: OPS0300 | Record Category Name: Permits - Temporary - Electric T&D

Trigger Event: Expired

Retention Period: ACT+ 1 year

Description: Records related to all types of temporary permits, plans and registrations related to electric T&D operations.

Examples:

Daily Operating Permits

Record Category ID: OPS0330 | Record Category Name: Permits - Temporary - Power Generation

Trigger Event: Expired

Retention Period: ACT+ 1 year

Description: Records related to all types of temporary permits, plans and registrations related to power generation operations, including hydroelectric, fossil, photovoltaic, and fuel cell generation assets.

Examples:

Daily operating permits

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: OPS0400 | Record Category Name: Asset Plant Maintenance Records - Electric T&D

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Records related to the daily maintenance and operations of plant personnel, facilities, sites, equipment, or support structures that provide or assist the provision of electric T&D service to residential, commercial or industrial customers.

Examples:

- Asset PM Requests
- Asset PM Testing Information
- Warning Tags

Record Category ID: OPS0500 | Record Category Name: Research and Development Records - Approved - Electric T&D

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Records related to approved projects or activities associated to the research and development of new electric T&D assets or services, or, the improvement of existing electric utility assets or services.

Examples:

- Approved Research and Development (R&D) Business Cases and Requests
- Management Approvals
- Memorandums of Commitment
- Research and Development (R&D) Final Reports

Record Category ID: OPS0520 | Record Category Name: Research and Development Records - Approved - Power Generation

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Records related to approved projects or activities associated to the research and development of new power generation assets or services, or, the improvement of existing power generation assets or services.

Examples:

- Management Approvals
- Memorandums of Commitment
- R&D Business Cases & Requests
- R&D Final Report

Record Category ID: OPS0600 | Record Category Name: Research and Development Records - Not Approved - Electric T&D

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to unapproved projects or activities associated to the research and development of new electric T&D assets or services, or, the improvement of existing utility assets or services.

Examples:

- Denied Research and Development (R&D) Business Cases & Requests
- Management Denials

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: OPS0620 | Record Category Name: Research and Development Records - Not Approved - Power Generation

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to unapproved projects or activities associated to the research and development of new power generation assets or services, or, the improvement of existing power generation assets or services.

Examples:

- Management Denials
- R&D Business Cases & Requests
- R&D Final Report

Record Category ID: OPS0900 | Record Category Name: Load Supply & Forecasting Records - Electric T&D

Trigger Event: End of calendar year

Retention Period: ACT+ 10 years

Description: Records related to identifying, forecasting and planning changes or upgrades to the grid system to meet customer needs and/or to comply with supplier contractual or operational requirements. Daily usage forecasts included under Usage Records.

Examples:

- Assessment Study Report
- Electric Transmission Grid Expansion Plan
- Electric Transmission Reliability Assessment Study Report
- Facility Rating Document (F01)
- Generation Interconnection Study Reports
- Generator Model Validation Reports
- Instrumentation Recordings
- Line Capacitor Readings
- Line Regulator Readings
- Load Curves
- Load Data (Circle Charts)
- Load Forecast
- Load Growth Projections
- Load Reports
- Monthly Substation Load Reads
- Power Supply Load Forecast (PSLF) Power Flow Models
- Preliminary Project Reports (PPRs)
- Recloser Readings
- Retail Load Interconnection Study Reports
- Studies for Other PG&E Departments
- Substation Meter Readings (Half Hour Sheets)
- Summer Assessment Forecasts
- Wholesale Load Interconnection Study Reports

Record Category ID: OPS1110 | Record Category Name: Supply & Forecasting Records - Power Generation

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to identifying, forecasting and planning the transfer and delivery of power generation and water supplies to meet customer needs and/or to comply with supplier contractual or operational requirements.

Examples:

- Instrumentation Recordings
- Load Curves
- Load Data (Circle Charts)
- Load Forecast
- Load Growth Projections
- Load Reports
- Operating (Statistical) Reports

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Electric Operations - Record Categories

Record Category ID: OPS1200 | Record Category Name: Electricity Usage Records - Electric T&D

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to PG&E's electric T&D usage data, including data related to smart meter usage.

Examples:

- Billed Usage Data
- Daily Forecast Reports
- Daily Usage Information
- Meter Usage Data

Record Category ID: OPS1320 | Record Category Name: Asset Plant & Maintenance Records - Power Generation

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Records related to the daily maintenance and operations of power generation personnel, facilities, sites, equipment, or support structures that provide or assist the provision of utility service to residential, commercial or industrial customers.

Examples:

- Asset PM Requests
- Asset PM Testing Information
- Warning Tags

Record Category ID: PLN0710 | Record Category Name: Strategic Planning Records - Electric T&D

Trigger Event: Superseded

Retention Period: Life of Company

Description: Records related to documenting PG&E's electric T&D strategic plans.

Examples:

- Annual Operating Strategic Plans (S1s)
- Business Area Strategic Plans
- Growth Forecasts
- Strategic Initiative Plans

Record Category ID: PLN0740 | Record Category Name: Strategic Planning Records - Power Generation

Trigger Event: Superseded

Retention Period: Life of Company

Description: Records related to documenting PG&E's power generation strategic plans.

Examples:

- Annual Operating Strategic Plans (S1s)
- Business Area Strategic Plans
- Growth Forecasts
- Strategic Initiative Plans

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: REG0410 | Record Category Name: Regulatory and Compliance Reporting Records - Electric T&D

Trigger Event: End of calendar year

Retention Period: ACT+ 10 years

Description: Records related to PG&E's compliance with city, county, state and federal regulatory requirements and reporting for electric T&D operations. Does not include CPUC filings or authorizations.

Examples:

- All Regulatory Reports Submitted to External Third Parties (e.g., FERC, NERC)
- Responses to Data Requests from CAISO, NERC, WECC, FERC

Record Category ID: REG0440 | Record Category Name: Regulatory Reporting Records - Power Generation

Trigger Event: End of calendar year

Retention Period: ACT+ 10 years

Description: Records related to PG&E's compliance with city, county, state and federal regulatory requirements and reporting for power generation operations, including hydroelectric, fossil, photovoltaic, and fuel cell generation assets.

Examples:

- All Regulatory Reports Submitted to External Third Parties (e.g., FERC, NERC)
- Responses to Data Requests from NERC, WECC, FERC

Record Category ID: SER1440 | Record Category Name: Permits - Permanent - Power Generation

Trigger Event: Expired

Retention Period: Life of Company

Description: Records related to all types of permanent licenses, amendments, permits, plans and registrations related to power generation operations, including hydroelectric, fossil, photovoltaic, and fuel cell generation assets. Does not include temporary permits such as daily operating permits.

Enterprise Programs - Record Categories

Record Category ID: GOV0900 | Record Category Name: Records Management Records - Operations

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to the daily management, monitoring and tracking of records and information management services.

Examples:

- Data Inventory Logs
- Destruction Candidate Reports
- Document Inventory Logs
- Program Implementation Documents
- RFP Support Documents

Record Category ID: GOV1000 | Record Category Name: Records Management Records - Data & Document Inventories

Trigger Event: Superseded

Retention Period: ACT+ 1 year

Description: Records related to the collection, identification and inventory of PG&E data and documents created, generated, and used by each line of business.

Record Category ID: GOV1100 | Record Category Name: Records Management Records - Destruction

Trigger Event: End of calendar year

Retention Period: Life of Company

Description: Records related to PG&E's destruction approvals and destruction certificates for records and information.

Examples:

- Destruction Certificates
- Destruction Reports

Record Category ID: GOV1200 | Record Category Name: Records Management Records - Retention

Trigger Event: Superseded

Retention Period: Life of Company

Description: Records related to PG&E's records retention policy.

Examples:

- Records Retention Schedule

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

External Affairs and Public Policy - Record Categories

Record Category ID: CAF0200 | Record Category Name: Corporate Event Planning Records

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to planning, developing, and implementing PG&E's community-facing public relations events for external audiences.

Examples:

- After Action Reports (AARs)
- Attendance Lists
- Display Setups
- Event Planning Documents
- Event Presentations
- Event Promotional Materials
- Event Schedules

Record Category ID: CAF0300 | Record Category Name: Corporate Relations Records - External

Trigger Event: End of calendar year

Retention Period: ACT+ 6 years

Description: Records related to PG&E's public relations communications to and from external 3rd parties and organizations, including the media. Does not include materials related to external event planning or marketing and advertising.

Examples:

- Corporate Photographs and Images
- Corporate Responsibility Reports
- Media Alerts
- News Releases/Statements
- Presentations
- Press kits
- Special Project Communications
- Speeches

Record Category ID: CAF0400 | Record Category Name: Corporate Relations Records - Internal

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to PG&E's internal corporate communications to and from internal parties and stakeholders (e.g., employees, management, executives.)

Examples:

- Company Presentations (internal)
- Company Publications (internal)
- Corporate Posters (internal)
- Corporate Responsibility Memorandums
- Employee Announcements
- Employee Newsletters
- Executive Biographies
- Mission Booklets

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

External Affairs and Public Policy - Record Categories

Record Category ID: CAF0500 | Record Category Name: Government Relations Records - Local, State & Federal

Trigger Event: End of calendar year

Retention Period: ACT+ 6 years

Description: Records related to PG&E's communication to and from government-related parties and organizations. Includes legislative review and development and federal affairs and corporate sustainability materials.

Examples:

- Campaign Statements
- Disclosure Forms
- Donor Reports
- Federal Affairs and Corporate Sustainability Documents
- Lobbyist Reports (state and federal)

Record Category ID: CAF0600 | Record Category Name: Grant Records

Trigger Event: End of grant or audit, whichever is later

Retention Period: ACT+ 7 years

Description: Records related to PG&E's management and administration of grants awarded by PG&E to community and external 3rd parties.

Examples:

- Community Investment Grant Files
- Grant Applications
- Grant Correspondence
- Grant Decision Documents - Acceptance and Denials
- Grant Submission Documents

Record Category ID: CAF0700 | Record Category Name: Advertising Records

Trigger Event: End of calendar year

Retention Period: ACT+ 6 years

Description: Records related to advertising PG&E's brand(s) and corporate identity, customer programs, events or products and services.

Examples:

- Advertising Materials
- Brand Brochures and Catalogs
- Logos
- New Service Announcements

Record Category ID: CAF0750 | Record Category Name: Solutions Marketing Records

Trigger Event: End of calendar year

Retention Period: ACT+ 6 years

Description: Records related to planning and promoting new or existing PG&E products and services.

Examples:

- Market Analysis Studies
- Market Data and Research
- Marketing Campaign Materials
- Marketing Materials

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: reg0240 | Record Category Name: External Affairs and Public Policy Planning Records

Trigger Event: End of calendar year

Retention Period: ACT+ 10 years

Description: Records related to activities associated with planning, developing and implementing PG&E communication and External Affairs and Public Policy strategies for both external and internal audiences.

Examples:

- Electric Quarterly Report (including FERC forms)
- FERC-920: Electric Quarterly Report
- All Regulatory Documents Submitted to FERC
- FERC-580: Interrogatory on Fuel and Energy Purchase Prices
- Other FERC Cases and Related Documents
- Cost of service filings (i.e., transmission owner tariff, wholesale distribution tariff rate cases)
- FERC-730: Report of Transmission Investment Activity

Finance & Risk - Record Categories

Record Category ID: FIN0100 | Record Category Name: Accounts Payable Records

Trigger Event: End of calendar year

Retention Period: ACT+ 10 years

Description: Records related to the review, management and authorization of the payment of PG&E's financial obligations.

Examples:

- Accounts Payable Correspondence
- Corporate Credit Card Information
- Credit Applications
- Credit Reports
- Electronic Fund Transfer Documents
- Employee Expense Reimbursements
- Employee Expense Reports
- Expenditure Authorizations
- Invoices
- Payments & Payment Reports

Record Category ID: FIN0200 | Record Category Name: Accounts Receivable Records

Trigger Event: End of calendar year

Retention Period: ACT+ 10 years

Description: Records related to the receipt of monies owed to PG&E by customers, employees or others, and the activities related to the management of accounts receivable.

Examples:

- Accounts Receivable Correspondence
- Billing Reconciliations
- Cash Receipts
- Collection Agency Reports
- Credit Memos
- Customer Checks Returned for Insufficient Funds

Record Category ID: FIN0400 | Record Category Name: Financial Planning & Analysis Records

Trigger Event: End of calendar year

Retention Period: ACT+ 10 years

Description: Records related to analyzing expenses and revenues in order to allocate costs, budget, support journal entries or valuations and compile financial reports for both internal and external use.

Examples:

- Actual vs. Plan Accounting Reports
- Cash Flow Reports
- Cash Forecast Reports (monthly)
- Cost allocations
- Cost Analysis Reports
- EPS/ECS reports (monthly)
- IIC Memorandums Items Impacting Comparability
- Review/Status Reports (monthly)

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: FIN0450 | Record Category Name: SOX Records

Trigger Event: End of calendar year

Retention Period: ACT+ 7 years

Description: Records related to analyzing, documenting and reviewing financial process, controls and procedures to ensure compliance with internal and external requirements.

Examples:

- Affiliate Order Request Forms
- Business Process Owner Certificates
- Chart of Account Request Forms
- Daily Balancing
- Deficiency Memos
- Evaluation
- Officer Back-up Certificates
- Process Narratives
- Quarterly Deficiency
- Risk Control Matrix
- Test Documents (Quarterly)
- Walkthrough Support
- Working Papers Files

Record Category ID: FIN0500 | Record Category Name: Financial Reporting Records

Trigger Event: End of calendar year

Retention Period: ACT+ 10 years

Description: Records related to financial information filed with external parties such as SEC, FERC and CPUC.

Examples:

- 10k and 10Q Reports
- Accounting Treatment Memos
- Annual Report on Significant Utility - Affiliate Transactions
- Consolidated Financial Statements
- Financial Statement Variance Analyses
- RADs
- Regulatory Filing (May 1)
- SEC, FERC and CPUC Financial Filings
- Summary of Electric Retail Revenue Analysis (SERRA)
- Summary of Gas Revenue Analysis (SOGRA)
- Weighted Average Shares Calculations

Record Category ID: FIN0600 | Record Category Name: General & Subsidiary Ledgers

Trigger Event: End of calendar year

Retention Period: ACT+ 50 years

Description: Records related to the general and subsidiary ledgers related to financial transactions including journal entries, journal entry supporting document, authorization of journal entries and account reconciliations.

Examples:

- Account Reconciliations
- General and Subsidiary Ledger
- Journal Entries and Supporting Documents
- Plant Accounting Ledgers & Sub Ledgers
- Plant Additions & Retirements Ledgers

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: FIN0700 | Record Category Name: Investor Relations Records

Trigger Event: End of calendar year

Retention Period: ACT+ 10 years

Description: Records related to planning, conducting and documenting PG&E's investor events, including earnings calls.

Examples:

- Earnings and Event Presentations
- Earnings and Event Transcripts
- Email Communication with Investors
- Market Summary

Record Category ID: FIN0800 | Record Category Name: Payroll Records

Trigger Event: End of calendar year

Retention Period: ACT+ 6 years

Description: Records related to maintaining, managing and documenting the payroll function: employee master data, earning and deductions and payroll tax reporting.

Examples:

- Adjustments
- Attendance Information
- Direct Deposit Authorizations
- Employee Loan Deductions
- Employee Salary and Status Changes
- Employment and Wage Verifications
- Incentive Awards
- Military Orders
- Military Pay
- New Hire Paperwork
- Off-cycle Payments
- Payments
- Payroll Processing and Closing Documents
- Payroll System Testing Documents
- Payroll Tax Deposit and Tax Reporting
- Relocation Payments
- Signing Bonuses
- Taxable Fringe Benefits
- Time Reporting Data
- Tuition Payments

Record Category ID: FIN0900 | Record Category Name: Tax Records - Federal & State

Trigger Event: End of calendar year

Retention Period: Life of Company

Description: Records related to all types of tax assessments, tax returns and work papers related to federal and state tax returns.

Examples:

- Filing Procedures
- Property Tax Information
- Tax Appeals
- Tax Assessments
- Tax Compliance Documents
- Tax Correspondence
- Tax Extensions
- Tax Forecasts
- Tax Invoices
- Tax Planning and Analysis Reports
- Tax Returns
- Tax Statements
- Tax Waivers and Exemptions

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: FIN0910 | Record Category Name: Tax Records - Property Tax

Trigger Event: End of calendar year

Retention Period: Life of Company

Description: Records related to all types of tax assessments, tax returns and work papers related to property tax.

Examples:

- Filing Procedures
- Property Tax Information
- Tax Appeals
- Tax Assessments
- Tax Compliance Documents
- Tax Correspondence
- Tax Extensions
- Tax Forecasts
- Tax Invoices
- Tax Planning and Analysis Reports
- Tax Returns
- Tax Statements
- Tax Waivers and Exemptions

Record Category ID: FIN1000 | Record Category Name: Treasury Management Records

Trigger Event: End of calendar year

Retention Period: ACT+ 10 years

Description: Records related to managing and tracking banking and investment activities.

Examples:

- Bank Statements
- Dividend Payment Documents
- Merchant Activity
- Reconciliations
- Trust Statements
- Wire Transfers

Record Category ID: FIN1100 | Record Category Name: Timekeeping Records

Trigger Event: End of calendar year

Retention Period: ACT+ 6 years

Description: Records related to documenting employee timekeeping.

Examples:

- Time Summary Reports and Supporting Documents for Wage Computations
- Timesheet Corrections
- Timesheets

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: FIN1300 | Record Category Name: Loans, Credit, Investments & Securities Records

Trigger Event: Issuance of securities

Retention Period: ACT+ 5 years

Description: Records related to external financing arrangements and PG&E's debt, bonds and equity securities and issuance of stock.

Examples:

- Closing Documents (debt)
- Credit Agreements and Amendments
- Dividend Checks
- ESOP Related Documents
- Indentures
- Issuance of Shares/Closing Documents
- Letters of Credit
- Prospectus
- Purchase Plan Analyses
- Receivables Facility Agreements
- Registration Statements

Record Category ID: FIN1400 | Record Category Name: Trading and Futures Records

Trigger Event: End of contract

Retention Period: ACT+ 5 years

Description: Records related to trading, derivatives, futures, and similar financial agreements related to the acquisition of energy, including documentation related to efforts to control customer rates (across jurisdictions).

Examples:

- Aggregation Information
- Basis Trading Information
- Broker Deals
- Collateral and Exposure Reports
- Collateral Instruments
- Forward Price Risk Management Documents
- Gas Trading Contracts (financial)
- Hedge Documents
- NYMEX Trading Information
- Pricing Projections
- Structured Risk Management Product Information
- Weather-triggered Pricing Options Information

Record Category ID: FIN1500 | Record Category Name: Market and Credit Risk Management Records - Governance & Controls

Trigger Event: When superseded

Retention Period: ACT+ 3 years

Description: Records related to the governance and management of financial risks associated to PG&E's operations.

Examples:

- Analysis/Modeling Records
- Authorizations (signing, trader)
- Calculations
- Corporation and Utility Risk Management Policies and Procedures
- Delegations of authority
- Guidance and Risk Policy Documents
- Price Reports

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Finance & Risk - Record Categories

Record Category ID: GOV0650 | Record Category Name: Insurance Records

Trigger Event: Superseded

Retention Period: ACT+ 7 years

Description: Records related to PG&E's commercial insurance policies

Examples: Property Loss Control Files

Record Category ID: GOV0775 | Record Category Name: Investigations Records - Litigation

Trigger Event: End of investigation, or close of , whichever is later

Retention Period: ACT+ 10 years

Description: Records related to the planning, management and operation of the company's litigation or criminal investigations.

Examples: Investigation Case Files, Letters, Reports and Supporting Information

BP09_ATCH01-35

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: EDC0110 | Record Category Name: Engineering, Design & Construction Records - Gas

Trigger Event:

Retention Period: Permanent

Description: All records associated with the design and construction of Transmission and Distribution gas utility assets.

Examples:

Area Classification
Business Cases
Distribution Change Order Requests
Distribution Foreign Prints
Distribution Issue for Construction Drawings
Distribution P&ID Drawings
Distribution Project Authorizations
Distribution Relief Valve Documentation
NDE SMYS Test Records
As-Built Records: Group B
As-Built Records: Group A
Distribution As-Built Records
Distribution Construction Drawings and Permits
Distribution Gas Piping Drawings
Distribution Job Estimates
Distribution Piping & Instrumentation Diagrams (P&IDs)
Distribution Project Scope Documents
Distribution Site and/or Job Specific Work Procedures
Potential Change Orders
Advance Authorizations (AA)
As-Built Records: Group C
Distribution Bill of Materials
Distribution Critical Doc List of Facility
Distribution Gas Service Records
Distribution Material Failure/Problem Report Records
Distribution Project Administration Documents
Distribution Release to Construction Package
HCA Determination Documents

Record Category ID: EDC0120 | Record Category Name: Transmission Pipeline Repair

Trigger Event: Life of Asset

Retention Period: Permanent

Description: Records related to CPUC General Order 112 F 145.1

(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.

Examples:

A-Forms
Transmission Records as required by TD-4461S
Gas Transmission Non As-Built (Group B) Checklist
Transmission Project Job Files
Transmission Records as required by TD-4462P-21
X-Rays for As-Built Transmission and Stations
Transmission Records as required by TD-4461P-22

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).
Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Gas Operations - Record Categories

Record Category ID: EDC0140 | Record Category Name: Transmission Patrol, Surveys, Inspections and Tests

Trigger Event:

Retention Period: Permanent

Description: Records related to CPUC General Order 112 F 145.1:

(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 or until the next patrol, survey, inspection, or test is completed, whichever is longer.

Examples:

Transmission Patrol Documents (all types)
Transmission Periodic Leak Surveys
Transmission Physical Inspection Reports
Transmission Pipeline Inspection Records
Transmission Pipeline Inspection Reports
Transmission Pipeline Leak Surveys
Transmission Special Leaks Survey

Record Category ID: EDC0210 | Record Category Name: Geographic Information System (GIS) Records - Gas

Trigger Event: Superseded

Retention Period: Superseded

Description: Records and data related to current geographical and asset information for all gas operating regions as contained in PG&E's GIS.

Examples:

LOC (Class Location)
Standardized Structure Layer

BP09_ATCH01-37

Record Category ID: EDC0400 | Record Category Name: Integrity Management Records - Gas

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Records related to the planning, development and implementation of PG&E's distribution and transmission integrity management programs.

Examples:

3rd Party Damage Reports
Analysis Studies
Corrosion Reports & Findings
Defect Reports & Findings
Encroachment Reports & Findings
Ground Movement Reports & Findings
Integrity Management Plans
Other Documents Related to Maximum Allowable Operating Pressure (MAOP) Data
Patrol Forms & Findings
Project Binders

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).
Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Gas Operations - Record Categories

Record Category ID: EDC0500 | Record Category Name: Leak Survey & Inspection Records - Gas

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Records related to surveying and inspecting gas transmission and distribution assets.

Examples:

- Distribution Patrol Documents (all types)
- Distribution Periodic Leak Surveys
- Distribution Physical Inspection Reports
- Distribution Pipeline Inspection Records
- Distribution Pipeline Inspection Reports
- Distribution Pipeline Leak Surveys
- Distribution Pressure Test Reports
- Distribution Special Leaks Survey

Record Category ID: EDC0610 | Record Category Name: Locating Records - 811 - Gas

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to finding and marking the location of PG&E gas utility assets as generated in response to requests from the 811 public service center.

Examples:

- 811 Communications
- 811 Field Reports
- 811 Notifications of Findings
- 811 Ticket Information

Record Category ID: EDC0710 | Record Category Name: Locate and Mark Records - Gas

Trigger Event: Life of Asset

Retention Period: ACT+ 5 years

Description: Records related to finding, marking and mapping the location of gas utility assets.

Examples:

- Comparison Reports
- Field Reports
- Gas Distribution Maps
- Gas Transmission Maps
- Locating Communications
- Mapping Advancement Program Information
- Notifications of Findings

Record Category ID: EDC1010 | Record Category Name: Policies, Procedures & Standards - Operational & Technical - Gas

Trigger Event: Superseded

Retention Period: Life of Company

Description: Records related to planning and developing policies, procedures and standards related to gas utility assets and operations. Does not include site and/or job specific work procedures - see Engineering, Design and Construction Records.

Examples:

- All Design Specifications
- All Engineering and Design Calculations
- All Engineering and Design Models
- All Engineering Manuals
- All Maintenance Specifications
- All Measurement and Control Specifications
- All Technical Specifications

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Gas Operations - Record Categories

Record Category ID: EDC1100 | Record Category Name: Quality Control & Improvement Records - Gas

Trigger Event: Life of Asset **Retention Period:** ACT+ 10 years

Description: Records related to the planning, development, implementation and monitoring and tracking of PG&E's quality control and improvement activities for gas operations.

Examples:

- Archived QE&I Gas Event Reports
- Archived QE&I Internal Reviews & Investigations
- Assessment Documents (Lean Six Sigma Improvement Projects)
- GSR QC Explanation of Errors Data
- GSR QC Plastic Connection Test Forms
- GSR QC Preliminary Summary of Review Forms
- GSR QC Review Reports
- GSR QC Review Totals by GSR
- GSR QC Reviewers Summary Forms
- GSR QC Safety Brochure Tracker
- GSR TCI Installation Quality Work Reviews
- Leak Survey Detailed Processes
- QC Leak Repair Validation Program Detailed Process
- QC Leak Survey Processes & Assessments
- QC Next Day Assessments
- QC Re-Dig Assessment Documents (in development)

Record Category ID: OPS0055 | Record Category Name: Incident Reporting Records - Gas

Trigger Event: End of calendar year **Retention Period:** Life of Company

Description: Records related to the requirement that PG&E report significant gas utility incidents to the CPUC in a timely manner.

Examples:

- Accident Notice and Written reports

Record Category ID: OPS0110 | Record Category Name: Maintenance Records - Gas

Trigger Event: Life of Asset **Retention Period:** ACT+ 10 years

Description: Records related to the monitoring and reporting of daily maintenance and testing of gas assets.

Examples:

- Cathodic Protection Reports
- Certificates of Calibration
- Compressor Operation Reports
- District Regulator Data Sheets
- District Regulator Station Maintenance Records
- Gas Dehydration Plant Inspection Reports
- Gas Operating Changes
- Gas Well Meter Reports
- Instrument Calibrations
- Liquid Removal Records
- Liquid Removal Records
- Material Problem Reports
- Monthly Odorization Reports
- Monthly Report Of Process Chromatograph
- Non-Compliance Notices
- Non-Permit Confined Space Certifications
- Odor Intensity Reports
- Pressure Charts
- SCADA Documents
- Valve Automation Functional Checkout Procedures

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Gas Operations - Record Categories

Record Category ID: OPS0210 | Record Category Name: Outage Records - Gas

Trigger Event: End of calendar year

Retention Period: ACT+ 2 years

Description: Records related to identifying, managing, restoring and reporting on gas supply outages for residential, commercial or industrial customers.

Examples:

- Outage Coordination Information
- Outage Logs
- Outage Notifications
- Outage Planning and Operating Plans
- Outage Reports
- Outage Requests
- Outage Schedules
- Outage Verification Information
- Root Cause Analyses Reports

Record Category ID: OPS0310 | Record Category Name: Permits - Temporary - Gas

Trigger Event: Expired

Retention Period: ACT+ 1 year

Description: Records related to all types of temporary permits, plans and registrations related to gas utility operations.

Examples:

- Daily Operating Permits

Record Category ID: OPS0510 | Record Category Name: Research and Development Records - Approved - Gas

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Records related to approved projects or activities associated to the research and development of new gas utility assets or services, or, the improvement of existing gas utility assets or services.

Examples:

- Management Approvals
- Memorandums of Commitment
- R&D Business Cases & Requests
- R&D Final Report

Record Category ID: OPS0610 | Record Category Name: Research and Development Records - Not Approved - Gas

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to unapproved projects or activities associated to the research and development of new gas utility assets or services, or, the improvement of existing gas utility assets or services.

Examples:

- Management Denials
- R&D Business Cases & Requests
- R&D Final Report

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Gas Operations - Record Categories

Record Category ID: OPS1000 | Record Category Name: Supply & Forecasting Records - Gas

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to identifying, forecasting and planning the transfer and delivery of gas supplies to meet customer needs and/or to comply with supplier contractual or operational requirements.

Examples:

- 12-Month Operating Plan
- 5C Cumm by Producers (R717GS)
- 5C Expense Statement (R5c1GS)
- Actual Deliveries and Adjustments by California Production Meter (605)
- Annual Report of Natural and Supplemental Gas Supply and Disposition
- Approval to Revise MAOP/MOP Transmission and Gathering Lines (TD-4125P-04-F01)
- California Energy Commission (CEC) 1308A Schedules 1 and 2
- California Production Imbalance Statement (600)
- Capacity Planning Models & Analysis (LT&D Planning)
- Cashout Imbalance Summary
- Chevron Weekly Meter Report
- Confirm & Schedule Metric
- Core Conversion Factor Report
- CPBA Cash Out Statement (603)
- CPBA Cash Out Summary (602)
- CPBA Monthly Summary (607)
- Curtailment Database
- Customer Nominations
- Customer Specific Adjustments
- Daily Confirm/Schedule Reports
- Daily Gas Operating Reports
- Detail of Billing Compression and Dehydration Charges
- EIA 857
- Elevated Pressure Requests
- FERC Form 2 Pages 312 and 313
- FERC Form 2 Pages 512 and 513
- FERC Reporting of Pages 313 - Stanpac
- FERC Reporting of Pages 518 and 565-1
- Form EIA 17
- Form EIA 191
- Gas Department Use (GDU) Reporting
- Gas Storage Reconciliation
- Gill - Ordering Paragraph 23(a)(i)
- Gill - Ordering Paragraph 23(a)(ii)
- Gill - Ordering Paragraph 23(a)(ii)
- Gill Average Monthly Storage Injections and Withdrawals
- Gill Capacity
- Green House Gas Subpart NN
- GTCC Forecasting Tools
- Independent Storage Provider Report
- Line Pack Gas Report
- Monthly Report of Natural Gas Purchases and Deliveries to Consumers
- Monthly Underground Storage Report
- PG&E Storage Inventory Position

BP09_ATCH01-41

Record Category ID: OPS1210 | Record Category Name: Usage Records - Gas

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to PG&E's gas usage data, including data related to smart meter usage.

Examples:

- Billed Usage Data
- Daily Forecast Reports
- Daily Usage Information
- Meter Usage Data

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: OPS1250 | Record Category Name: Digital Audio, Audiovisual or Imagery Records (Supporting) - Gas

Trigger Event: Transfer of needed data to document, file, system of record or other format for long-term use; or completion of pertinent project; whichever is later.

Retention Period: ACT+ 1 year

Description: Digital audio, audiovisual, imagery or other similar records created in support of other data gathering and decision processes within PG&E's Gas Operations. Digital audio, audiovisual and digital imagery records include, but are not limited to, video recordings, still photographs (e.g., aerial photographs), filmstrips, sound recordings, and other multimedia items created and used in support of gas utility operations (e.g., inspections, cross bore management, high consequence area identification, integrity management). These records are created in support of another process (e.g., engineering design and construction, leak survey, maintenance and inspections), and all necessary information is captured in a separate document, file, system of record or other format for long-term use. These records have a limited useful life and are not relied on long-term for gas operations activities.

Examples:

- Filmstrips
- Images Captured on any Form of Digital Media
- Photographs (e.g., aerial photos)
- Sound Recordings
- Video Recordings

Record Category ID: OPS1300 | Record Category Name: Work Orders & Maintenance Records - Gas

BP09_ATCH01-42

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Records related to the daily maintenance and operations of plant personnel, facilities, sites, equipment, or support structures that provide or assist the provision of gas service to residential, commercial or industrial customers.

Examples:

- Asset Work Order Requests
- Asset Work Order Testing Information
- Asset Work Order Verification Information
- Asset Work Orders
- Red Tag Notices
- Red Tags
- Warning Tags

Record Category ID: PLN0720 | Record Category Name: Strategic Planning Records - Gas

Trigger Event: Superseded

Retention Period: Life of Company

Description: Records related to documenting PG&E's gas utility strategic plans.

Examples:

- Annual Operating Strategic Plans (S1s)
- Business Area Strategic Plans
- Growth Forecasts
- Strategic Initiative Plans

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: PLN0800 | Record Category Name: Wholesale Marketing Records - Gas

Trigger Event: End of calendar year

Retention Period: ACT+ 7 years

Description: Records related to the planning, development, implementation and monitoring and tracking of PG&E's wholesale marketing projects and activities.

Examples:

- 550 Report Results
- Analysis - Gas Purchased
- Application for Gas Transmission Services
- Capacity Utilization Reports
- Cash Out Rate Reports
- Emergency & Relocation Information
- FERC Pipeline Postings
- Firm Capacity Holdings Spreadsheets
- Index Deal Pricing Spreadsheets
- Large Load Projects - Working Files
- Line 401 Direct Connection Applications
- Market Concentration Reports
- MASIS Database - Natural Gas Pipeline Flows, Storage, Prices
- Negotiated Contracts Reports

Record Category ID: REG0420 | Record Category Name: Regulatory Reporting Records - Gas

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to PG&E's compliance with city, county, state and federal regulatory requirements and reporting for gas utility operations. Does not include CPUC filings or authorizations.

Examples:

- All Regulatory Reports Submitted to External Third Parties (e.g., FERC, etc.)

Human Resources - Record Categories

Record Category ID: HRS0100 | Record Category Name: Benefit Administration Records

Trigger Event: Plan termination

Retention Period: Until no longer required for determination of retirement benefits

Description: Records related to the planning and administration of benefits provided by PG&E to employees.

Examples:

- Benefit Plan Studies
- Dependent forms/requests
- Employee Benefit Enrollment Requests
- Life Insurance Requests

Record Category ID: HRS0200 | Record Category Name: Benefit Plan Records

Trigger Event: End of benefit provided or applicable labor agreement

Retention Period: Until no longer required for determination of retirement benefits

Description: Records related to developing, negotiating and maintaining all types of PG&E benefits, including benefits such as retirement accounts, savings accounts, employee assistance and alternate work schedules.

Examples:

- Alternate Work Schedules and Approvals
- Benefit Plan Amendments
- Benefit Plans
- Benefit Requirement Documents
- Employee Assistance Case Files
- Employee Benefit Payment Information
- Employee Benefit Receipt Records
- Legal Benefit Notices
- Retirement Plan Information (includes 401K)
- Saving Plans
- Summary Material Modifications
- Summary Plan Descriptions

Record Category ID: HRS0300 | Record Category Name: Compensation Administration Records

Trigger Event: End of calendar year

Retention Period: ACT+ 7 years

Description: Records related to the planning and administration of PG&E's compensation.

Examples:

- Long Term Incentive Plan(s)
- Market Statistics
- Salary Compensation Plans
- Salary Schedules and Approvals
- Wage and Benefit Surveys

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: HRS0400 | Record Category Name: Disability & Leave Records - Family Medical Leave (FMLA)

Trigger Event: End of leave

Retention Period: ACT+ 3 years

Description: Records related to the documentation of leave activity associated to the Family Medical Leave Act.

Examples:

- FMLA Documents
- Medical Certifications Required by FMLA
- Medical Records Submitted in Support of Family Medical Leave

Record Category ID: HRS0450 | Record Category Name: Disability & Leave Records - Short & Long Term

Trigger Event: Date of injury, or from end of leave, or (for Workers' Compensation) when no future claims are anticipated (which may be after the employee's death), whichever is later

Retention Period: ACT+ 5 years

Description: Records related to the documentation of employee leave and disability, including information on the safe return to work from a personal or occupational injury.

Examples:

- Leave of Absence Documents
- Occupational Injury Records
- Workers' Compensation Files (includes personal case histories/illness histories)

Record Category ID: HRS0500 | Record Category Name: Human Resources Compliance Records

Trigger Event: End of calendar year

Retention Period: ACT+ 7 years

Description: Records related to regulatory and compliance reporting activities associated to human resources.

Examples:

- Affirmative Action Reports
- Demographic and Location Reported Information
- Equal Employment Opportunity Reports

Record Category ID: HRS0600 | Record Category Name: Human Resources Management Records

Trigger Event: End of calendar year

Retention Period: ACT+ 7 years

Description: Records related to planning and managing PG&E's human resources function.

Examples:

- Employee Surveys and Results
- Management Plans
- Qualifications Catalog
- Statistical Reports
- Trending Analyses

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: HRS0700 | Record Category Name: Immigration & Naturalization Records

Trigger Event: Termination of employment **Retention Period:** ACT+ 3 years

Description: Records related to documenting and tracking immigration and naturalization information.

Examples:

- I-9s
- Immigration and Naturalization Files

Record Category ID: HRS0800 | Record Category Name: Investigations Records - Human Resources

Trigger Event: Close of investigation **Retention Period:** ACT+ 5 years

Description: Records related to monitoring compliance with PG&E's corporate ethics policies and procedures.

Examples:

- Code of Conduct Investigations
- Equal Employment Opportunity Investigations
- Investigation Case Files
- Safety Investigations

Record Category ID: HRS0900 | Record Category Name: Labor Relations - Agreements & Grievance Administration

Trigger Event: End of agreement **Retention Period:** ACT+ 10 years

Description: Records related to labor relations agreements, including collective bargaining agreements, negotiation materials and grievances brought by unions on behalf of represented employees.

Examples:

- Arbitration Files
- Collective Bargaining Agreements
- Review Committee Grievance Decisions
- Review Committee Grievance Letters

Record Category ID: HRS0950 | Record Category Name: Labor Relations - Grievances

Trigger Event: End of agreement **Retention Period:** ACT+ 10 years

Description: Records related to grievances brought by unions or individuals against PG&E that are decided below the Review Committee level.

Examples:

- Grievance Files Resolved Below Review Committee
- Negotiation Preparation Packages
- Union Organizing Campaign Files
- Work Stoppage Contingency Plans

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Human Resources - Record Categories

Record Category ID: HRS1000 | Record Category Name: Personnel Records

Trigger Event: Termination of employment

Retention Period: ACT+ 6 years

Description: Records related to an individual's work history with PG&E, including employment information, work status, performance assessments, etc.

Examples:

- Appraisals and Evaluations
- Assessments
- Awards
- Certificates of Course Completion
- Continuing Education Records
- Corrective actions
- Employee Concerns and Other Reported Issues
- Employee Development Plans
- Employee Performance Reviews
- Employment Offer Letters
- Qualifications
- Severance Documents
- Status Changes

Record Category ID: HRS1100 | Record Category Name: Recruiting Records

Trigger Event: End of calendar year

Retention Period: ACT+ 2 years, unless Intercompany transfer in which case retention period is 8 years

Description: Records related to sourcing, recruiting, assessing and selecting, human resources for placement.

Examples:

- Applications (successful and unsuccessful)
- Employment Testing Materials
- Job Bidding (Union)
- Job Descriptions and Requisitions
- Job Postings
- Resumes
- Staff Member Referrals

Record Category ID: HRS1200 | Record Category Name: Training Records - Career Development

Trigger Event: Superseded

Retention Period: ACT+ 7 years

Description: Records related to planning, developing, maintaining and completing corporate training activities related to career development and expansion of employee knowledgebase regarding PG&E activities and operations.

Examples:

- Course Guidance Documents
- Lesson Planning Documents
- Needs Analyses Documents
- Other PG&E Learning Academy Documents
- Training Planning Documents

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: HRS1300 | Record Category Name: Training Records - Corporate Training & Certifications

Trigger Event: Superseded, or end of calendar year, whichever is later

Retention Period: ACT+ 7 years

Description: Records related to planning, developing, maintaining and updating training career development and knowledge-based training records for corporate training activities. Does not include training records related to specific technical training required by PG&E.

Examples:

- Course Descriptions and Materials
- Course Schedules
- Course Training Records
- Grade Reports
- Lesson Plans
- Training Curriculum and Scheduling Information
- Training Logs
- Training Manuals
- Training Rosters
- Training Tests and Results

Record Category ID: HRS1400 | Record Category Name: Training Records - Environment, Health & Safety Training & Certifications

Trigger Event: Life of asset, or termination of employee, whichever is later

Retention Period: ACT+ 6 years

Description: Records related to planning, developing, maintaining and completing training course materials, resources, schedules and rosters related to environment, health and safety activities and operations.

Examples:

- Assessment Documents
- Course Descriptions and Materials
- Course Schedules
- Grade Reports
- Lesson Plans
- On-the-job Training Checklists
- Training Curriculum and Scheduling Information
- Training Logs
- Training Manuals
- Training Rosters
- Training Tests and Results

Record Category ID: HRS1500 | Record Category Name: Training Records - Operational & Technical Training & Certifications

Trigger Event: Life of asset, or termination of employee, whichever is later

Retention Period: ACT+ 6 years

Description: Records related to planning, developing, maintaining and completing technical training course materials, resources, schedules and rosters related to gas and electric operations.

Examples:

- Assessment Documents
- Course Descriptions and Materials
- Course Schedules
- Grade Reports
- Lesson Plans
- On-the-job Training Checklists
- Training Curriculum and Scheduling Information
- Training Logs
- Training Manuals
- Training Rosters
- Training Tests and Results

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: HRS1600 | Record Category Name: Workforce Development Records

Trigger Event: End of calendar year

Retention Period: ACT+ 7 years

Description: Records related to the planning and management of PG&E's workforce development program.

Examples:

- Participant Correspondence
- Participant Specific Records
- Program Completion Information
- Test Results

Record Category ID: HRS1700 | Record Category Name: Workforce Management Records

Trigger Event: Superseded

Retention Period: ACT+ 7 years

Description: Records related to identifying and managing the size, type and quantity of workforce required to support PG&E's business operations.

Examples:

- Needs Analyses
- Resource & Staffing plans
- Workforce Strategy Documents

Information Technology - Record Categories

Record Category ID: ITS0100 | Record Category Name: Information Technology Records - Application Development and Operations

Trigger Event: Superseded or end of calendar year, whichever is later

Retention Period: ACT+ 2 years

Description: Records related to planning, building and running PG&E's internal technology applications and software.

Examples:

- Architecture
- Change Management Documents
- Design Documents
- Functional Requirements
- Network and Telecom Site Access Requests
- Operations Manuals/Run Books/Process Documents
- Platform Recovery Processes and Procedures
- Procedures
- Source Code Requirements
- Specification and Testing Documents

Record Category ID: ITS0200 | Record Category Name: Information Technology Records - Data Center Technology

Trigger Event: Superseded or end of calendar year, whichever is later

Retention Period: ACT+ 2 years

Description: Records related to planning, building and running PG&E's cloud, application hosting, converged infrastructure/servers, database, storage and data center facilities.

Examples:

- Architecture
- Change Management Documents
- Data Center Business Continuity
- Data Center Recovery Process and Procedures, etc.
- Data Center Site Access Requests
- Data Center Technology and Facility Standards
- Design Documents
- Non-Functional Requirements
- Operations Manuals/Run books/Process Documents
- Specification and Testing Documents Procedures

Record Category ID: ITS0300 | Record Category Name: Information Technology Records - Network Technology

Trigger Event: Superseded or end of calendar year, whichever is later

Retention Period: ACT+ 2 years

Description: Records related to planning, building, and running PG&E's physical IT infrastructure, including the IP network, LAN/WAN services, operational technologies (e.g., SCADA), transmission systems, telephony systems, mobile radio system and other IT common facilities.

Examples:

- Architecture
- Change Management Documents
- Design Documents
- IT Network and Telecommunications Technology Standards
- Network and Telecom Site Access Requests
- Network and Telecommunications Procedures
- Non-Functional Requirements
- Operations Manuals/Run Books/Process Documents
- Specifications and Testing Documents
- System Recovery Processes and Procedures, etc.

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Information Technology - Record Categories

Record Category ID: ITS0400 | Record Category Name: Information Technology Records - User Technology

Trigger Event: Superseded or end of calendar year, whichever is later

Retention Period: ACT+ 2 years

Description: Records related to planning, building and running PG&E's user-related technologies, including personal computers, laptops, field laptops, (AKA device services), and communication and collaboration platforms such as email and SharePoint.

Examples:

- Architecture
- Change Management Documents
- Design Documents
- IT User Technology Standards
- Non-Functional Requirements
- Operations Manuals/Run Books/Process Documents
- Specifications and Testing Documents
- System Recovery Processes and Procedures, etc.
- User Technology Procedures

Record Category ID: ITS0500 | Record Category Name: Information Technology Records - Security

Trigger Event: Technology related records superseded or end of calendar year, whichever is later

Retention Period: ACT+ 3 years

Description: Records related to planning, building and running PG&E's security technology and cyber security. Includes records related to identity and access, information protection, application protection, security information and intelligence, infra protection, network protection and remote access management.

Examples:

- Architecture
- Change Management Documents
- Design Documents
- IT Security Technology Standards
- Owners Manuals/Run Books/Process Documents/Assessment Reports
- Requirements
- Security Incident Reports
- Security Reviews
- Security Scan Results
- Security Technology Procedures
- Specifications
- Testing Documents
- Vulnerability Reports

Record Category ID: ITS0600 | Record Category Name: Information Technology Records - Mobile Technology

Trigger Event: Superseded or end of calendar year, whichever is later

Retention Period: ACT+ 2 years

Description: Records related to maintaining PG&E's IT mobile technologies including mobile management, development and user experience.

Examples:

- Architecture
- IT Mobile Technology Standards
- Operations Manuals/Run Books/Process Documents
- System Recovery Processes and Procedures
- Change Management Documents
- Mobile Technology Procedures
- Specifications and Testing Documents

Examples:

- Design Documents
- Non-Functional Requirements

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Information Technology - Record Categories

Record Category ID: ITS0700 | Record Category Name: Information Technology Records - Information Management Technologies

Trigger Event: Superseded or end of calendar year, whichever is later

Retention Period: ACT+ 2 years

Description: Records related to planning, building and running PG&E's IT information management technologies including Analytics, Records Management, Data Management, Integration and Content Management.

Examples:

- Architecture
- Change Management Documents
- Design Documents
- IT Information Management Technology Standards
- Operations Manuals/Run Books/Process Documents
- Requirements
- Specifications and Testing Documents
- System Recovery Processes and Procedures

Record Category ID: ITS0800 | Record Category Name: Information Technology Records - IT Operational Tools

Trigger Event: Superseded or end of calendar year, whichever is later

Retention Period: ACT+ 1 year

Description: Records related to planning, building and running PG&E's IT Operational Tools Technology including IT system management, Discovery and Service Modeling, Monitoring and Assurance, Situational Awareness, Automation and IT Service Management.

Examples:

- Architecture
- Change Management Documents
- Design Documentation
- IT Information Management Technology Standards
- Operations Manuals/Run Books/Process Documents
- Repository for IT Incident, Problem, Change, Asset, and Event Tickets
- Requirements
- Specifications and Testing Documents
- System Recover Process and Procedures

Record Category ID: ITS0900 | Record Category Name: Information Technology Records - IT Administration

Trigger Event: Superseded or end of calendar year, whichever is later

Retention Period: ACT+ 1 year

Description: Records related to maintaining PG&E's IT department, including records related to administration, business management, and project delivery methodology.

Examples:

- Business Plans
- Business Processes
- Performance metrics
- Policies
- Process Documents
- Standards

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: REG0200 | Record Category Name: Regulatory Records – CPUC - 25 Years

Trigger Event: Date of application or date proceeding initiated.

Retention Period: ACT+ 25 years

Description: Records related to PG&E's official regulatory filings and submissions with the CPUC. This category does not cover filings and submissions specifically included in Regulatory Records - CPUC Permanent (REG0210).

Examples:

- Applications
- Briefs
- Comments
- Complaints
- CPUC Decisions
- CPUC Ruling
- Data Requests / Responses
- Declarations
- Hearing Exhibits
- Letters to CPUC
- Notices
- Petitions
- PHC Statements
- Pleadings
- Protests
- Regulatory Models
- Reply
- Reports
- Testimonies
- Transcripts
- Workpapers

Record Category ID: REG0210 | Record Category Name: Regulatory Records - CPUC - Permanent

Trigger Event: Date of application or date proceeding initiated.

Retention Period: Life of Company

Description: Records related to the following PG&E official regulatory filings and submissions with the CPUC: 1) Certificate of Public Convenience and Necessity (CPCN) - Authority to Provide Service, 2) Hazardous Substance Mechanism (A.92-05-003), 3) Major Purchases/Sales of Facilities (e.g., Section 851), 4) Organizational Changes (e.g., Holding Company, Bankruptcy), 5) Tax OII (OII 24), 6) Regulatory Accounting Document (RAD) and 7) Advice Letters and Tariffs.

Examples:

- Advice Letters
- Certificate of Public Convenience and Necessity (CPCN)—Authority to Provide Service
- Hazardous Substance Mechanism (A.92-05-003)
- Major Purchases/Sales of Facilities (e.g., Section 851)
- Organizational Changes (e.g., Holding Company, Bankruptcy)
- Regulatory Accounting Document (RAD)
- Tariffs
- Tax OII (OII 24)

Record Category ID: REG0220 | Record Category Name: Regulatory Records - CAISO

Trigger Event: Date of submittal

Retention Period: ACT+ 25 years

Description: Records related to PG&E's submissions with CAISO (e.g. Stakeholder Comments).

Examples:

- All Regulatory Documents Submitted to CAISO
- Stakeholder Comments

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: REG0230 | Record Category Name: Regulatory Records - CEC

Trigger Event: Date of submittal

Retention Period: ACT+ 25 years

Description: Records related to PG&E's official regulatory filings and submissions to the CEC.

Examples:

All Regulatory Documents Submitted to CEC

Record Category ID: REG0240 | Record Category Name: Regulatory Records - FERC

Trigger Event: Date of submittal

Retention Period: ACT+ 5 years

Description: Reports to Federal and State regulatory commissions including annual financial, operating, and stastical reports.

Examples:

All Regulatory Documents Submitted to FERC

Cost of service filings (i.e., transmission owner tariff, wholesale distribution tariff rate cases)

Electric Quarterly Report (including FERC forms)

FERC-580: Interrogatory on Fuel and Energy Purchase Prices

FERC-730: Report of Transmission Investment Activity

FERC-920: Electric Quarterly Report

Other FERC Cases and Related Documents

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Record Category ID: REG0300 | Record Category Name: Rate Sheets & Schedule Records - CPUC

Trigger Event: Superseded, and when the schedule or agreement is no longer in effect

Retention Period: Life of Company

Description: Records related to the calculations and establishment of rates for billing gas and electric customers. Includes gas and electric rate schedules, preliminary statements, rules and forms and advice letters that are filed with CPUC.

Examples:

Advice Letters

CPUC – Filed Gas and Electric Tariffs

Disposition Letters

Tariffs

Record Category ID: REG0310 | Record Category Name: Rate Sheets & Schedule Records - FERC

Trigger Event: Superseded, and when the schedule or agreement is no longer in effect

Retention Period: ACT+ 6 years

Description: Rate Schedules: General files of published rate sheets and schedules of utility service, including schedules suspended or superseded.

Examples:

Rate Schedules

Service Agreements

Tariffs

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: OPS0340 | Record Category Name: Permits - Temporary - Transportation

Trigger Event: Expired

Retention Period: ACT+ 1 year

Description: Records related to all types of temporary permits, plans and registrations related to PG&E's transportation and aviation operations.

Examples:

Daily Operating Permits

Record Category ID: SER0100 | Record Category Name: Transportation & Aviation Services Records - Aviation Maintenance

Trigger Event: End of ownership (until sold and transferred) or discontinuation of the use of the asset

Retention Period: ACT+ 2 years

Description: Records related to the maintenance of PG&E's air fleet.

Examples:

Aircraft Registration(s)

Air-worthiness Certificates

Fuel Reports

Maintenance Logs and Reports

Parts Certifications

Parts Tracking Information

Repair Logs and Reports

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Record Category ID: SER0200 | Record Category Name: Transportation & Aviation Services Records - Aviation Operations

Trigger Event: End of calendar year

Retention Period: ACT+ 6 years

Description: Records related to the operation of PG&E's air fleet.

Examples:

Flight Logs

Flight Operation Reports

Pilot Schedules

Record Category ID: SER0300 | Record Category Name: Exposure Monitoring Records

Trigger Event: Termination of employment

Retention Period: ACT+ 30 years

Description: Records related to monitoring employee exposure to possible environmental hazards.

Examples:

Employee Exposure Documents

Employee Medical Files

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

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Record Category ID: SER0400 | Record Category Name: Environmental Incidents & Enforcement Action Records

Trigger Event: Resolution of action by agency/outside 3rd party

Retention Period: ACT+ 50 years

Description: Records related to planning, managing and reporting on environmental enforcement incidents and actions involving legal, federal, state or local agencies.

Examples:

- Attorney Work Products
- Case Management Information
- Claim Files
- Complaints
- Dispute Files
- Final Settlements
- Judgments
- Legal Hold Orders
- Litigation Files
- Notifications and Final Reports
- Settlement Files
- Subpoenas
- Voluntary Agreements

Record Category ID: SER0450 | Record Category Name: Environmental Investigation and Remediation Project Records

Trigger Event: Creation

Retention Period: ACT+ 50 years

Description: Records related to the management, documentation and reporting on PG&E's environmental remediation activities at PG&E owned, operating or leased property sites and facilities. Includes records documenting all aspects of the removal of pollution or contaminants from environmental media such as soil, groundwater, sediment, or surface water.

Examples:

- Cost documentation/spend information related to each phase of the investigation/remediation activity
- Property Correspondence
- Site Remediation Work Plans and Reports

Record Category ID: SER0500 | Record Category Name: Environmental Waste Management and Monitoring Records - Air

Trigger Event: End of calendar year or when superseded, whichever is later

Retention Period: ACT+ 50 years

Description: Records related to managing and monitoring all aspects of air quality at PG&E facilities and areas of operation. Includes records related to monitoring, inspecting and testing for elements impacting air quality, including dust, vapors, and greenhouse gases. Does not include employee medical files or medical surveillance information - see Exposure Monitoring Records. Does not include asbestos related information - see Environmental Waste Management and Monitoring Records - Asbestos.

Examples:

- Air Monitoring Results
- Continuing Monitoring System Records (CMS), Including Performance Evaluations
- Sampling Results and Reports
- Survey Records
- Test Reports and Test Results
- Waste Shipment Records

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: SER0510 | Record Category Name: Environmental Waste Management and Monitoring Records - Asbestos

Trigger Event: Life of facility **Retention Period:** ACT+ 50 years

Description: Records related to managing and monitoring asbestos-related activities at PG&E facilities and areas of operation. Does not include employee medical files or medical surveillance information - see Exposure Monitoring Records.

Examples:

- Materials Analyses
- Monitoring Records
- Sampling Records
- Survey Records
- Waste Shipment Records

Record Category ID: SER0520 | Record Category Name: Environmental Waste Management and Monitoring Records - Hazardous Waste

Trigger Event: Life of facility **Retention Period:** ACT+ 50 years

Description: Records related to managing and monitoring all aspects of hazardous waste at PG&E facilities and areas of operation, not included elsewhere in this RRS. Includes records related to polychlorinated biphenyls (PCBs).

Examples:

- Annual/Biennial Reports
- Certificates (decontamination)
- Exception Reports
- Inspection Documents
- Maintenance Documents
- Manifests and Shipping papers
- Removal From Use Documents
- Sampling and Analysis Reports
- Spill and Cleanup Records
- Test Reports and Test Results
- Waste Logs

Record Category ID: SER0530 | Record Category Name: Environmental Waste Management and Monitoring Records - Water

Trigger Event: End of calendar year **Retention Period:** ACT+ 50 years

Description: Records related to managing and monitoring all aspects of water quality at PG&E facilities and areas of operation. Includes records related to monitoring, inspecting and testing for elements impacting drinking water, storm water, and waste water.

Examples:

- Annual/Biennial Reports
- Exception Reports
- Inspection Documents
- Maintenance Documents
- Monitoring Records, Including Calibrations and Measurements
- Sampling and Analysis Reports
- Surveys
- Test Reports and Test Results

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: SER0600 | Record Category Name: Facility Construction and Transaction Records - Corporate

Trigger Event: Duration of property ownership or lease, or on expiration of all obligations, whichever is later

Retention Period: ACT+ 6 years

Description: Records related to the build, setup and legal management of PG&E owned or leased real estate and facilities that are NOT associated to electric or gas operations assets.

Examples:

- As-Built Drawings
- Construction plans and blueprints
- Deeds of Title/Ownership
- Facility Licenses and Building Permits
- Lease Agreements and Amendments
- Project Authorizations, Estimates and Business Cases

Record Category ID: SER0700 | Record Category Name: Facility Maintenance Records

Trigger Event: End of calendar year

Retention Period: ACT+ 6 years

Description: Records related to managing and maintaining PG&E owned or leased real estate and facilities that are NOT associated to electric or gas operations assets.

Examples:

- Building Maintenance Documents (all types)
- Inspection Reports (all types)
- Operating Licenses and Permits (all equipment types)
- Repair Documents (all types)
- Test Reports (all equipment types)

Record Category ID: SER0800 | Record Category Name: Transportation & Aviation Services Records - Driver Qualifications

Trigger Event: Termination of employment

Retention Period: ACT+ 6 years

Description: Records related to the activities and performance of PG&E vehicle fleet drivers.

Examples:

- Citations
- Driver Permits and Licenses
- Medical Certifications
- Proficiency Records

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: SER0900 | Record Category Name: Transportation & Aviation Services Records - Vehicle Maintenance

Trigger Event: End of ownership (until sold and transferred) or discontinuation of the use of the asset

Retention Period: ACT+ 2 years

Description: Records related to the operation and maintenance of PG&E's vehicle fleet.

Examples:

- Fuel Records
- Mileage Documents
- Vehicle Inspection Reports
- Vehicle Maintenance Logs and Reports
- Vehicle Request Documents
- Vehicle Titles and Registrations
- Vehicle Warranties

Record Category ID: SER1000 | Record Category Name: Health & Safety Monitoring Records

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to security and safety-related accident investigations and reports involving internal PG&E activities and personnel.

Examples:

- Accident Investigations and Reports
- Incident Reports
- OSHA Logs and Reports (including 300 log)
- Safety Inspections

Record Category ID: SER1100 | Record Category Name: Internal Support Records

Trigger Event: End of calendar year

Retention Period: ACT+ 1 year

Description: Records that are generated in the course of providing internal operational support related to audio visual services, meeting planning, printing and graphic design, editorial support, supplies and mail distribution.

Examples:

- Audio/Visual Documents
- Housekeeping Documents
- Mail and Distribution Services Documents
- Meeting Planning Documents
- Vending Services Documents

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: SER1200 | Record Category Name: Land Management Records - Ownership (Land Acquisition, Land Rights)

Trigger Event: Duration of property ownership or lease **Retention Period:** ACT+ 6 years

Description: Records related to the acquisition and management of PG&E's land rights for any and all of PG&E's line of business. Includes records for the acquisition and management of PG&E's ownership, property use agreements, rights of way, and access, including records related to the right to perform utility services on specific properties (as required by federal, state, or county) joint use contracts, pole hanging attachments agreements, leases of private or public property and acquisitions.

Examples:

- Acquisition (active) Files
- Agreements - Land Rights
- Agreements, Contracts Included in Contracts and Agreement Records - Corporate
- Conveyances Out - Land Rights
- Correspondence Supporting the Acquisition
- Deeds
- Drawings
- Easement Information
- Easements - Land Rights
- Facilities Information
- Fee Ownership - Land Rights
- Final Orders of Condemnation - Land Rights
- General Transfer of Assets
- Land Acquisitions & Conveyances
- Land Negotiation Documents
- License or Permit Applications and Requests
- Licenses - Land Rights
- Maps
- Master Agreements
- Permits - Land Rights
- Photographs & Supporting Documents
- Street Vacation Resolutions - Land Rights
- Supporting Documents - Land Rights

Record Category ID: SER1210 | Record Category Name: Land Management Records - Establishment of Ownership (Land Surveying & Enginee

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Trigger Event: End of project **Retention Period:** ACT+ 6 years

Description: Records related to the establishment of PG&E's land rights for any and all of PG&E's line of business.

Examples:

- Field and Land Surveys
- Field Notes
- Job/Project Files and all Supporting Documentation used to Establish Land Rights

Record Category ID: SER1220 | Record Category Name: Land Management Records - Natural Resource Management

Trigger Event: End of calendar year **Retention Period:** ACT+ 6 years

Description: Records related to PG&E's forest management, vegetation management and access road maintenance activities.

Examples:

- Access Repair Work Orders
- Access Road Files
- Corporate (Non Utility) Maintenance Records
- Timber Management Plans and Binders
- Timber Sales Documentation
- Vegetation management documentation
- Vegetation Removal Work Orders

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: SER1300 | Record Category Name: Office Administration Records

Trigger Event: End of calendar year

Retention Period: ACT+ 1 year

Description: Records related to on-going administrative support, operations or daily administration of an individual department or line of business.

Examples:

Budget Documents

Calendars

Points of Contact Lists

Record Category ID: SER1400 | Record Category Name: Permits - Permanent - Corporate

Trigger Event: Expired

Retention Period: Life of Company

Description: Records related to all types of permanent permits, plans and registrations related to business operations. Does not include temporary permits such as daily operating permits.

Examples:

Consent Orders

Encroachment Permits

Permits Related to Environmental Activities

Pressure Vessel Permits

Record Category ID: SER1410 | Record Category Name: Permits - Permanent - Electric T&D

Trigger Event: Expired

Retention Period: Life of Company

Description: Records related to all types of permanent permits, plans and registrations related to electric T&D operations. Does not include temporary permits such as daily operating permits.

Examples:

Consent Orders

Permits Related to Environmental Activities

Record Category ID: SER1420 | Record Category Name: Permits - Permanent - Gas

Trigger Event: Expired

Retention Period: Life of Company

Description: Records related to all types of permanent permits, plans and registrations related to gas utility operations. Does not include temporary permits such as daily operating permits.

Examples:

Consent Orders

Permits Related to Environmental Activities

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: SER1500 | Record Category Name: Policies, Procedures & Standards - Environment, Health & Safety

Trigger Event: Superseded

Retention Period: Life of Company

Description: Records related to planning and developing policies, procedures and standards related to environment, health and safety of PGE personnel and facilities.

Examples:

All environment, health and safety related policies, procedures, standards

Record Category ID: SER1600 | Record Category Name: Policies, Procedures, & Standards - Administrative

Trigger Event: Superseded

Retention Period: Superseded

Description: Records related to planning and developing standards, procedures and policies for the daily administration and operations of PG&E offices and departments. Does not include records included under Policies, Procedures & Standards - Environment, Health & Safety or Policies, Procedures & Standards - Operational & Technical.

Examples:

Advice Memos (e.g., accounting) and Decisions

Department Operations Policies

Line of Business Administrative Procedures

Record Category ID: SER1700 | Record Category Name: Project Management Records - Corporate (Non-Utility)

Trigger Event: End of project

Retention Period: ACT+ 10 years

Description: Records related to line of business project management activities associated to non-utility-related projects. Does not include projects associated with the engineering, design or construction of gas or electric utility assets.

Examples:

Advance Authorizations (AA)

Business Cases

Job Estimates

Project Administration Documents

Project Authorizations

Project Job Files

Project Management Databases

Project Scope Documents

Record Category ID: SER1800 | Record Category Name: Sourcing Records

Trigger Event: End of calendar year

Retention Period: ACT+ 6 years

Description: Records related to the purchase of goods and services for PG&E. Includes requests for proposals, bid evaluations and selections from issuance of an RFP or RFI by PG&E to purchase goods and services.

Examples:

Pricing Information (i.e., models)

Proposals

Purchase Orders

Receipts

Request for Proposals

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: SER1900 | Record Category Name: Supply Chain - Materials Management Records

Trigger Event: End of calendar year

Retention Period: ACT+ 6 years

Description: Records related to administering and operating PG&E's materials management activities. Does not include records related to material handling equipment - see Supply Chain - Material Handling Equipment Records.

Examples:

- Bills of Lading
- Chain of Custody Records
- Claims
- Cycle Counts and Adjustments
- Inventory (material) Disposition Reports
- Inventory Adjustments
- Lists of Materials Received and Issued
- Loss Reports
- Material Ledgers
- Shipping Notices

Record Category ID: SER1910 | Record Category Name: Supply Chain - Material Handling Equipment Records

Trigger Event: End of ownership (until sold and transferred) or discontinuation of the use of the equipment

Retention Period: ACT+ 2 years

Description: Records related to the maintenance and inspection of equipment related to PG&E's materials management activities.

Examples:

- Inspection Reports
- Maintenance Logs and Reports
- Operating Permits
- Warranties

Record Category ID: SER1920 | Record Category Name: Supply Chain - Supplier Quality Records

Trigger Event: Life of Asset

Retention Period: ACT+ 10 years

Description: Records related to the planning, administration and management of PG&E's supplier quality program.

Examples:

- Material Inspection Reports
- Material Test Reports
- Supplier Contract Work Authorizations
- Supplier Invoices

Record Category ID: SER1930 | Record Category Name: Supply Chain - Supplier Diversity Records

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to the planning, administration and management of PG&E's supplier diversity program as it relates to the inclusion of minority, woman, service-disabled veteran, or other diverse business enterprises (DBEs) in the supply chain.

Examples:

- List(s) of DBE Approved Suppliers
- Supplier Diversity Annual Reports and Supporting Information

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Record Category ID: SER2100 | Record Category Name: Work Orders & Maintenance Records - Corporate (Non Utility)

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to the daily maintenance and operations of non-utility corporate (non-utility) personnel, facilities, sites, equipment or support structures.

Examples:

Non-Utility Work Order Requests

Non-Utility Work Order Testing Information

Non-Utility Work Order Verification Information

Non-Utility Work Orders

Record Category ID: SER2200 | Record Category Name: Transportation Operations - Daily Vehicle Inspections

Trigger Event: End of Month

Retention Period: ACT+ 90 Days

Description: Records related to daily vehicle inspections detailing a consistent self-check of vehicle condidition

Strategic Planning & Business Development - Record Categories

Record Category ID: PLN0100 | Record Category Name: Business Development Records

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to planning to attract new customers and penetrate existing markets.

Examples:

- Approved Business Plans
- Business and Competitive Intelligence Data
- Business Development Budgets
- Confidentiality Agreements
- Planning Documents
- Proposal Templates
- Research Data

Record Category ID: PLN0200 | Record Category Name: Business Partnership Records

Trigger Event: End of partnership

Retention Period: ACT+ 10 years

Description: Records related to managing PG&E partnerships.

Examples:

- Joint Interest Files
- Partnership Documents
- Partnership Due Diligence Information

Record Category ID: PLN0300 | Record Category Name: Finance & Resource Management Records

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to planning, defining, implementing and managing financial, investment and resource strategies.

Examples:

- Benchmarking Reports
- Continuous Improvement Governance Guidelines
- Financial Forecasting and Project Information
- Forecast Reviews
- Governance and Sanctioning Documents
- Keys to Success Reports
- Performance Management Governance Guidelines
- Work & Resource Plans

Record Category ID: PLN0400 | Record Category Name: Finance & Resource Planning Records

Trigger Event: End of calendar year

Retention Period: ACT+ 3 years

Description: Records related to planning, defining, implementing and managing PG&E investment strategies.

Examples:

- Bonds and Certificates
- Investment Analyses and Allocations
- Investment Lists
- Investment Planning and Transactions
- Performance and Return Analyses
- Portfolio Inventory
- Purchase and Sale Documents

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Strategic Planning & Business Development - Record Categories

Record Category ID: PLN0500 | Record Category Name: Merger & Acquisition Records - Completed

Trigger Event: Resolution of activity

Retention Period: Life of company

Description: Records related to planning, directing, and managing PG&E's acquisitions and divestitures.

Examples:

- Acquisition Inventories
- Confidentiality Agreements
- Due Diligence Information
- M&A Plans

Record Category ID: PLN0600 | Record Category Name: Merger & Acquisition Records - Discontinued

Trigger Event: End of calendar year

Retention Period: ACT+ 5 years

Description: Records related to discontinued mergers, acquisition and divestiture activities.

Examples:

- Discontinued Merger and Acquisition Confidentiality Agreements
- Discontinued Merger and Acquisition Due Diligence Information
- Discontinued Merger and Acquisition Inventories

Record Category ID: PLN0700 | Record Category Name: Strategic Planning Records - Corporate

Trigger Event: Superseded

Retention Period: Life of Company

Description: Records related to documenting PG&E's corporate strategic plans and corporate strategy planning activities.

Examples:

- Annual Operating Strategic Plans (S1s)
- Corporate Strategic Framework
- Organizational Designs

Record Category ID: PLN0705 | Record Category Name: Strategic Planning Records - Integrated Planning

Trigger Event: Superseded

Retention Period: ACT+ 5 years

Description: Records related to documenting PG&E's integrated planning activities as they relate to how each LOB operationalizes PG&E's corporate strategy.

Examples:

- Business Area Integrated Strategic Plans (S2s)
- Growth Forecasts
- S-2 Budget Letters
- S-2 Final Presentations
- S-2 Planning Guidelines
- S-2 Prioritization Material

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

Revision Notes

Where? Entire Document

What Changed? Vital records and comments fields removed. ACT+ added to retention periods with trigger events. New category for Electric.

Retention Period: The length of time a record must be kept, after which the record can be dispositioned (destroyed or preserved as a historical document).

Trigger Event: An occurrence, either calendar or event based (for example: end of year, termination date, end of matter, end of project), that begins the retention period.

PART 1: OVERVIEW

a) Best Practice: 10 **b) Status:** Complete

Minimize Uncontrolled Natural Gas Emissions Training

Training to ensure that personnel know how to use company emergency procedures which describe the actions staff shall take to prevent, minimize and/or stop the uncontrolled release of natural gas from the gas system or storage facility. 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 General Rate Case (GRC) and/or Collective Bargaining Unit (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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E performs regular maintenance on its system and has procedures in place to minimize and support the prevention of uncontrolled release of methane. PG&E's Gas Emergency Preparedness department manages a training program consisting of three Gas Emergency Response Plan (GERP) trainings that are updated and assigned to designated employees to complete on an annual basis. The trainings supporting PG&E's GERP include the following:

- Gas-9121 GERP Awareness;
- Gas-9122 GERP Gas Operations Response Training, Virtual and Recorded Virtual Trainings; and
- Gas-9123 GERP Emergency Center Staff, Instructor Led Training.

In addition to performing GERP training, PG&E relies on performance metrics to measure the effectiveness of PG&E's actions to prevent, minimize and/or stop the uncontrolled release of natural gas from the gas system. Two key performance metrics are "emergency response time" and "shut-in the gas time". Among benchmarked utilities PG&E's emergency response time performance is top decile. In 2017, PG&E's average response time was 20.4 minutes and it responded within 60 minutes 99.6% of the time. In addition to responding as quickly as possible, PG&E monitors and pushes for continual improvement in the time it takes to shut-in the gas following an unplanned release. In 2017, the shut-in the gas time for gas service-related events was 45.16 minutes, which was an improvement of 0.6 minutes over 2016 performance. For events involving gas mains, the shut-in the gas time in 2017 was 103.78 minutes which was 0.65 minutes better than 2016 performance. In 2018, the target for services in 44.03 minutes with a median time of 35 minutes, and the mains target is 101.19 minutes with a median of 87 minutes.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E plans to utilize its existing process as mentioned in question a) above as it adheres with the BP.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

PG&E's training programs for gas emergency response incorporate requirements to maintain compliance with DOT 49 CFR 192, California State Senate Bills 887 and 745, and CPUC General Order 112-F. This BP does not have incremental requirements beyond those in regulation.

e) What technology is required to implement the best practice and why?

No new technology is required.

f) Will work require additional personnel and/or contract support? If so, please provide details.
No additional resources are required.

g) What changes to existing operations are required? How will those changes be implemented?
No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
No new procedures are required

i) Timeline for implementation (Milestones):
Compliance with this BP is complete.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
No costs are associated with this BP.

k) Identify any cost benefits from this BP, when cost estimates are known:
See question j) above.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
See question j) above.

m) Anticipated Emissions Reductions from this BP:
No emissions reductions are anticipated from this BP.

2015 Baseline Emissions affected, where known: N/A
Please see the response under part m) above.

n) Calculation Methodology: N/A
Please see the response under part m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:

None.
c) Research or Studies: None.
d) Other: None.

PART 1: OVERVIEW

a) Best Practice: 11 **b) Status:** Complete

Methane Emissions Minimization Policies Training

Ensure that training programs 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.

PART 2: BEST PRACTICE DETAILS

a) Historic work: All technical training follows an industry best practice development and delivery methodology. The training programs that include information about the release of natural gas currently educate PG&E's employees on why it is necessary to minimize the uncontrolled release of natural gas, thus minimizing methane emissions**.**

b) Alternative Proposal to BP or exemption?
None.

c) Proposed Plan:
Continue to build education of employees on why it is necessary to minimize methane emissions into new curriculum.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?
No other regulations overlap.

e) What technology is required to implement the best practice and why?
Various technologies and media are used to train PG&E's employees – Instructor Led Training, computer based training, virtual learning etc. There are no new requirements for technology to implement this BP in addition to what PG&E isare already using.

f) Will work require additional personnel and/or contract support? If so, please provide details.
No additional resources are required.

g) What changes to existing operations are required? How will those changes be implemented?
No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
No new procedures are required**.**

i) Timeline for implementation (Milestones):
Compliance with this BP is complete.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
No costs are associated with this BP.

k) Identify any cost benefits from this BP, when cost estimates are known:
See question j) above.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
See question j) above.

m) Anticipated Emissions Reductions from this BP:
No emissions reductions are anticipated from this BP.

2015 Baseline Emissions affected, where known:
Please see the response under part m) above.

n) Calculation Methodology:
Please see the response under part m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
The training programs implementing this best practice will communicate PG&E's safety-related performance metrics with respect to minimizing methane emissions. At this time, the two safety-related performance metrics are "emergency response" time and "shut-in the gas" time.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
None.

d) Other:
None.

PART 1: OVERVIEW

a) Best Practice: 12 **b) Status:** Complete

Knowledge Continuity Training Programs

Knowledge Continuity (Transfer) Training Programs to ensure 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.

PART 2: BEST PRACTICE DETAILS

a) Historic work: PG&E has a knowledge transfer program in place.

b) Alternative Proposal to BP or exemption?
None.

c) Proposed Plan: PG&E plans to utilize its existing process as mentioned in question a) above as it adheres with the BP.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?
No other regulations overlap.

e) What technology is required to implement the best practice and why?
No technology is required.

f) Will work require additional personnel and/or contract support? If so, please provide details.
No additional resources are required.

g) What changes to existing operations are required? How will those changes be implemented?
No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
No new procedures are required**.**

i) Timeline for implementation (Milestones):
Compliance with this BP is complete.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
No costs are associated with this BP.

k) Identify any cost benefits from this BP, when cost estimates are known:
See question j) above.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
See question j) above.

m) Anticipated Emissions Reductions from this BP:
No emissions reductions are anticipated from this BP.

2015 Baseline Emissions affected, where known:
See response to question m) above.

n) Calculation Methodology:
See response to question m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
Any new methane emissions reduction best practices shared through knowledge continuity training programs will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
None.

d) Other:
None.

PART 1: OVERVIEW

a) Best Practice: 13 **b) Status:** Complete

Performance Focused Training Programs

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.

PART 2: BEST PRACTICE DETAILS

a) Historic work: All technical training follows an industry standard for development and delivery. All of PG&E'stechnical field training includes knowledge and skill based curriculum, practical hands on practice and reinforcement time, knowledge and skill assessments aligned with OQ's.

b) Alternative Proposal to BP or exemption?
None.

c) Proposed Plan:
PG&E plans to utilize its existing process as mentioned in question a) above as it adheres with the BP and supports the continuous practice of knowledge and skill based testing and assessments.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?
No other regulations overlap.

e) What technology is required to implement the best practice and why?
No technology is required.

f) Will work require additional personnel and/or contract support? If so, please provide details.
No additional resources are required.

g) What changes to existing operations are required? How will those changes be implemented?
No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
No new procedures are required**.**

i) Timeline for implementation (Milestones):
Compliance with this BP is complete.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
No costs are associated with this BP.

k) Identify any cost benefits from this BP, when cost estimates are known:
See question j) above.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
See question j) above.

m) Anticipated Emissions Reductions from this BP:
No emissions reductions are anticipated from this BP.

2015 Baseline Emissions affected, where known:
Please see the response under part m) above.

n) Calculation Methodology:
Please see the response under part m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
None.

d) Other:
None.

PART 1: OVERVIEW

a) Best Practice: 14 **b) Status:** Complete

Formal Job Classifications

Create new formal job classifications for apprentices, journeyman, specialists, etc., where needed to address new methane emissions minimization and leak abatement best practices, and filed as part of the Compliance Plan filing, to be approved by the CPUC, in consultation with CARB.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E currently utilizes a talent requisition site to provide guidance on hiring both union and non-union employees. This allows for leaders to work with Human Resources and Labor Relations (as applicable) to create job openings, define the classification of the job, and look for candidates with existing qualifications and/or prior experience. This process also provides leaders with the support needed to make updates to existing classifications.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E will utilize its historic work as described above in response a) to address any new classifications that are required. Current job classifications adequately address necessary skills and training for employees whose work can affect methane emissions and leak abatement. At this time, PG&E does not anticipate any new classifications to be created for methane emissions minimization or leak abatement in 2018 and 2019.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

None.

e) What technology is required to implement the best practice and why?

No new technology is required.

f) Will work require additional personnel and/or contract support? If so, please provide details.

No additional resources are required.

g) What changes to existing operations are required? How will those changes be implemented?

None. PG&E's existing process is set up to incorporate changes to existing job classifications as needed.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.

None. PG&E's existing procedures can be utilized.

i) Timeline for implementation (Milestones):

Not applicable. PG&E is adhering to this BP.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:

Not applicable.

k) Identify any cost benefits from this BP, when cost estimates are known:
Not applicable.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
Not applicable.

m) Anticipated Emissions Reductions from this BP:
Not applicable.

2015 Baseline Emissions affected, where known:
Not applicable.

n) Calculation Methodology:
Not applicable.

o) Additional Comments:
None.

p) Overlap with Safety:
Should job classifications be updated to address new methane emissions minimization and leak abatement best practices, PG&E will provide, as needed, training and qualifying exams that support performing new activities safely.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
None.

d) Other:
None.

PART 1: OVERVIEW

a) Best Practice: 15 **b) Status:** Pilot

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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E surveys approximately 75% of its Gas Distribution system using Picarro technology and the remainder is surveyed by foot.[9] Gas Distribution moved to a three-year leak survey cycle starting January 1, 2018.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E plans to utilize its existing process as mentioned in question a) above as it adheres with the BP.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

No other regulations overlap.

e) What technology is required to implement the best practice and why?

PG&E will continue to use the Picarro technology. Beginning in Q2 2018, PG&E will also use Digital Catalyst as a way to identify and document leaks in the field within 30-45 seconds of discovery compared to the current state wherein it requires approximately 24 hours to identify potential hazards.

f) Will work require additional personnel and/or contract support? If so, please provide details.

Yes – An estimated increase of 40 additional contractors will be needed for conducting leak surveys, bringing the total number of leak survey contractors to 80 for 2018. PG&E does not anticipate hiring additional employees for this work.

g) What changes to existing operations are required? How will those changes be implemented?

No changes to current operations are anticipated.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.

No new procedures need to be developed.

i) Timeline for implementation (Milestones):

The three year leak survey process began January 1, 2018.

[9] PG&E's 2017 GRC, 15-01-009, Exhibit 3, Chapter 6C, page 13.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
The 3 year leak survey cycle – including estimated costs - was reviewed and approved by the Commission as part of PG&E's 2017 GRC.[10] As PG&E described in the 2017 GRC, the expanded use of the Picarro Surveyor will find more leaks, and the benefits of using the technology from a safety and methane emissions perspective outweigh not using the technology, despite the higher leak repair cost that comes with finding more leaks.

k) Identify any cost benefits from this BP, when cost estimates are known:
The abatement of 0.129 Bcf/y as calculated in m) will lead to cost saving of $ 2,644k/y corresponding to the WACOG of the 2018 Illustrative Gas Supply Portfolio: $2.05/therm.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
It is anticipated that this BP overlaps with BP 1, 9, 16, and 17, as these BPs also relate to leak survey scheduling. There will be coordination required to maintain records and to schedule the various surveys happening on different frequencies, as discussed in each of those four BP templates.

m) Anticipated Emissions Reductions from this BP:
Changing to a three-year leak survey cycle from a four-year cycle is estimated to reduce natural gas emissions from the distribution system by around 20% or roughly 0.129Bcf (using 2015 baseline). The savings will be fully realized in Year 4 of the new cycle after steady state has been reached. See attached documents for calculation details (BP15_ATCH01). The impact on the emissions data can be tracked in Appendix 4 of the annual leak report for Leak Abatement OIR.

2015 Baseline Emissions affected, where known:
In 2015, emissions from leaks on distribution pipelines is 626 MMscf. As noted above, emissions are forecasted to reduce by roughly 20% from 2015 baseline levels based on moving to a three-year leak survey cycle.

n) Calculation Methodology:
See attached documents for calculation details (BP15_ATCH01). The attached spreadsheet (BP15_ATCH02) includes calculations on 2015 data. One of the main assumptions made is that the Grade 3 leak backlog remains constant.

o) Additional Comments:
None.

p) Overlap with Safety:
Conducting more frequent leak survey may improve the safety of PG&E'sgas system by identifying leaks sooner than they otherwise would have been found, especially hazardous or "Grade 1" leaks. Grade 1 leaks require immediate repair and once identified, PG&E personnel stand-by a Grade 1 leak until the repair crew arrives.

SUPPLEMENTAL INFORMATION

[10] PG&E's 2017 GRC, 15-01-009, Exhibit 3, Chapter 6C, page 22.

a) Technology: None.
b) Changes to Operations: None.
c) Research or Studies: None.
d) Other: None.

Leak Survey Transition from a 4 year to a 3 year plan: Leak Emissions in the Distribution System

Abstract
This document provides a method to estimate the reduction in emissions from distribution pipeline leaks when moving from a 4-year to a 3-year leak survey frequency.

Theory
In order to transition from surveying on a four-year interval to a three-year interval we must first make several assumptions. First we assume that leaks appear in the same linear manner in all original four different survey areas. Additionally we assume that when combining the original four different areas into the three new survey areas, that they are surveyed from oldest to newest. For example, during the first year of transition, we survey all the territory surveyed four years ago and one third of the territory surveyed three years ago as opposed to surveying one third of each old territory. Finally, 1996 GRI/EPA emission factors were used to estimate emissions from leaks.

Figure 1: From four years to three years

In order to change fourths to thirds one must multiply by four-thirds. Therefore, one must take four thirds of a year in the old survey to create one year in the new survey. The next three figures show the area surveyed each year during the transition from a four-year leak survey to a three-year leak survey.

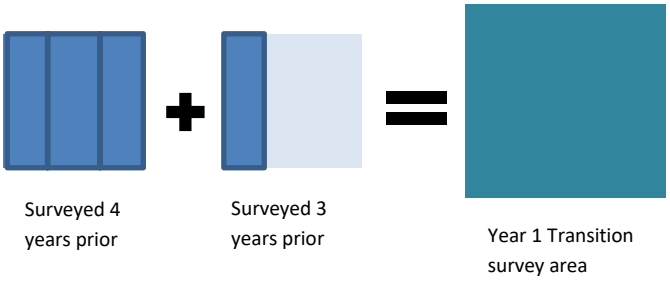


Figure 2: Area Surveyed during Year 1 of Transition

During the first year of transition, the entire four-year old territory is surveyed as well as one-third of the three-year old territory. When looking at the emissions of the area surveyed for this year, the following equation is used, where *E* represents the original emissions from leaks found during a year in the four year cycle.

$$_1 = \ _{-4} + \frac{3}{4}\left(\frac{1}{3}\right) \ _{-3}$$

The one-third tracks from having one-third of the area surveyed and the three-fourths come from the assumption that leaks appear linearly over time. Therefore, if the last time an area was surveyed was three years ago we expect to find three-fourths as many leaks as the area last surveyed four years ago. This equation can also be used to calculate the number of leaks by replacing emissions with number of leaks found.

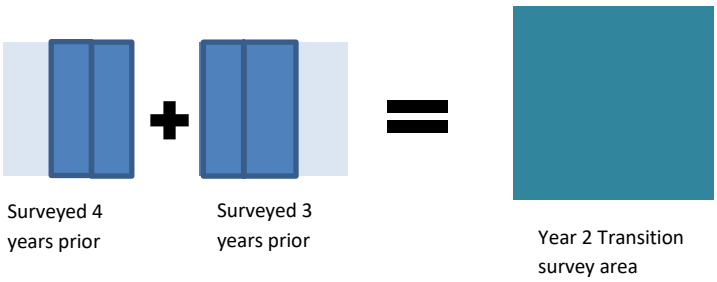


Figure 3: Area Surveyed during Year 2 of Transition

In the second year of transition, we have moved forward a year causing the remaining two-thirds of area from the first transition year to shift back to being 4 years ago once again. Here four-thirds are summed together again to create the new survey area.

$$_2 = \frac{2}{3} \ _{-4} + \frac{3}{4}\left(\frac{2}{3}\right) \ _{-3}$$

Once again we can see the spatial components denoted by thirds and the time components denoted by fourths and are colored blue.

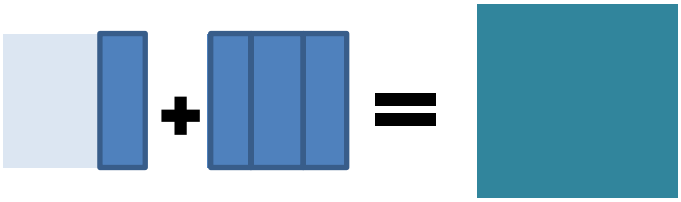


Figure 4: Area Surveyed during Year 3 of Transition

In the final year of transition, the majority of area was last surveyed 3 years ago while one-fourths of the area was last surveyed four years ago.

$$_{3} = \left(\frac{1}{3}\right) \ _{-4} + \frac{3}{4} \ _{-3}$$

Following the transition years, the number of leaks that are found in surveyed area every year is the same as the number originally found when surveying the system every four years. This is because you are surveying four-thirds of the original area at three-fourths of the original time.

When calculating system-wide emissions, the emissions from the areas not surveyed that year must also be included. The following figures and equations show the three transition year emissions for the area not being surveyed at the time.

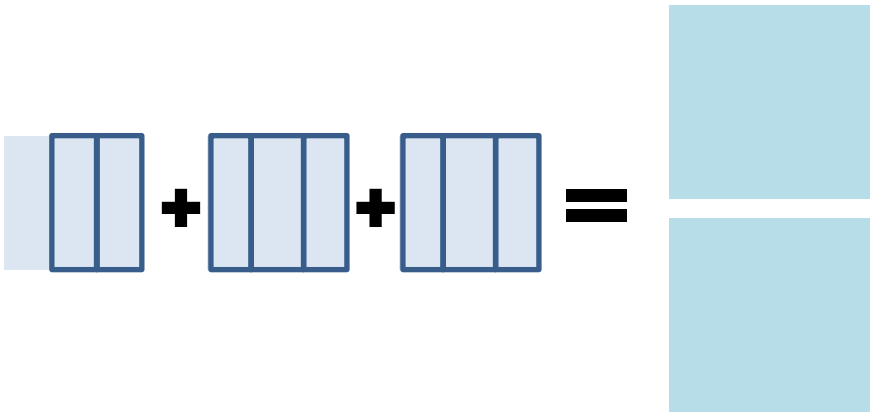


Figure 5: Area Not Surveyed during Year 1 Transition

In Figure 5, the natural gas contributions from the area not surveyed are shown. The area from which they come from is two thirds of the service territory. Here, we use the assumption that leaks appear in a linear fashion over time. In addition, to prevent underestimating[1], we assume each leak opens on the first of the year and remains open for the entire year (8760 hours). The number of leaks found in one year of a four year survey is denoted as C, for count, in the following equations. EF stands for emission

[1] It has been shown that, when leaks appear linearly, this approach exactly compensate for the leaks that appeared during the year of survey after the time the surveyor went to their locations.

factor, which varies based on material and coating. The count for each material is matched with its appropriate emission factor for as many different materials that are leaking in the system.

$$1 \qquad = \frac{1}{4}\left(\quad\right)8760 + \frac{2}{4}\left(\quad\right)8760 + \frac{3}{4}\left(\frac{2}{3}\right)\left(\quad\right)8760$$

Here the area last surveyed three years ago is multiplied by two-thirds to represent that the remainder three-year old territory was surveyed. The linear time factor appears in front of all the terms and is colored blue.

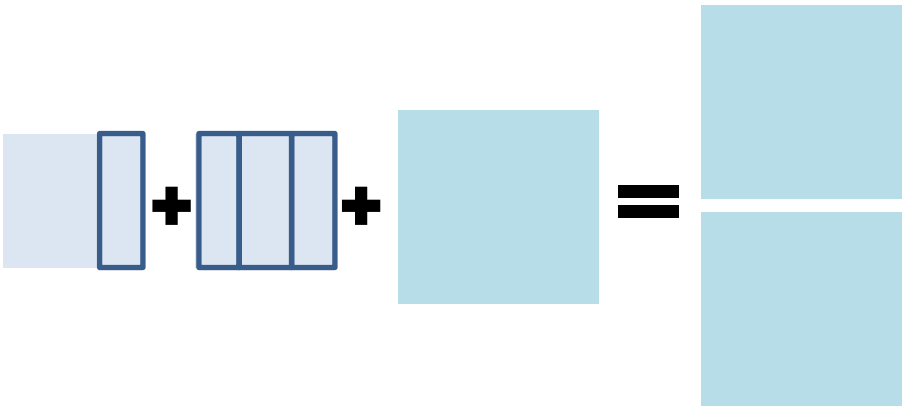


Figure 6: Area Not Surveyed Year 2 Transition

In the second year of transition a third of the system has been surveyed in the previous year, this changes the equation.

$$2 \qquad = \frac{1}{4}\left(\frac{4}{3}\right)\left(\quad\right)8760 + \frac{2}{4}\left(\quad\right)8760 + \frac{3}{4}\left(\frac{1}{3}\right)\left(\quad\right)8760$$

The first term has a factor related to the time an area was last surveyed: one-fourth, as well as another factor for area surveyed which is four-thirds of the original size. When these two are multiplied together the result is one third. The sum of the numeric multipliers is 13/12 as opposed to 15/12 from the first year of transition. The smaller numeric multiplier shows that the number of leaks in the system should be decreasing.

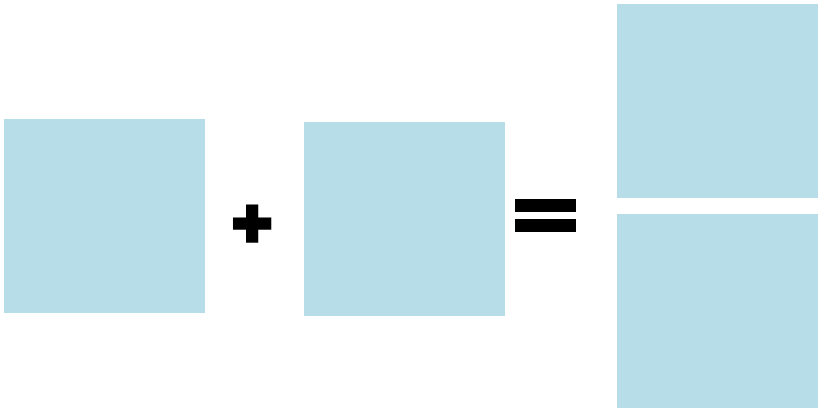


Figure 7: Area Not Surveyed Year 3 Transition

In the final transition year, there have already been two surveys on a third of the system. This final transition year for the area not surveyed is in fact no longer a transition period but the new steady state. In other words, from this year onward, the equation used to calculate from emissions unsurveyed areas will be similar. The equation for the steady state is as follows:

$$_{3} = \frac{1}{4}\left(\frac{4}{3}\right)\ (\quad)8760 + \frac{2}{4}\left(\frac{4}{3}\right)\ (\quad)8760$$

This can then be easily simplified to.

$$_{3} = \frac{1}{3}\ (\quad)8760 + \frac{2}{3}\ (\quad)8760$$

The sum of the numeric multipliers in the steady state equation is one, showing a further reduction in the number of open leaks in the service territory.

Theoretical change in number of leaks

To summarize the discussion above, we can plot the following chart (Figure 8) to show changes in number of leaks moving from four-year to three-year leak survey. In chart below, 100% refers to number of leaks found yearly from 1/4th of PG&E territory after it has not been surveyed for 4 years.

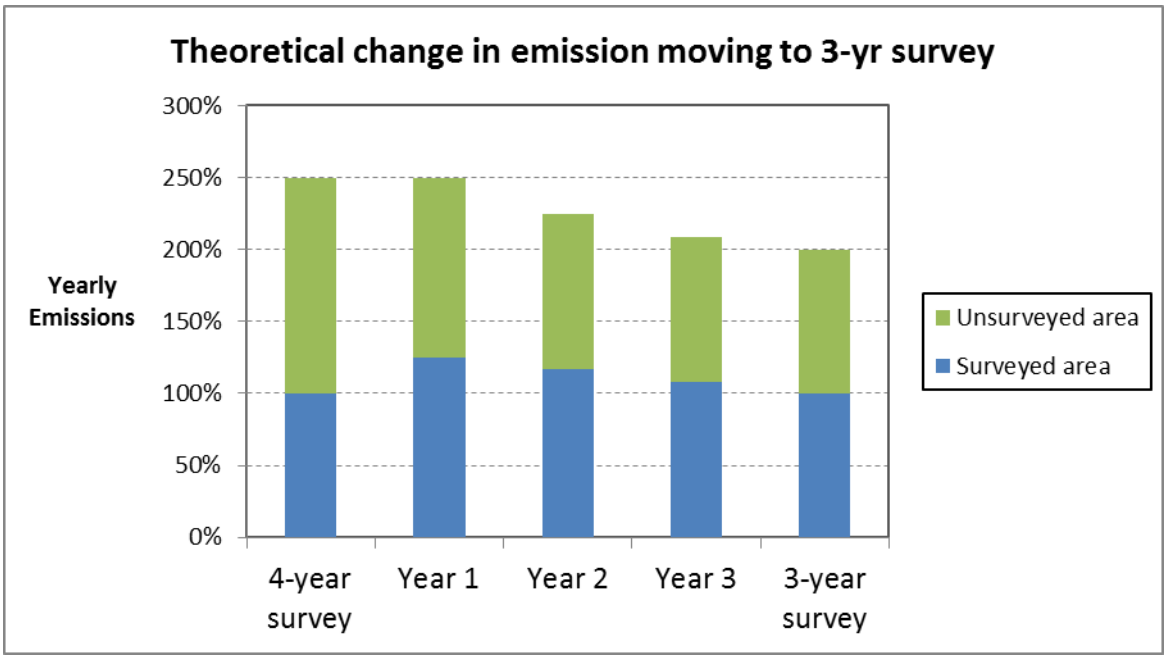


Figure 8. Theoretical change in number of leaks found

As seen above, theoretically, number of leaks should decrease from 250% to 200% (**20% reduction**). The number of leaks found in surveyed areas increase initially as a larger area is surveyed but it goes back to 100% (or the original value) because the higher survey frequency leaves less time for leaks to develop. On the other hand, leaks from areas not surveyed decrease by one-third after the transition. This makes sense since the un-surveyed areas are smaller in three-year leak survey and are surveyed more frequently.

In the section below we apply the algorithms to the baseline 2015 distribution leaks data.

Applying algorithms to 2015 data

The application of the general theory above yields the results in Table 1. Leaks found in 2015 were used to compute the baseline emission for 4-year survey. We assume that the areas to be surveyed are similar to the area surveyed in 2015. Also, we make the same assumption for un-surveyed areas, that they are similar to the area surveyed in 2015. An additional assumption was that leaks appear linearly over time. Please note that emission factors from 1996 GRI/EPA study were used in the calculation. There is around a **20% decrease** in natural gas emissions when shifting from a four-year leak survey to a three-year leak survey when examining this base calculation.

Emissions from leaks found through leak survey (Mscf)

		Emissions from Surveyed areas (Mcf)	Emissions from Unsurveyed areas (Mcf)	Total Emissions in [Mcf]	% change from baseline
	4-yr survey (Year 0)	171,204	387,813	559,017	**0%**
Transition	**Year 1**	214,005	323,177	537,182	**-4%**
	Year 2	199,738	280,087	479,825	**-14%**
	Year 3	185,471	258,542	444,013	**-21%**
	3-yr survey (Year 4)	171,204	258,542	429,746	**-23%**

Reduction (Mcf)	129,271

Table 1: Emissions in Billions of cubic feet per year

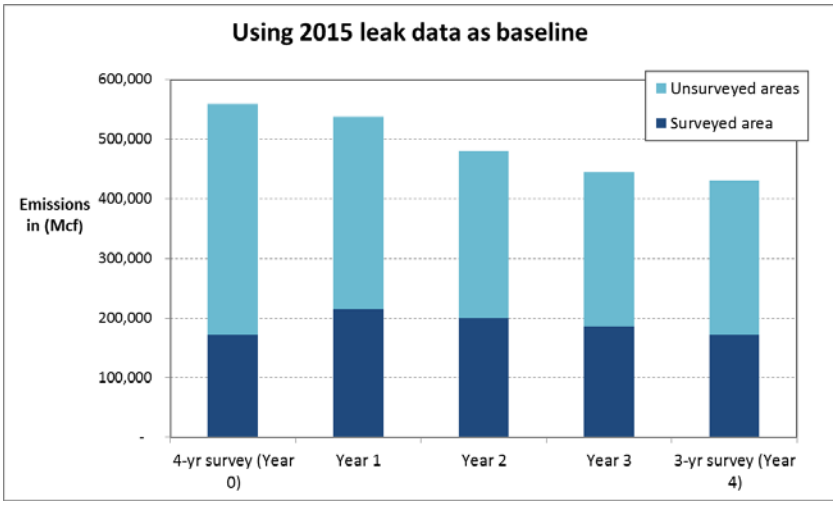


Figure 9: Emissions for Transition from a 4-year to a 3-year leak survey frequency

The trend observed in emissions is similar to the theoretical changes in the number of leaks as seen in Figure 8. The emissions from surveyed areas stay flat while the reduction is in emissions from areas that

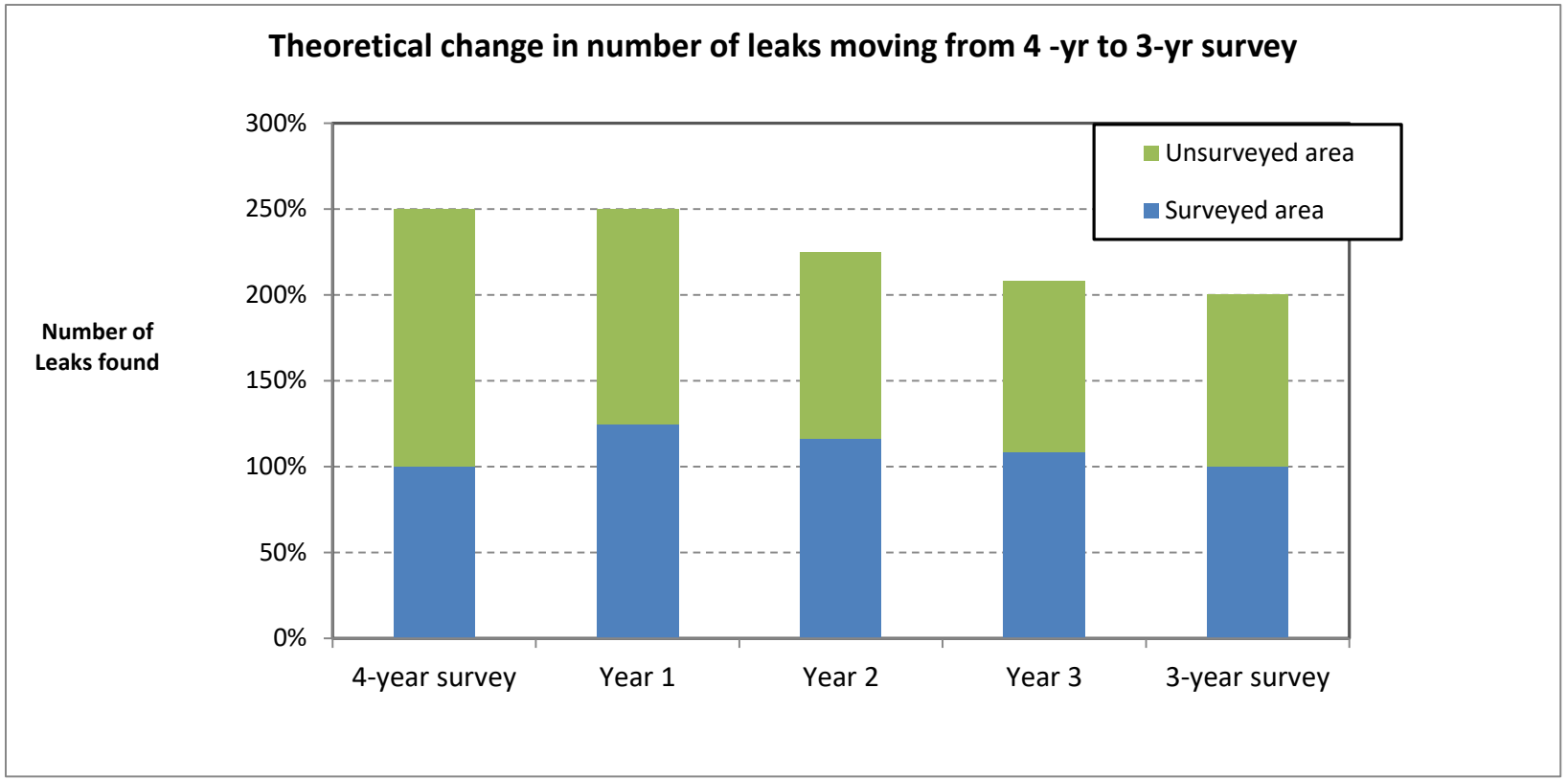
are not surveyed in the particular year. In subsequent years (Year 5 onwards), the emissions will be similar to Year 4 in the model.

Conclusion

Changing to a three-year leak survey cycle will reduce natural gas emissions from the distribution system by around 20% or roughly 0.129 Bcf (based on 2015 numbers as baseline).

If we make the assumption that PG&E territory is divided into 4 similar areas with same rate of leak occurrence:
In table below, 100% is emissions from 1/4th of PG&E territory after it has not been surveyed for 4 years.

		Number of leaks in surveyed area	Number of leaks in unsurveyed areas	Cumulative reduction from baseline 4-year survey
	4-year survey	100%	150%	0%
Transition	**Year 1**	125%	125%	0%
	Year 2	117%	108%	-10%
	Year 3	108%	100%	-17%
	3-year survey	100%	100%	-20%



Assumptions for the model:

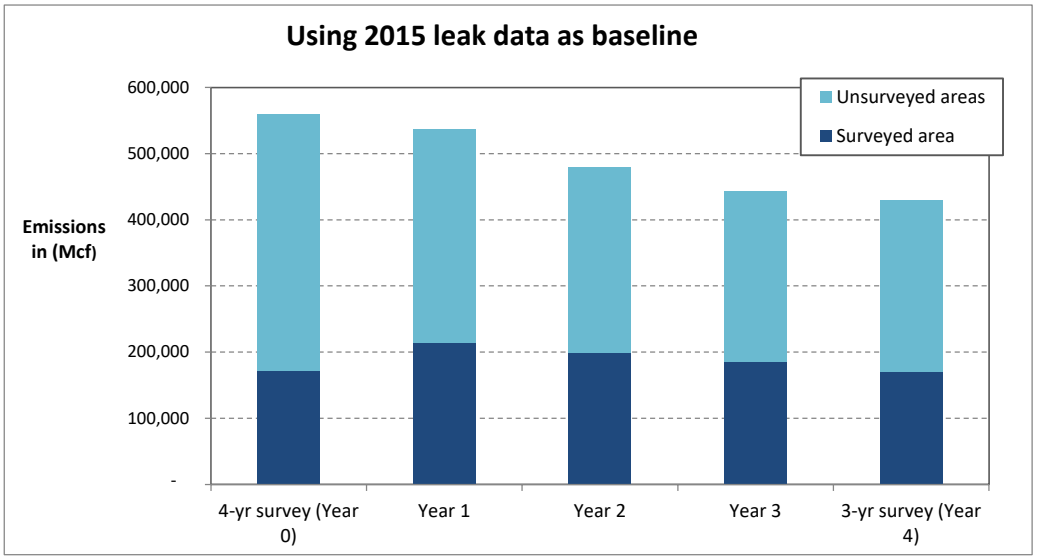
The areas/ survey territories are similar (no variation in number of leaks)

We exclude unprotected steel from the leaks since they are already surveyed on a 3-year basis

Emissions from leaks found through leak survey (Mscf)

		Emissions from Surveyed areas (Mcf)	Emissions from Unsurveyed areas (Mcf)	Total Emissions in [Mcf]	% change from baseline	Comments	Formula for Surveyed areas	Formula for Unsurveyed areas
	4-yr survey (Year 0)	171,204	387,813	559,017	**0%**		E4	1.5 C
Transition	**Year 1**	214,005	323,177	537,182	**-4%**		E4 + (3/4)*(1/3)E3	(1/4)C + (2/4)C + (3/4)*(2/3)C
	Year 2	199,738	280,087	479,825	**-14%**		(2/3)E4 + (3/4)*(2/3)E3	(1/4)*(4/3)C + (2/4)C + (3/4)(1/3)C
	Year 3	185,471	258,542	444,013	**-21%**		(1/3)E4 + (3/4)E3	(1/4)*(4/3)C + (2/4)*(4/3)C
	3-yr survey (Year 4)	171,204	258,542	429,746	**-23%**		Same as above, steady state reached	Same as above, steady state reached

Reduction (Mcf)	129,271



2015 Baseline

2016 Emissions (5-year leak survey frequency, Excluding MSA leaks)

	2015 Emissions from Leaks found Pre-2015 (Mscf)	2015 Emissions from Leaks Detected from 2015 Survey (Mscf)	2015 Estimated Emissions from Unknown Leaks (Mscf)	Total (Mscf)
Total	67,573	171,204	387,813	626,590

PART 1: OVERVIEW

a) Best Practice: 16 **b) Status:** Pilot

Special Leak Surveys

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

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E's Distribution Integrity Management Program (DIMP) currently identifies special leak surveys from the results of its risk assessment cycle. The target of the survey is job installations within high risk areas on which a systematic issue exists but leak rates do not justify a replacement. DIMP also identifies special leak surveys outside its risk assessment cycle for investigations and special assessments.

Transmission assets are leak surveyed twice every year, per guidance of GO 112-F. Special leak surveys are identified beyond the requirements of GO 112-F for investigations and special assessments as required.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

To meet the scope of BP16, PG&E proposes conducting additional leak survey on select vintage pipes on distribution assets. The proposed plan is to perform a pilot on targeted special leak survey on distribution Aldyl-A plastic and steel pipes. The material focus of the special leak survey is pre-1940 steel and pre-1975 Aldyl-A vintages, shown to have higher leak rates. The surveys only target pipe segments of this vintage with leak history. PG&E will assess the results of the pilot to determine whether to continue with surveys on vintage pipe.

In addition, PG&E is exploring the idea of risk-based leak survey in collaboration with Picarro. The purpose of this research is to develop and test the use of combined data, such as observed leak rate from previous surveys, risk score from DIMP analysis, methane indications from higher frequency mobile monitoring, and predictive analytics to optimize leak surveys. See attachment for details.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

This proposal, specific to leak emission abatement, does not overlap with any existing regulations.

e) What technology is required to implement the best practice and why?

There is no special technology needed to implement this best practice.

f) Will work require additional personnel and/or contract support? If so, please provide details.
The resource requirement for this work is estimated at two contract full time employees for conducting the leak survey and three fulltime employees to conduct repairs per month for the duration of the survey.

g) What changes to existing operations are required? How will those changes be implemented?
This additional special leak survey proposal does not require changes to existing operations.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
This additional special leak survey proposal does not require any new procedures or modifications to existing procedures.

i) Timeline for implementation (Milestones):
The implementation of this pilot survey is planned for April through October 2018.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
The cost estimate of the special leak survey consists of two components: (1) leak survey costs; and (2) costs associated with leak repair or pipe replacement. It is assumed that any below-ground services with a leak will be replaced instead of being repaired. This assumption is based on current service replacement criteria which apply to the specific material that this special leak survey targets. Total cost is roughly $1.6 million per year.

The methane emissions reduction was calculated using the forecasted number of leaks and the emission factors from the 1996 GRI/EPA study. Total savings is around 2.08 MMcf per year. More details of this calculation and the assumptions made can be found in the supplemental section below.

Dividing the total yearly cost by the yearly emissions savings, a cost-effectiveness number of $796/Mcf methane is obtained. In subsequent years, the number of leaks found is expected to decrease due to the increased frequency in leak survey. Consequently, the cost-effectiveness number will worsen (higher) as the fixed cost from leak survey account for a bigger percentage of the cost.

k) Identify any cost benefits from this BP, when cost estimates are known:
The abatement of 2.08 MMscf/y as calculated in m) will lead to cost saving of $ 43k/y corresponding to the WACOG of the 2018 Illustrative Gas Supply Portfolio: $2.05/therm.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
No. One third of the pipes identified for this special leak survey and thus corresponding emission reductions was estimated to overlap with the benefits from BP 15 (Gas Distribution Leak survey), based on the current leak survey cycle, and excluded from calculations. See supplemental section below for more details.

m) Anticipated Emissions Reductions from this BP:
The anticipated methane emissions reduction for the first year is 2.08 MMcf. The amount of reduction is expected to decrease in subsequent years due to lower number of leaks found because of the increased frequency.

2015 Baseline Emissions affected, where known:
Total emissions from leaks on distribution pipelines in 2015 was 626 MMscf. In that year, the potential savings from this BP was embedded in the emissions from the leaks in the un-surveyed areas.

n) Calculation Methodology:
The 1996 GRI/EPA emission factors were used to calculate the overall emissions of the leaks for year 2018. Please see the supplemental section below for more details.

Assumptions:
1. Assume only Grade 1 and 2 leaks are repaired.
2. Assume that methane emissions reduction is only for the year of interest.
3. Assume leaks are found throughout the year and will be repaired quickly (multiply savings by a factor of 0.5).
4. Assume that 1/3 of services will be surveyed by Compliance leak survey (this is accounted for in the number of services to survey).
5. Assume that the ratio of Aldyl-A to steel pipe leaks is similar to the ratio of Aldyl-A to steel pipe surveyed.

o) Additional Comments:
None.

p) Overlap with Safety:
The additional special leak survey could result in identifying potential hazards sooner than they might be otherwise, potentially providing a safety benefit.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
None.

d) Other:
See the attached spreadsheet for the 1996 emission factors and calculations referenced above (BP16_ATCH01).

Assumptions:

1. Assume Ratio of Aldyl-a and steel pipe leaks is equal to the ratio of Aldyl-a to steel services surveyed
2. Assume 1/3 of services will be surveyed by compliance leak survey (this is accounted for in the number of services to survey)
3. Assume only Grade 1 and 2 leaks will be repaired
4. Assume emission reduction is only for the year of interest
5. Assume leaks appear linearly over time and are found throughout the year (multiply savings by a factor of 1/2)
6. 1996 GRI/EPA emission factors are used for the emissions calculations

Material	Miles of Main (2018)	Number of Services (2018)
Aldyl-A Pre-1975	132	10,560
Steel Pre 1940	99	7,920
Total	231	18,480

	# leaks			Cost ($)	CH4 Emissions reduction (scf)	
	Overall	Pre-1975 Aldyl-A	Pre-1940 Steel	Overall	Pre-1975 Aldyl-A	Pre-1940 Steel
Main	29	17	12	$ 344,208	903,657	351,120
Service	147	84	63	$ 1,313,094	136,130	689,850
Total	176	176		$ 1,657,303		2,080,757

Emission Reduction Unit cost ($/Mcf)	**$ 796**

Forecast

	2018	2019	2020	2021	2022
Services Counts	18,480	18,480	18,480	18,480	18,480

Volumes are approximations based on available information at the time and may slightly from year to year.

In terms of mileage, there are roughly 200 miles of pipes to survey

Leak Survey Cost:

Units	Unit Cost	Cost of leak survey
18,480 services	$18.23/service	$336,890

Leak Repair Breakdown:

Units	Grade			
MAT Code	**1**	**2**	**3**	**Grand Total**
FIH	9	70	288	367
FIG	8	21	31	60
FIP	0	0	0	0
50G	27	37	60	124
50M	0	4	6	10
Grand Total	**44**	**132**	**385**	**561**

Assumptions:

1. We use 1996 EPA/GRI emission factors for the abatement calculations
2. Use Plastic Main and Plastic Service emission factors for Pre-1975 Aldyl A leaks
3. Use Unprotected Steel Main and Unprotected Steel Service emission factors for Steel Pre-1940 leaks

	1996 US EPA/ GRI Report		2015 WSU Report		2016 GTI Report	
	[scf/hour]	Sample Size	[scf/hour]*	Sample Size	[scf/hour]	Sample Size
Unprotected Steel Main	6.45	20	2.58	74	2.93	23
Protected Steel Main	2.55	17	4.05	31	NA	NA
Plastic Main	12.45	6	1.11	23	3.37	16
Protected Steel Service	1.15	24	0.44	12	NA	NA
Unprotected Steel Service	2.50	13	1.11	19	1.54	18
Plastic Service	0.37	4	0.44	38	1.92	21

*The 2015 WSU Report used the units of grams methane/min, which can be multiplied by 3.35 to convert to scf natural gas/hour

			Unit Cost					Total Unit Cost	Total Cost
		Units	Labor	Materials	Contract	Other	Overhead Costs		
	Leak survey	**18480**						$ 18.23	$ 336,890
FIH	**AG service repair**	**79**	$ 79	$ 0	$ 14	$ 2	$ 192	$ 287.05	$ 22,677
FIG	**Main repair**	**29**	$ 2,188	$ 19	$ 1,831	$ 268	$ 5,649	$ 9,955.10	$ 288,698
FIP	**BG service repair**	**0**	$ 967	$ 7	$ 577	$ 120	$ 2,466	$ 4,137.22	$ -
50G	**Service replacement, simple**	**64**	$ 3,179	$ 63	$ 3,700	$ 49	$ 6,991	$ 14,876.90	$ 952,122
50M	**Service replacement, complex**	**4**	$ 3,235	$ 64	$ 3,766	$ 50	$ 7,115	$ 14,229.02	$ 56,916
									$ 1,657,303

Number of services to survey

For steel, the proposal, this includes approximately 150 miles of pipe, not scheduled for replacement in 2018. For Aldyl-A, this includes approximately 200 miles, not scheduled for replacement in 2018.

Note that the mileage could vary from year to year based new methodology for risk assessment, priority values, and completed work.

350 miles * 0.66 = 231 miles

231 miles X 80 services/mile = **+18,480 services**

Factor of .66 is used as an approximation for overlapping areas with compliance survey.

Note: Volumes are estimates and exact numbers will require additional analysis.

PART 1: OVERVIEW

a) Best Practice: 17 **b) Status:** Pilot with R&D

Enhanced Methane Detection

Utilities shall utilize enhanced methane detection practices (e.g. mobile methane detection and/or aerial leak detection) including gas speciation technologies.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E has been using advanced mobile technology for compliance leak surveys for three years. It has been at the forefront of this development through its partnership with Picarro. PG&E has also been using Differential Absorption Lidar (DIAL) LiDAR aerial surveys for a portion of its Transmission system (Lassen). Finally, PG&E has initiated several R&D projects to improve leak detection technologies, including gas speciation to differentiate between biomethane and pipeline gas.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E plans to continue to use advanced mobile and aerial technologies and will engage additional R&D efforts to improve these technologies. It will also continue the use of highly sensitive mobile methane and ethane detection technology (Picarro Surveyor), and develop new solutions through R&D efforts, including:

- Piloting fixed wing DIAL (Differential Absorption LiDAR) aerial surveys;
- Developing and Testing light UAV mounted leak detection technologies;
- Exploring Optical Imaging Technologies; and
- Piloting the use of high sensitivity handheld devices for leak surveys.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

No other regulations overlap.

e) What technology is required to implement the best practice and why?

This BP uses and explores a broad range of technologies. Current work leverages Cavity Ring Down Spectroscopy (CRDS) high sensitivity for mobile survey and DIAL for airborne surveys. R&D and pilot activities will explore additional technologies. See supplemental sections for attachments.

f) Will work require additional personnel and/or contract support? If so, please provide details.

R&D and pilot projects are performed using contract support.

g) What changes to existing operations are required? How will those changes be implemented?

No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.

No new procedures are required**.**

i) Timeline for implementation (Milestones):

This BP is already implemented by PG&E which is a leader in the industry. R&D and piloted projects will be implemented based on test results to continuously improve performance.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure,

when costs estimates have been determined:
PG&E is using new technologies to implement this best practice. New technologies often provide benefits that evolve over time. Some of the projects described above are funded through research consortiums and their costs are shared with other utility companies. The average leverage ratio for the projects is 3.7 which mean PG&E is paying approximately a quarter of the research costs. This allows PG&E to keep R&D activities cost-effective. At this time, PG&E cannot quantify any cost-effectiveness or cost benefits related to the new technologies.

k) Identify any cost benefits from this BP, when cost estimates are known:
See question j) above.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
This BP mainly aims to increase effectiveness of surveys and to improve detection sensitivity to find more leaks more quickly. This BP contributes to the performance of other BPs (BP 15, BP 16 and BP 20).

m) Anticipated Emissions Reductions from this BP:
By allowing faster detection of a higher number of smaller leaks from the gas system, this BP leads to methane emission reductions that can be represented by the adjustment of leak based Emissions Factors for the utilities implementing this BP. Field measurements will be performed to support the new Emissions Factors and calculate the abatement.

2015 Baseline Emissions affected, where known:
Please see the response under part m) above.

n) Calculation Methodology:
Please see the response under part m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
This BP provides leak detection tools that improve safety and contribute to methane emission reduction.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
See attachments

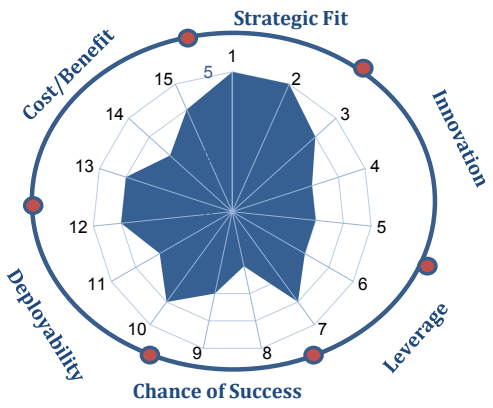
- Evaluation of Optical Gas Imaging technologies for detection of distribution system leaks (NYSEARCH) (BP17_ATCH01).
- Field test of the new generation of handheld devices based on NASA/JPL high sensitivity technology (BP17_ATCH02).

- Integration of NASA/JPL high sensitivity technology methane-ethane detector on small Unmanned Aerial Systems for leak detection and localization (NYSEARCH) (BP17_ATCH03).
- Pilot of fixed wing LiDAR-DIAL (Differential Absorption LiDAR) for Transmission System leak detection (BP17_ATCH04).

d) Other:
None.

Multispectral Gas Imaging Technologies (Multi-Sensor Scientific)

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	Gas imaging cameras are a tool that allows for detection, identification of leaks, and potentially quantification of leak flow rate. The technology has mainly been used in the production sector to facilitate fast detection and pinpointing of leaks. However, conventional gas imaging cameras have difficulties finding underground leaks because of low thermal contrast between the gas plume and the ground. This NYSEARCH project will evaluate the use of a unique gas imaging camera that does not rely on thermal contrast to find non-hazardous/smaller leaks in the distribution systems. The detection limit of this technology to detect underground leaks and its ability to quantify leak flow rate will be evaluated in the field on actual leaks.The deliverable is a report describing the test results. The expected completion date is the end of 2018.	5
	How does it fit in our overall strategy and rank among our priorities?	This project will benefit PG&E's effort to detect and locate leaks and to meet requirements of new regulations such as CARB Oil and Gas Rule for underground storage facility and address Best Practices recommendations as part of SB1371 for natural gas leak abatement.	5
Innovation	What is the state of the art?	State-of-the-art gas imaging cameras typically produce black and white images of the field-of-view and are not well suited to detect underground leaks because of the low thermal contrast between the ground and the gas plume. In addition, gas leak quantification using cameras is still a largely unproven concept and is generally more suited for larger leaks (FLIR, a leading brand in this field, offers this but does not guarantee high accuracy, Rebellion received funding from ARPA-E to develop a technology able to quantify leak flow rates).	4
	What is the existing solution at PG&E?	PG&E uses pump-based infrared instruments (DP-IR) for leak surveys. PG&E has a couple of Heath's EyeCGas gas imaging cameras and have used them for leak detection at gas storage facilities. PG&E also contracts leak detection and quantification work at storage and compressor facilities to Montrose who uses FLIR GF-series cameras. We are starting another project to test OGI technologies on large facilities through PRCI.	3
	How does the team compare to competition?	Multi-Sensor Scientific is a startup developing breakthrough technology in the gas imaging industry. They claim that their technology functions differently from conventional cameras and do not rely on thermal contrast for detection. The team has relatively limited experience in the gas industry but they have shown great enthusiasm to start a project with utilities.	3
Leverage	How does the project leverage previous work?	This project will leverage a past project (in 2004) that NYSEARCH has done to evaluate early versions of gas imaging technologies. NYSEARCH can also leverage the recent protocols they have used to evaluate other leak survey technologies.	3
	What are the opportunities of co-financing?	The total cost of this 1-year project is $134,420. The approximate cost for PG&E is $20,680. for a leverage ratio of 6.4	4
Chance of Success	What are the risks for failure?	There is considerable amount of risk that the technology will not reliably detect small underground leaks. It is well researched that gas imaging cameras are currently not very sensitive to small leaks making them unsuitable for distribution leak survey.	2
	What are the requirements for deployment at PG&E?	The prototype instrument will have to be tested alongside existing leak survey instruments and have intrinsically safe design.	3
Deployability	How will the solution be used?	The technology can eventually be used to detect and locate leaks at facilities or even at distribution systems (if this project is succesful). Having the leak quantification ability would accelerate the adoption of this device as it helps to fulfill the best practices recommended by SB 1371.	4
	What additional delays have to be accounted for the full deployment?	The technology has to improve to the point that it is as sensitive as currently used handheld leak survey equipment.	3
	How does it synchronize with existing actions?	This project synchronizes with our testing and development of multiple leak survey technologies such as the NASA JPL handheld sensor, Picarro surveyor, Ball Aerospace aerial leak survey and the work done with NYSEARCH about leak quantification using Schlieren technology.	4
Cost vs Benefits	Can we assess cost benefits of the solution?	The benefit of using gas imaging camera compared to conventional sniffers is faster leak detection and localization at facilities . Assuming the net increase in speed is 25%, the $18/service unit cost of routine leak survey (~$9M per year) can be brought down to $14/service (~$7M per year) . In addition, being able to quantify emissions from leaks will help tremendously with annual reporting and can potentially reduce contract costs.	4
	What will the on-going cost of the solution after deployment be?	Once deployed, gas imaging cameras will require maintenance and calibration just like current equipment.	3
	What is an acceptable cost target for PG&E?	$20.7k is an acceptable cost for PG&E considering the positive effect this may have in educating us about the advances in leak detection and quantification technologies.	4
		Total	**3.6**

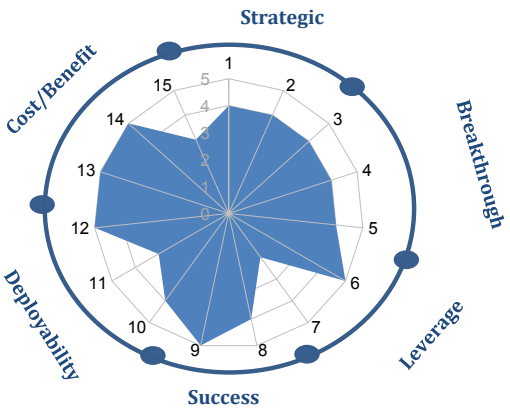


Project: **Field Testing of Miniature Ethane and Methane Sniffer**

	Key criteria for assessment	Comments	Score (0 5) 0 is bad 5 is excellent
Strategy	What issue(s) does it solve?	In the process of deployment of the technology develop through PRCI since 2014, this project plans to test a series of industrial prototypes of the sniffer developed by NASA/JPL and built by RKI, which is capable of measuring methane and ethane concentrations at a precision of 10 and 1 ppb respectively. This is a big improvement with respect to current instruments and bridges the gap in sensitivity with Picarro surveyor to enable faster localization of leaks. The lightweight sniffer can also be used on a UAV to survey hard-to-reach places and can potentially be used to localize and quantify leak size.	4
	How does it fit in our overall strategy and rank among our priorities?	This development complement efforts made in leak survey (e.g. Picarro) and are well aligned with new initiatives on the use of UAV (Unmanned Aerial Vehicles), and on methane leak measurements.	4
Innovation	What is the state of the art?	Through PRCI, JPL has successfully demonstrated a lightweight handheld methane detection sensor in 2014. A series of projects with UC Merced, PRCI and NYSEARCH are in progress to integrate the methane sensor on small and micro UAVs. JPL has been making progress with a commercialization partner, RKI Instruments Inc. The outcome of this effort is expected to be a state-of-the-art sniffer that can be used for both foot survey and UAV survey. To be noted that Picarro and ABB are also working on backpack ethane-methane detectors but the units are much heavier (~15 lbs) and more costly.	4
	What is the existing solution at PG&E?	Currently PG&E uses DP-IR as the methane detector for walking leak survey. The new sensor will allow faster walking surveys and provide better traceability with automated record of covered area and observed metahne emissions. The UAV mounted system will also open new applications especially for hard to access area s and for facilities.	4
	How does the team compare to competition?	RKI Instruments, the company selected by NASA JPL to industrialize the detector, has over twenty years of experience developing gas detection equipment. They have formed a partnership with RIken Keiki Co. Ltd., a Japanese company with a large market share ($220 million) in gas monitors worlwide. The expertise of the team combined with guidance from NASA Jet Propulsion Laboratory (JPL) will ensure that the eventual product meets a high standard of quality.	4
Leverage	How does the project leverage previous work?	The technology at the core of the project has been initially developed by JPL for Mars exploration and is currently in operation on the Curiosity rover. In addition, the project will leverage the work performed in 2014-2016 on the handheld device by PRCI. The project will also leverage another project that is perfromed with RKI to assist in the industrialization of the product and will have access to a series of 8 prototypes to be tested with the opportunity to provide feedback and take advantage of improvements.	5
	What are the opportunities of co-financing?	The cost of field test is estimated to $100,000 over a period of time of two years. SoCal Gas, Baltimore GAs and Eleectric Company and Engie are co-sponsoring the industrialization effort by committing to purchase prototype units . The work will be performed in cooperation with them to optimize experience in a variety of configurations.	2
Chance of Success	What are the risks for failure?	The handheld version of the detector has been tested in the field at PG&E in 2015. It has also been integrated in multiple UAS for leak detection flights. The most recent test was completed successfully in a mock-up neighborhood at PG&E in gusty conditions which demonstrates the robustness of the detector. The possibility of not succeeding is very low.	4
	What are the requirements for deployment at PG&E?	The tool is expected to be commercialized at the end of the project and ready for deployment.	5
Deployability	How will the solution be used?	The handheld version of the instrument can be used for walking leak survey and to follow up on Picarro indications just like how the DP-IR is being used currently.	4
	What additional delays have to be accounted for the full deployment?	Leak survey procedures will be adjusted to the new technology including leak grading and eventually leak quantification.	3
	How does it synchronize with existing actions?	This project is well synchronized with other efforts at NYSEARCH, and PRCI and the industrialization effort initiated with RKI.	5
Cost vs Benefits	Can we assess cost benefits of the solution?	The eventual cost of the handheld instrument is expected to be competitive with the DP-IR (~$11,000). IN addition, it provides higher level of sensitivity for a better follow-up leak search to Picarro's indications and faster leak pinpointing. The ethane function will reduce cost associated with sending samples to the lab for biogas determination.	5
	What will the on-going cost of the solution after deployment be?	There will be minor ongoing costs to maintain and calibrate the instruments.	5
	What is an acceptable cost target for PG&E?	N/A	3
		Total	4.1

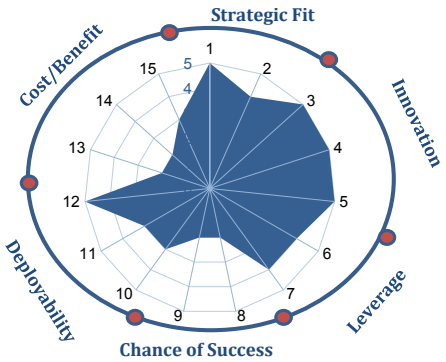
References:

L. Christensen, F Rongere " Mars Rover Technology for Leak Detection on Hazardous Liquid & Gas Pipelines" WRGC Tempe August 2015



Project: NYSEARCH Methane Sniffer Small Unmanned Aerial System (ms-sUAV)

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	Unmanned Aerial System (UAS) - or drone - technologies have made dramatic progress in the past few years driven by military applications. The technology is now being transferred to commercial applications with high expectations. FAA is preparing its rulemaking to authorize and regulate the use of small UAS for commercial applications. In preparation for that, PRCI and NYSEARCH have introduced projects to explore the use of UAS for gas utilities. One major application is leak detection for difficult-to-access areas: the plan is to use automated micro-UAS (lighter than 4.4 pounds) to detect and locate leaks along sections of pipelines that would be difficult to survey with road vehicles or by foot. The present project aims to develop a rotor craft micro-UAS for leak survey. It will be led by JPL for the gas detector and UC Merced for the UAS integration. It will build upon results obtained in the project approved on 2/28/2015 and being contracted now with UC Merced.	5
	How does it fit in our overall strategy and rank among our priorities?	PG&E and other gas operators are seeking for more effective ways to inspect their assets. UAS may complement aerial and ground surveys for more flexibility (for example: UAS are not subject to a minimum flying floor altitude), better reliability, lower cost, and better safety. The UAS targeted by the project will allow a fully automated flight that will detect and locate leaks in difficult to access terrains.	4
Innovation	What is the state of the art?	Currently, there is no use of micro-UAS to detect and locate leaks on pipeline systems. NASA JPL has successfully demonstrated in 2013 the deployment of its light methane detector on a micro-UAS to measure methane emissions from a larger source. The major challenge for leak detection on pipeline system is the very low flow rate emitted by the leaks, typically 0.5 to 10 cf/hour.	5
	What is the existing solution at PG&E?	PG&E does not use UAS today. The JPL methane detector has been adapted to its use as a handheld device in 2014 through a PRCI project. Leak surveys are performed by air using a LIDAR technology, by foot and by car using Picarro.	5
	How does the team compare to competition?	NASA/JPL has developed a detector that surpasses existing technologies in sensitivity (10 ppb) and miniaturization (250g). It is a perfect fit for a micro-UAS. The Mechatronic laboratory at UC Merced is led by a renowned professor in the field of UAS (YanQuan Cheng). It has two COA (Certificate of Authorization) areas already approved by the FAA for the field tests and has the ability to rapidly integrate automation systems at a low cost. NYSEARCH has a strong track record of developing deployable tools.	5
Leverage	How does the project leverage previous work?	This project will directly leverage the project currently contracted with UC Merced to lead to a fully operational prototype. JPL gives us access to their experience in measuring methane emissions using similar technology and partnering with UC Merced gives us access to YanQuan Chen's experience in the automation of small UAS.	4
	What are the opportunities of co-financing?	This project will result in a fully operational prototype demonstrated in field environment. Its cost will be $421k for the development of the leak detection UAS. PG&E is expected to fund $64k for a leverage ratio of 6.6.	4
Chance of Success	What are the risks for failure?	The project will develop and demonstrate the first operational leak detection micro-UAS. Automation will allow not only detection but also localization of leaks. Many issues have to be solved for a successful project. The team's complementary skill sets make the ambitious goal achievable. The work engaged with UC Merced prior to the project will help mitigate risks by providing a good analytical base to the optimization of the UAS.	2
	What are the requirements for deployment at PG&E?	The major limitations for the use of UAS at PG&E will be the regulations by FAA and potentially local restrictions. Training and safety procedures will also need to be developed and extensively tested.	2
Deployability	How will the solution be used?	The functional prototype will be used to specify a commercial product. A specific requirement is the possibility to mount the sensor on different platforms to provide the base of a broader range of tools for utilities.	3
	What additional delays have to be accounted for the full deployment?	Regulations must advance to allow deployment of UAS on commercial applications but the demonstration of the prototype will directly contribute to educate and form regulators' decisions about broadening the use of UAS applications for leak detection. A subsequent project by NYSEARCH co-funded by PHMSA will allow additional tests and comparison with eventual other solutions to provide a wider choice to utilities.	3
	How does it synchronize with existing actions?	This project is in line with our efforts in improving leak detection, especially the development with JPL of a light methane detector completed at the end of 2014. It aligns with projects performed with PRCI, PHMSA and UC Merced. It will be a critical step in influencing and taking advantage of the new regulations in preparation by the FAA.	5
Cost vs Benefits	Can we assess cost benefits of the solution?	The benefits of using UAS will depend on the applications that will be identified and authorized by the FAA. Real cost benefits are difficult to assess at this point.	2
	What will the on-going cost of the solution after deployment be?	On-going costs of the UAS will depend on applications and regulations. Targeted cost of the micro-UAS is within tens of thousands of dollars.	2
	What is an acceptable cost target for PG&E?	Current costs of aerial surveys are $6M/y, ground patrols for transmission lines $2M/y, leak surveys for distribution mains and services $13M/y (2014 - S2 planning). Micro-UAS may reduce costs for difficult to access areas and help in methane emission assessments.	3
		Total	**3.6**



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J Mallia "JPL Methane Detector and Control System: small UAS regulatory and technology assessment" March 2015
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North Central Texas Regional General Aviation and Heliport System Plan "Unmanned Aircarft Systems Report" December 2011
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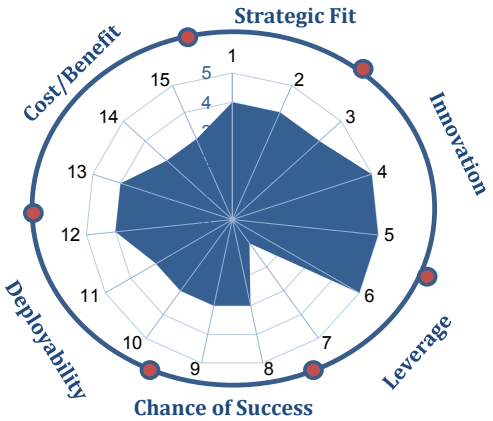
L. Christensen, YQ Chen Methane Sniffer Small Unmanned Aerial System (ms-sUAV) Proposal to NYSEARCH February 2015.

Project: Side by side pilot trial of Ball Aerospace and Lasen airborne Leak sensing equipment

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	In the past few years, Ball Aerospace has been working on a laser-based remote sensing equipment, Differential Absorption LIDAR (DIAL), which can be mounted on an aeroplane and used for aerial leak survey. The laser system sweeps the area below the aircraft and creates a heat map of methane plumes it detects to provides indications of the source location. Recently, considerable improvement has been made to the sensitivity of the sensing equipment and it was shown to detect leaks of size 50 cf/hour. Combined with its ability to be flown on aeroplanes, large swath width, high flight altitude, the system is a promising tool for cost-effective transmission pipeline leak survey. This project will perform side by side trial flights with LASEN to compare the effectiveness of the systems for transmission pipeline leak survey.	4
	How does it fit in our overall strategy and rank among our priorities?	This project is part of our broader effort in developing new technologies for leak survey such as the project with PRCI, NASA/JPLand UC Merced to develop UAV-based airborne leak detection system.	4
Innovation	What is the state of the art?	Currently, the Differential Absorption LIDAR is limited to deployment on helicopters such as the services provided by LASEN and another European company (ADLARES GmbH). Mounting the system on an aeroplane allows for better cost efficiency: the proposed system is the first one available on fix wing aircrafts. There is ongoing work to develop leak detection system on fixed wing UAVs for long flights but will need a few more years to come to fruition.	4
	What is the existing solution at PG&E?	PG&E uses LASEN for the semi-annual aerial transmission pipeline leak survey and the cost is $6M/yr. There is opportunity to reduce this cost by switching to an aeroplane based survey.	5
	How does the team compare to competition?	Ball Aerospace has been developing the DIAL system for fixed-wing aircraft through a PHMSA project in 2014-15. It has also been awarded by PHMSA for the adaptation of the system for the detection of distribution leaks.	5
Leverage	How does the project leverage previous work?	This project will directly leverage the development of the DIAL system on fixed-wing aircrafts being completed through a PHMSA grant.	5
	What are the opportunities of co-financing?	PG&E will reach out to SoCal Gas, Southwest Gas and other utilities for their interest in this project.	1
Chance of Success	What are the risks for failure?	The project will compare Ball Aerospace system with Lasen system. If successful, the new technology will be implemented for Transmission pipeline leak surveys.	3
	What are the requirements for deployment at PG&E?	The system will have to show that it is as effective as LASEN in detecting underground leaks. In addition, the system has to show it does not miss many leaks when compared with foot survey. Results recently obatined by Ball Aerospace in a previous field test in 2017 are very encouraging.	3
Deployability	How will the solution be used?	PG&E will either use Ball Aerospace as a service provider or purchase the equipment for our transmission pipeline leak survey. The system can also be used to detect locations of superemitters at our facilities for emission monitoring purposes.	3
	What additional delays have to be accounted for the full deployment?	The software of the system has to advance to meet the operational requirement of PG&E's Patrol team. Data from the aerial leak survey should be packaged in a format that is easily digestible by the leak survey team for quick follow up.	3
	How does it synchronize with existing actions?	This project is in line with our other efforts on improving leak detection, such as the UAV-based leak detection system and handheld ethane-methane detector.	4
Cost vs Benefits	Can we assess cost benefits of the solution?	The cost of using this equipment can be compared directly with the cost of service provided by LASEN which is $6M/yr. Additional benefit such as improved sensitivity and better software will provide a greater incentive to switch to Ball Aerospace. The $50k allocated for the pilot trial will provide useful data to evaluate effectiveness of Ball Aerospace's system and provide a path to adopting the technology in the future.	4
	What will the on-going cost of the solution after deployment be?	Depending on whether the system will be sold or provided as a service, the on-going costs may include the maintenance and training of personnel to operate the equipment.	3
	What is an acceptable cost target for PG&E?	The cost of the pilot trial will be roughly $50k. For reference, Current costs of aerial surveys are $6M/y, ground patrols for transmission lines $2M/y. $50k is an acceptable cost to do a pilot a technology with potential to substantially reduce the current cost.	3
		Total	**3.6**



PART 1: OVERVIEW

a) Best Practice: 18 **b) Status:** Pilot and R&D

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 the installation location.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E has used stationary Lower Explosive Limit (LEL) gas detectors in building Compressor Stations. PG&E has supported the development and testing of open path stationary methane detectors since 2013. Recent pilot projects account for four open path stationary methane detector units at underground storage facilities at McDonald Island and one unit at Los Medanos in collaboration with the Pipeline Research Council International (PRCI) and Environmental Defense Fund (EDF).

b) Alternative Proposal to BP or exemption?

Test of stationary leak detectors at a small number of facilities to test performance and maintenance cost and to optimize solution before broad deployment.

c) Proposed Plan:

The Oil & Gas regulation introduced by CARB in 2017 directs compressors and storage facilities operators to perform quarterly leak surveys, to repair leaks quickly after discovery and to install stationary ambient detectors at storage facilities. To comply with this regulation, PG&E proposes to test stationary leak detectors at a small number of facilities to evaluate performance and cost factors of different units before broadly deploying units across its territory. Refer to attachment entitled "Quantifying emissions from Transmission M&R stations". In addition, PG&E will continue to work with the industry to lower cost of sensors. For instance, PG&E is supporting a project with Operations Technology Development (OTD) to evaluate commercially available methane sensors for leak survey and continuous monitoring applications. See the supplemental section below for more details.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

Oil & Gas regulation introduced by CARB covers Compressor Stations and Gas Storage Facilities. The application of the BP to City Gates, and Metering & Regulating (M&R) Stations (About 740 M&R stations above ground for pressures above 300 psig only) is incremental to CARB's Oil & Gas regulation.

e) What technology is required to implement the best practice and why?

Stationary methane detectors with telecommunication capabilities. Stationary methane detectors include point detectors with sensitivity varying from part per billion to percent gas, Optical Gas Imaging Systems (OGI) and Open Path methane detectors.

f) Will work require additional personnel and/or contract support? If so, please provide details.

Support to pilot investigations is included in the R&D projects described in the supplemental section attachments below.

g) What changes to existing operations are required? How will those changes be implemented?

No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
New procedures will be needed for the installation, maintenance and response to stationary methane sensors.

i) Timeline for implementation (Milestones):
Q2 2019: Tests of technologies and assessment of emissions of Regulation Stations (Above ground, >300 PSI). Technologies tested will be evaluated for leak monitoring application at storage facilities or compressor stations to comply with CARB Oil and Gas Rule.
Q2 2019: Define measurement protocol to establish emissions factors for Regulation Stations
Q4 2019: Definition of new emission factors for Regulation Stations based on leak and controller types
Q1 2020: Determination of stationary sensor deployment effectiveness

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
PG&E is using new technology to implement this best practice. New technologies often provide benefits that evolve over time. Some of the projects described above are funded through research consortiums and their costs are shared with other utilities or oil and gas companies. The average leverage ratio for the projects is higher than 5 which mean PG&E is paying approximately one-fifth of the research costs. This allows PG&E to keep R&D activities cost-effective. At this time, PG&E cannot quantify any cost-effectiveness or cost benefits related to the new technology.

k) Identify any cost benefits from this BP, when cost estimates are known:
See question j) above.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
Frequent Above Ground leak surveys (BP 19) can provide the same benefit as stationary leak detectors for methane emission reductions.

m) Anticipated Emissions Reductions from this BP:
By allowing the faster detection of more and smaller leaks from the gas system, this BP leads to methane emission reductions that can be represented by the adjustment of leak based Emissions Factors for the utilities implementing this BP. Field measurements will be performed to support the new Emissions Factors and calculate the abatement.

2015 Baseline Emissions affected, where known:
None anticipated at this time, see the response under part m) above.

n) Calculation Methodology:
Please see the response under part m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
This BP provides leak better detection tools that improve safety and contribute to methane emission

reduction.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

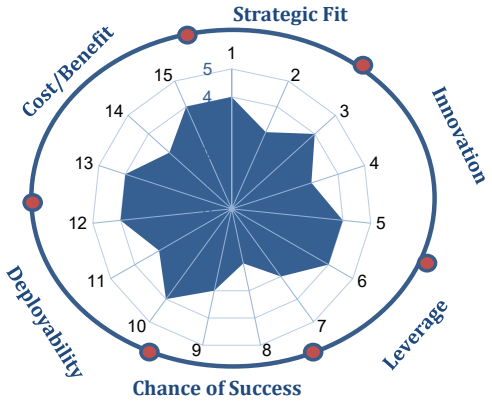
c) Research or Studies:
See attachments for additional details

- Evaluation of the state of the art in methane detectors. (OTD) (BP18_ATCH01).
- Quantification of methane emissions from Transmission M&R stations (BP18_ATCH02).

d) Other:
None.

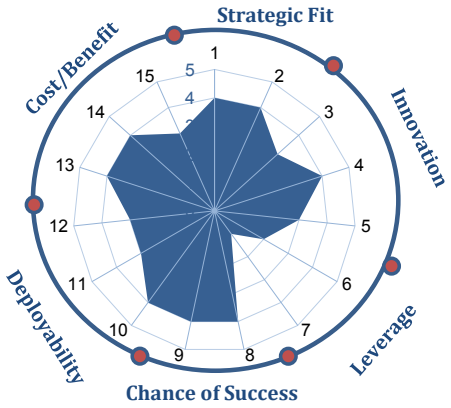
2016 Spring OTD project proposal (7.16.f): Methane Sensors state-of-the-art investigation

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	With the increased awareness and scrutiny on methane emissions, utilities can benefit from a project that will look at the potential use cases for methane sensing to abate emissions and improve public safety. This project will investigate the current state of the art in "point" methane sensors and perform a gap analysis to identify opportunities to implement the sensors by gas utility companies. In addition, the project will also evaluate a low-cost, virus-based methane sensor prototype developed by BioInspira, a startup from Berkeley.	4
	How does it fit in our overall strategy and rank among our priorities?	The development of this product fits into our goal of delivering natural gas safely and in an environmentally sustainable way.	3
Innovation	What is the state of the art?	Recently, NASA JPL has developed a very sensitive and lightweight handheld methane detector. PG&E has also piloted the use of stationary methane laser sensor to track methane emissions at one of its storage facilities. ARPA-E is funding 11 technology providers to develop methane sensors (point, ranged and optical imaging) through its MONITOR program. The opportunity to implement the use of methane sensors at PG&E has not been explored.	4
	What is the existing solution at PG&E?	PG&E uses methane detectors that are equipped with air pumps (Picarro, DPIR) or ranged infrared detectors (RMLD). PG&E does not utilize methane point sensors to monitor for leaks or to track emissions.	3
	How does the team compare to competition?	OTD has extensive experience in researching methane sensors for the industry and is well-suited to perform this study.	4
Leverage	How does the project leverage previous work?	This project will leverage prior work by OTD on "Methane Sensing for First Responders" and "Field Measurement of Methane Flow Rate" which aimed to develop distributed remote methane sensors for first responders in gas leak situations and to create a prototype flow rate measurement device based on the commercially available Hi-Flow sampler.	4
	What are the opportunities of co-financing?	The total cost of the project is $300,000. With funding from other utilities, the share of the cost for PG&E is expeceted to be ~$15,000.	3
Chance of Success	What are the risks for failure?	There is minimal risk of failure. The project will inform us of some the available options for methane sensing.	2
	What are the requirements for deployment at PG&E?	Promising methane point sensors identified through this project will need to have its sensitivity, reliability and performance verified before deployment.	3
Deployability	How will the solution be used?	This is an area for further research both within and outside the company.	4
	What additional delays have to be accounted for the	More delays can be expected from performing verification tests of the sensors.	3
	How does it synchronize with existing actions?	This project synchronizes with our actions to better track and measure the emissions from our system.	4
Cost vs Benefits	Can we assess cost benefits of the solution?	The use of this device would help regulatory compliance to identify leak sources to support our effort in minimizing methane emissions.	4
	What will the on-going cost of the solution after deployment be?	There will be maintenance and potential battery replacement costs associated with deploying methane point sensors.	3
	What is an acceptable cost target for PG&E?	$15k is an acceptable cost for PG&E.	4
		Total	**3.5**



2017 PG&E project: Evaluating Emissions from Transmission M&R stations

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	This is an internal PG&E project to investigate the amount and frequency of emissions from Transmission Metering and Regulating stations. In our 2017 annual leak report, transmission M&R stations is among the top three emission source categories alongside customer meters and distribution pipelines. An explanation for this is that the current emission factors for above ground stations are based on the outdated 1992 EPA study and we think that they overestimate current emissions. Since 1992, many technological advances have taken place which would have reduced both fugitive and vented emissions from these facilities. In this project, we will install portable open path sensors inside the facilities and continuously monitor the level of emissions for several months to better understand the behavior of these stations. Since the sensors only provide concentration readings, we'll supplement by organizing trips to measure flow rates with another device and attempt to quantify the emission contribution across the year. Once completed, the results can be used as a basis to engage CPUC to update the emission factors. According to FIMP, there are many components within a M&R station but a main source of emission is the pneumatic device which can be categorized into high-bleed, low-bleed, and intermittent bleed. For each category, we'll select a couple stations for a total of 6 stations.	4
	How does it fit in our overall strategy and rank among our priorities?	In addition to helping us understand how open path methane sensors can be used to address CARB Oil and Gas Rule for underground storage facility and SB 1371 Best Practices recommendations, this project also aligns well with PG&E's new vision to meet the challenge of climate change.	4
Innovation	What is the state of the art?	This project will utilize two open path sensors: Sensit Acutect FP-30 and Boreal GasFinder3. We have installed the FP-30 system at our Los Medanos storage facility for pilot testing and it has demonstrated reliability and robustness. Even though Boreal will be a new vendor for us, it has many years of experience building customized systems for installation in remote areas for oil and gas operators.	3
	What is the existing solution at PG&E?	PG&E currently does not keep track of emissions from M&R stations. The annual emission estimate is calculated using emission factors and population count.	4
	How does the team compare to competition?	Our team has some experience installing and analyzing data from open path sensors. That said, this will be a great learning opportunity for potentially adopting similar systems for wellhead monitoring at storage facilities.	3
Leverage	How does the project leverage previous work?	This project will leverage our experience installing open path sensors at storage facilities completed in 2016 under a PRCI project.	2
	What are the opportunities of co-	Since this is an internal PG&E project, there is no co-financing opportunity available.	1
Chance of Success	What are the risks for failure?	The risk for the project is to fail in collecting valuable data for improving emission factors for Transmission Regulation Station and for guiding improvements such as equipment replacement.	4
	What are the requirements for	The data obtained from this study can be used immediately to start a conversation with CPUC.	4
Deployability	How will the solution be used?	The results of the project will serve as the basis to engage CPUC in a discussion to update the current emission factors for Transmission stations which, in our opinion, are overestimated. In addition, the results will inform us on which type of devices are the biggest emitters at the stations.	4
	What additional delays have to be accounted for the full deployment?	In this case, full deployment is having CPUC update the emission factors for our annual report. This will involve several discussion with CPUC and possibly conducting a bigger study.	3
	How does it synchronize with existing actions?	This project synchronizes with past projects on using open path sensors to monitor emissions from wellheads. The results of this project will provide additional data point on how practical it is to use these sensors for facility monitoring. It will also contribute to the Best Practice 18 as mandated by the CPUC under SB 1371.	3
Cost vs Benefits	Can we assess cost benefits of the solution?	Using open path sensors to continuously monitor these facilities combined with spot measurements have a big advantage over doing spot measurements by itself. Though the cost is higher, we have a better representation of the activity of the station in over several months. The benefit of this project is intangible but assuming that the findings indicate much lower emissions at transmission M&R station, it allows us to allocate resources to mitigate emissions from other asset families. Potential savings of 40% at $7.00 Mscfh would create savings of $1.8M per year.	4
	What will the on-going cost of the solution after deployment be?	There is on-going cost associated with transporting the sensors between stations and gettign help from GPOM. After the project is completed, there is no cost required to share the data. Also savings will only be captured when replacement or amintenance is performed.	4
	What is an acceptable cost target for PG&E?	The estimated cost of this project is $100k which include purchase of two Acutect FP-30 sensors for $50k and and rental and purchase of Boreal GasFinder3 for another $50k.	3
		Total	**3.3**



PART 1: OVERVIEW

a) Best Practice: 19 **b) Status:** Pilot

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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

Currently foot patrol identifies leaks, appropriately grades the found leaks, and either rechecks or repairs the found leaks based on compliance dates. Survey is completed on a quarterly basis in compliance with CARB regulations. Other compliance surveys are completed on a semi-annual basis, in addition to audio and visual surveys performed on equipment daily.

b) Alternative Proposal to BP or exemption? No

c) Proposed Plan:

PG&E plans to enhance its historic work identified in question a) above with new technology and R&D as stated below in question e).

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

Oil & Gas regulation introduced by CARB covers Compressor Stations and Gas Storage Facilities. The application of the BP to City Gates, and Metering & Regulating (M&R) Stations (About 740 M&R stations above ground for pressures above 300 psig only) is incremental to CARB's Oil & Gas regulation.

e) What technology is required to implement the best practice and why?

PG&E is working to enhance its current practices by using Digital Catalyst software in the field to more effectively track data related to above ground leaks. Using Digital Catalyst, leaks will be entered into the software in the field and potential repairs identified within 30-45 seconds – much more quickly than occurs today. PG&E anticipates rolling-out this enhancement in 2019.

Digital Catalyst also communicates directly with SAP, which is the system of record for assets. This increases efficiency and effectiveness.

In parallel, R&D will explore new and advanced technologies to detect above ground leaks including gas imaging camera, low-cost point sensors, and drone-based leak quantification technology. See supplemental section below for additional detail.

f) Will work require additional personnel and/or contract support? If so, please provide details.

No additional resources are required.

g) What changes to existing operations are required? How will those changes be implemented?

Changes to existing operations will require training operators to use Digital Catalyst. Additionally, using the new technology will reduce manual data entry of survey data.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
New process flowcharts will need to be developed and dedicated trainings for surveyors will need to be added.

i) Timeline for implementation (Milestones):
PG&E anticipates deploying Digital Catalyst in 2019.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
Cost-effectiveness is still to be determined.

k) Identify any cost benefits from this BP, when cost estimates are known:
Cost benefits are unknown at this time.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
It is anticipated that efforts for this BP will overlap with BP 1, BP 2, and BP 16. This BP focuses on data management of leak surveys, which those three BPs will impact.

m) Anticipated Emissions Reductions from this BP:
Digital Catalyst application will improve the tracking of leaks at above ground facilities. The emissions savings associated with these facilities will be updated based on this information, and progress will be monitored through the annual leak report, pursuant to the Leak Abatement OIR. The Oil & Gas regulation introduced by CARB in 2017[11] directs compressors and storage facilities operators to perform quarterly leak surveys, to repair leaks quickly after discovery.

2015 Baseline Emissions affected, where known:
Please see the response under part m) above.

n) Calculation Methodology:
Please see the response under part m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:

[11] California Resource Board Regulation Order §95669
https://www.arb.ca.gov/regact/2016/oilandgas2016/ogfro.pdf

None.

b) Changes to Operations:
None.

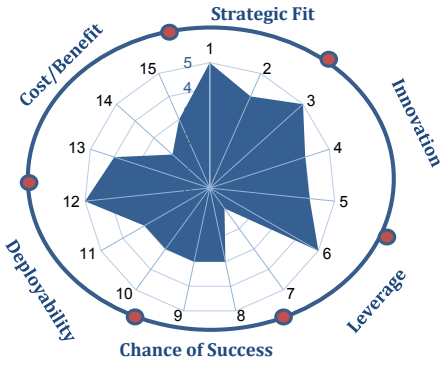
c) Research or Studies:
See attachments

- SeekOps UAS Leak Detection and Quantification (BP19_ATCH01);
- OTD project on Evaluating Gas Imaging Technologies (BP19_ATCH02); and
- Stanford Electrochemical Gas Sensor development project (BP19_ATCH03).

d) Other:
None.

2018 project: SeekOps Drone-based Leak Detection and Quantification

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	In our annual leak report to CPUC, emissions from M&R stations (distribution and transmission) account for a large portion of our total emissions. Being able to characterize the emissions from these source categories on a regular basis will provide an opportunity to update the emissions factors so that we can claim the benefits of any emissions reduction effort. The project will demonstrate a drone-mounted leak detector system from SeekOps to perform aerial leak detection and measurements at facilities including M&R stations. This technique is vastly more efficient and safer compared to the traditional method of bagging each component at the facility. In addition, the technology can be used to measure emissions from vent stacks that are hard-to-reach using backpack instruments. SeekOps leverages the sensor and expertise developed in our consortium projects with NASA JPL . In the beginning of the project, a controlled release test will be performed to fully evaluate SeekOps' ability. Then, Seekops will be asked to visit several M&R stations and Compressor Stations for data collection. If successful, this project can pave the way to operationalize drone use for leak detection and measurements at PG&E.	5
	How does it fit in our overall strategy and rank among our priorities?	This project is aligned with our vision of meeting the challenge of climate change, specifically it helps us to develop more cost-effective and safer techniques to collect facility-wide emission data from ourstations. Drone-based leak survey can also be used to assess conditions of our assets which is useful in maintaining a high level of safety.	4
Innovation	What is the state of the art?	Currently, drone-based leak detection and quantification can be considered state-of-the-art technology. Few organizations such as NYSEARCH and PRCI are actively testing and pursuing this technology. Since SeekOps utilizes the detector and lessons learned from our PRCI project with NASA JPL, they are very well in front of the pack when it comes to expertise in this area.	5
	What is the existing solution at PG&E?	Currently, to measure emissions from facilities, PG&E contracts the work out to a company who uses backpack instruments to quantify each leak. Regarding drone use, PG&E Aviation Services is still developing a program to allow use of drones in our operations. This project, contracted to SeekOps, will allow more testing and flight time to improve safety and accuracy of the technology before it is used on a broader scale within the company.	4
	How does the team compare to competition?	SeekOps uses technology from NASA/JPL. They are one of the pioneers in this field and have strong expertise in the domain.	4
Leverage	How does the project leverage previous work?	This project will directly leverage the research performed with NASA JPL and UC Merced under PRCI to develop the methane sniffer as well as preliminary effort to integrate the sniffer onto a quadcopter. In fact, the CTO of SeekOps is the graduate student who used to lead the drone research efforts at UC Merced.	5
	What are the opportunities of co-financing?	The total cost of the project is expected to be $50,000. No co-funding is planned at this time but result sharing will be explored with SoCalGas.	1
Chance of Success	What are the risks for failure?	Leak Localization and flux quantification has been done before on mobile leak survey platforms such as Picarro, but the accuracy and the inconsistency in the data leave much to be desired for. Improving the capabilities beyond what mobile technologies are capable of will be essential to justify the use of UAS versus mobile systems or backpack instruments.	3
	What are the requirements for deployment at PG&E?	The major limitations for the use of UAS at PG&E will be the regulations by FAA and potentially local restrictions. Training and safety procedures will also need to be developed and extensively tested.	3
Deployability	How will the solution be used?	The solution will be used to perform leak survey and quantification of our facilities such as M&R stations and compressor stations. The data can be used to update emission factors of these facilities to claim the benefits of any emissions reduction effort.	3
	What additional delays have to be accounted for the full deployment?	SeekOps will have to be certified under ISNetworld before they can perform work for PG&E. This is a way to ensure that our contractors have proper safety documentations and emergency preparedness.	3
	How does it synchronize with existing actions?	This project is in line with our efforts on improving leak detection to better understand our emissions profile, including use of Picarro for distribution system, testing of Ball Aerospace LiDAR-DIAL system for transmission leak survey, testing of stationary methane sensors at gas facilities.	5
Cost vs Benefits	Can we assess cost benefits of the solution?	Currently, there is no effective way to rapidly measure the overall emissions from a facility such as a M&R station. This project will provide a new method for doing so. The main benefit will be being able to collect data to update the emission factors to show regulators the impact of our ongoing emissions reduction effort.	4
	What will the on-going cost of the solution after deployment be?	On-going costs of the UAS will depend on applications and regulations. We have not received the details of the contracting costs with SeekOps yet.	2
	What is an acceptable cost target for PG&E?	The target cost of $50k for PG&E is reasonable since there is a large potential benefit in terms of safety and being able to show the impact of our emissions reduction efforts.	3
		Total	**3.6**



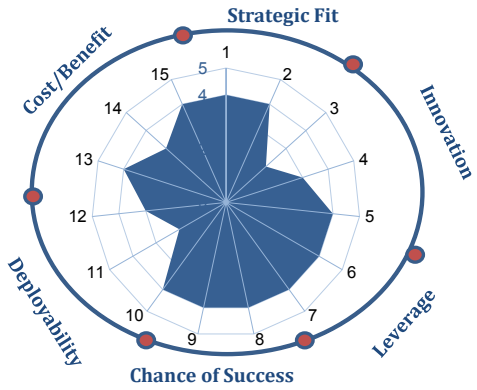
References:

FAA "Operation and Certification of Small Unmanned Aircraft Systems. Notice of proposed rulemaking". RIN 2120-AJ60. February 2015

L. Christensen, YQ Chen Methane Sniffer Small Unmanned Aerial System (ms-sUAV) Proposal to NYSEARCH February 2015.

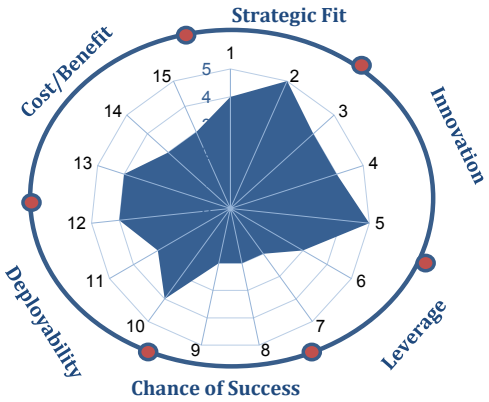
2017 Spring OTD project proposal (7.16.b): Evaluate Gas Imaging Technologies, Additional Scope

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	Gas imaging cameras are a tool that allows for detection, identification of leaks, and potentially quantification of leak flow rate. The original scope of the project is to evaluate use of gas imaging cameras for the gas industry. This proposed additional scope will evaluate two additional gas imaging cameras: TelOps Hyperspectral Imaging camera and VIRA Gas Imaging camera, by testing them on simulated underground leaks and meter set leaks at GTI test facility. The gas imaging cameras tested in the original project have difficulties in detecting diffuse underground leaks and meter set leaks due to little temperature difference between gas and soil or building background. They were, however, good for detecting larger leaks at CNG stations. This project offers a more comprehensive look at the technology by testing more instruments.	4
	How does it fit in our overall strategy and rank among our priorities?	This project will benefit PG&E's effort to detect and locate leaks and to meet requirements of new regulations such as CARB Oil and Gas Rule for underground storage facility and address Best Practices recommendations as part of SB1371 for natural gas leak abatement.	4
Innovation	What is the state of the art?	ARPA-E MONITOR program is funding Rebellion Photonics to develop a miniature gas imaging camera with leak quantification capability. Their stationary system was tested during the original phase of this project but had difficulties in detecting underground and meter set leaks. FLIR is partnering with Providence Photonics to develop gas leak quantification on their GF-series cameras ($>80,000) but is only suitable for large leaks. Heath, Sensit/VIRA have their own version of the gas imaging camera and our initial testing show that they are not sensitive to small leaks.	2
	What is the existing solution at PG&E?	PG&E has a couple of Heath's gas imaging cameras and have used them for leak detection at gas storage facilities. PG&E also contracts leak detection and quantification work to Montrose who uses FLIR GF-series cameras.	3
	How does the team compare to competition?	GTI/OTD has decades of experience working on leak detection technologies. They also have a controlled leak facility to evaluate the new technologies. OTD is well-positioned to carry on the additional testing.	4
Leverage	How does the project leverage previous work?	This project will leverage earlier phase of the project. The same experimental setup can be used to evaluate the two additional technologies.	4
	What are the opportunities of co-financing?	The additional cost for the supplemental scope for this 15-months project is $56,000. Assuming 5 utilities fund the project, the shared cost for PG&E is $11.2k. The cost of the original project is $231,000 which PG&E did not sponsor.	4
Chance of Success	What are the risks for failure?	Given that earlier testing was completed successfully with the set-up at GTI's facility, there should be little to no risk of failure in testing more instruments. However, it is known that gas imaging cameras are currently not very sensitive to small leaks making them unsuitable for distribution leak survey.	4
	What are the requirements for deployment at PG&E?	PG&E may need to conduct a pilot study at a gas storage facility prior to deploying this in the field. The handheld version of the instrument will have to be tested alongside existing leak survey instruments and have intrinsically safe design.	4
Deployability	How will the solution be used?	The technology can eventually be used to detect and locate leaks at facilities or even at distribution systems (once the sensitivity has improved). Having the leak quantification ability would accelerate the adoption of this device as it helps to fulfill the best practices recommended by SB 1371.	4
	What additional delays have to be accounted for the full deployment?	The technology has to improve to the point that it is as sensitive as currently used handheld leak survey equipment.	2
	How does it synchronize with existing actions?	This project synchronizes with our testing of stationary methane detectors for continuous monitoring of facilities to have an overall strategy for monitoring and rapid localization of leaks at facilities.	3
Cost vs Benefits	Can we assess cost benefits of the solution?	The benefit of using gas imaging camera compared to conventional sniffers is faster leak detection and localization at facilities . Assuming the net increase in speed is 30%, at $40,000 a month of leak survey cost at all three storage facilities, the savings can be $12,000/month. In addition, being able to quantify emissions from leaks will help tremendously with annual reporting and can potentially reduce contract costs.	4
	What will the on-going cost of the solution after deployment be?	Once deployed, gas imaging cameras will require maintenance and calibration just like current equipment.	3
	What is an acceptable cost target for PG&E?	$11.2k is an acceptable cost for PG&E considering the positive effect this may have in educating us about the advances in leak detection and quantificatio technologies.	4
		Total	**3.5**



Project: Development of a micro electrochemical methane sensor - Stanford

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	Detection of leaks is paramount for safety and for methane emission abatement. This project is the second phase of the development of a new technology for a "point" methane sensor that can be installed near assets with high propensities to leak. Challenges to be addressed for a permanent detection system are cost, false alarms, and durability. The new technology proposed by Stanford is based on the redox potential signature of methane and can be easily scaled down in an electronic chip for integration into a device. It may be an alternative to other methane sensing technologies such as micro-oscillator developed by NYSEARCH, laser-based systems, virus-based detector proposed by Bio-Inspira. The phase 1 of the program completed in 2017 has shown the feasibility of the concept. THis second phase will focus on developing functional prototypes up to field testing.	4
	How does it fit in our overall strategy and rank among our priorities?	Continuously detecting leaks is a growing demand both for safety, with potential residential applications, and for methane emissions. The project is also part of our strategy to develop a stronger relationship with Stanford University.	5
Innovation	What is the state of the art?	A broad range of technologies have been explored for methane detection ranging from optical techniques such as passive infrared measurements (FLIR cameras), laser spectrometers (JPL, Heath, Licor, Picarro, ABB/LGR, etc.), micro-resonators and carbon nanotube cantilever, as well as virus based. Challenges persist on cost, false alarm, sensitivity, stability, etc.	4
	What is the existing solution at PG&E?	PG&E uses methane detectors that are equipped with air pumps (Picarro, DPIR) or ranged infrared detectors (RMLD). PG&E does not utilize methane point sensors to monitor for leaks or to track emissions.	4
	How does the team compare to competition?	Stanford has demonstrated during the first phase of the program that redox signature can be used for the development of micro sensors. The laboratory assembles the best in class chemistry and micro-manufacturing capabilities that are key to the success of this technology development.	5
Leverage	How does the project leverage previous work?	This project will leverage work already performed by Stanford for the detection of CO_2 and methane. The measurement concept has been demonstrated. The project will focus on the development of functional prototypes to be tested in laboratory and in the field..	3
	What are the opportunities of co-financing?	The project is run through the Natural Gas Initiative at Stanford and is co-funded by SoCalGas. PG&E funding is of $100k on a total of $214k for a leverage ratio of 2.1.	2
Chance of Success	What are the risks for failure?	It is the development of a new technology. The risk of failure is high but it may open possibilities for a new generation of methane sensors.	2
	What are the requirements for deployment at PG&E?	At the end of this project, if results are positive, work will need to be performed to industrialize the sensor. At this stage, we plan to propose NYSEARCH, OTD, and PRCI to take the lead.	2
Deployability	How will the solution be used?	The sensors will be used on specific points with higher risks of leaking such as fittings, valves, etc. The sensor may also be embedded in customer products to detect methane in houses.	4
	What additional delays have to be accounted for the full deployment?	Industrialization and commercialization will be the major steps following the completion of this project.	3
	How does it synchronize with existing actions?	This project synchronizes with our actions to develop new ways to detect and measure methane leaks. The project will contribute also to provide a new approach to the state-of-the-art study being performed by OTD (Project# 7.16.f).	4
Cost vs Benefits	Can we assess cost benefits of the solution?	The use of this device would help regulatory compliance to identify leak sources to support our effort in minimizing methane emissions.	4
	What will the on-going cost of the solution after deployment be?	There will be maintenance and potential battery replacement costs associated with deploying methane point sensors.	3
	What is an acceptable cost target for PG&E?	$100k is an acceptable cost for PG&E.	3
		Total	**3.5**



PART 1: OVERVIEW

a) Best Practice: 20a **b) Status:** R&D

Quantification & Geographic Tracking

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 for the purpose of tracking emissions reductions.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E has started to explore leak quantification through a NYSEARCH project in 2014. The results of this project have shown the uncertainty of mobile survey when measuring flow rate of leaks on the distribution system. These results have been used in establishing the super emitter method described in BP 21. In addition, PG&E and NYSEARCH have collaborated with the Pipeline and Hazardous Material Safety Administration (PHMSA) to establish a method to validate results found by leak quantification systems.

In parallel PG&E has initiated other R&D projects with Operations Technology Development (OTD) and NYSEARCH to improve and develop new techniques for leak quantification. See the supplemental section below for more information about R&D projects.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E proposes to continue the R&D projects as mentioned in question a) above, and use the results to refine emission factors and establish emission factors specific to the utility.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

No overlap with other regulations.

e) What technology is required to implement the best practice and why?

The technologies are being developed through R&D. The final technology implemented will depend upon those results.

f) Will work require additional personnel and/or contract support? If so, please provide details.

No additional support is anticipated.

g) What changes to existing operations are required? How will those changes be implemented?

No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.

New procedures specific to leak quantification will be developed after R&D is completed.

i) Timeline for implementation (Milestones):

Dates range across technologies and programs. Each project has its own timeline and milestones which will be provided when available.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
No costs are associated with this BP at this time.

k) Identify any cost benefits from this BP, when cost estimates are known:
See question j) above.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
Results of this BP will support several other BPs, including BP 17, BP 18, BP 19, BP 20b, and BP 21, which relate to leak survey and repair prioritization.

m) Anticipated Emissions Reductions from this BP:
No emissions reductions are anticipated at this time.

2015 Baseline Emissions affected, where known:
Please see the response under part m) above.

n) Calculation Methodology:
Please see the response under part m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

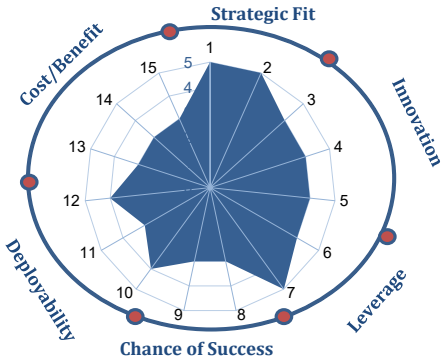
b) Changes to Operations:
None.

c) Research or Studies:
See attachments for OTD (BP20a_ATCH01) and Gas Flow Imaging (BP20a_ATCH02) as described in part a) above.

d) Other:
None.

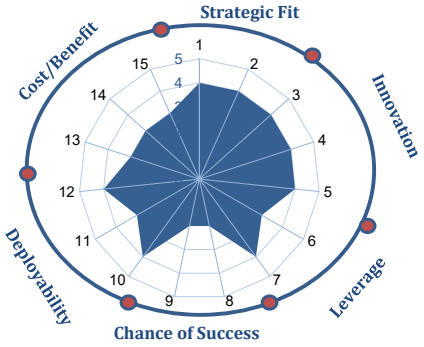
2015 Spring OTD project proposal (1.14.d): Field Measurement of Leak Flow Rate Phase 2

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	Following the Senate Bill 1371, CPUC is adopting rules for minimizing emissions of natural gas from pipeline leaks. One key challenge is the quantification of non-hazardous leaks in the pipeline system at a reasonable cost. Efforts have been launched through our participation in NYSEARCH earlier this year focusing on evaluation of technologies and developing a validation process. This OTD project is a Phase 2 effort to develop a tool to quantify leak rate of non-hazardous leaks. Phase 2 will focus on making improvements to the prototype to allow increased accuracy, precision, lower cost and ease of use. The expected project duration is 24 months.	5
	How does it fit in our overall strategy and rank among our priorities?	A field-ready method to quantify leak flow rates would allow gas companies to report emissions to the regulators for compliance, provide additional data in addition to leak grades to prioritize pipe replacement decisions and scheduling to address non-hazardous leaks.	5
Innovation	What is the state of the art?	For direct measurements of leak flow rate, the Hi-Flow Sampler (pump with methane sensor) and VPAC (acoustic measurement device) have been used by the industry but the Hi-Flow Sampler is suited for leaks that are larger than 3 scfh while VPAC is known to have accuracy issues. Remote measurement technique typically uses a mobile methane analyzer (Picarro, LGR methane analyzer, Licor 7700) to measure the methane concentration downwind of the leak area to estimate the emission. This mobile technique is not suitable for quantification of small individual point-source leaks.	4
	What is the existing solution at PG&E?	Currently, PG&E does not have a validated method to quantify leak flow rates. Leak survey crews measure the concentration of methane close to a leak source but not the flow rate.	4
	How does the team compare to competition?	OTD/GTI was instrumental in the development of the Hi-Flow sampler and has a lot of experience in methane emissions measurement. OTD will base the new tool on the Hi-Flow Sampler and modify the gas sensor to be more sensitive to smaller leaks.	4
Leverage	How does the project leverage previous work?	This project leverages several completed and ongoing OTD projects on measurement of leak flow rates including "Field Measurement of Leak Flow Rate", "Improving Methane Emission Estimates for Natural Gas Distribution Companies".	4
	What are the opportunities of co-financing?	The total project cost is $500,000. Assuming the $250,000 co-funding from PHMSA is approved, the share for PG&E will be $40,000 to $50,000.	5
Chance of Success	What are the risks for failure?	The risk of failure is limited by OTD's experience on flow rate measurement. Nevertheless, finding a sensor that is sensitive to the small volume rate leaks is a significant challenge.	3
	What are the requirements for deployment at PG&E?	The requirements are that the technology and process have to be validated through lab and field tests which will be covered by this phase 2 project.	3
Deployability	How will the solution be used?	It is likely that leak surveyors will carry a leak quantification device so that they can grade and quantify a leak in parallel. The data will be passed on to the risk management and pipeline engineering to draw priorities on scheduling for leaks that are non-hazardous.	4
	What additional delays have to be accounted for the full deployment?	There could be additional delays associated with obtaining approval from regulators.	3
	How does it synchronize with existing actions?	This project would synchronize with PG&E's action to explore different technologies for leak quantification at NYSEARCH including a project to test the feasibility of Schlieren optical imaging and another project to develop a mobile leak quantification technique.	4
Cost vs Benefits	Can we assess cost benefits of the solution?	Ultimate cost associated with methane emissions may be a tax on Green House Gases. Using the Global Warming Potential defined by the 5th Assessment Report of the Intergovernmental Panel on Climate Change [2013], a leak rate of 0.3% of delivered natural gas, and a tax of $15 per ton of CO2 equivalent, the cost would be of $8M per year. In addition, assessment methods for methane emissions may be extremely costly to deploy if a reasonable validation method is not proposed.	3
	What will the on-going cost of the solution after deployment be?	There will be additional costs associated with training current leak surveyors and the extra time taken by field crews for quantifying leaks. The added cost will not be significant as the quantification can be done in parallel with current efforts to locate and grade leaks.	3
	What is an acceptable cost target for PG&E?	Considering the high long term value that the project might bring, $50,000 is an acceptable cost for PG&E.	3
		Total	**3.8**



NYSEARCH June 2017 Proposal : Stand off Gas Flow Imaging and Analysis System Phase II (M2015-002 PhII)

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	To date, methane quantification remains a challenging problem due to the stochastic nature of methane plume dispersion and the added variability that enviromental factors bring. Techniques that have been attempted include using a portable pump with combustible gas sensor (Hi-Flow sensor) and mobile gas spectrometer (Picarro) but there has not been a method that achieved the needed level of practicality and accuracy. This project will explore a technique using Schlieren optical imaging to develop a portable, field usable imaging system that estimates gas plume velocity and determines a flow rate value. The first phase of the project succesfully demonstated two approaches to indirectly determine the leak orifice diameter to find flow rates of leaks in lab conditions with accuracy of ± 6%. This second phase will explore whether the techniques used in the lab in phase I can be successfully applied in the field for outdoor leaks.	4
	How does it fit in our overall strategy and rank among our priorities?	A field-ready method to quantify leak flow rates would allow gas companies to report emissions to regulators for compliance, provide additional data in addition to leak grades to prioritize pipe replacement decisions and repair for non-hazardous leaks.	4
Innovation	What is the state of the art?	Most available types of methane detectors, such as laser light absorption, infra red spectroscopy, and electrochemical sensing, mostly provide point concentration readings but do not directly measure fluid flow properties which makes leak flow rate quantification difficult. Schlieren imaging is an optical method for remote observation of leaks and is able to provide flow velocities and direction based on changes in images taken at high frequency (one image every second). Using multiple Schlieren cameras from different angles would provide a 3 dimensional picture of the leak plume and a better representation of the flow conditions. As cost of cameras and near infrared laser sources have declined in the past years, the Schlieren optical technology can be set up with off the shelf products for a few hundred dollars.	4
	What is the existing solution at PG&E?	Currently, PG&E does not have a validated method to quantify leak flow rates. Leak survey crews measure the concentration of methane close to a leak source but not the flow rate. To be noted, PG&E R&D and Innovation is testing Picarro Emission Quantification vehicle for wellheads at storage facilities. Such systems have been shown, in a NYSEARCH project, to have order of magnitude accuracy.	4
	How does the team compare to competition?	SRI International and Floviz are believed to be the front runner in this field and are well-suited for the project. The team from Floviz includes Dr. Gary Settles of Penn State University who has over 15 years of experience in this field and is considered a pioneer in the technology. SRI also brings to the table deep expertise in optical imaging and state-of-the -art facility and instruments.	4
Leverage	How does the project leverage previous work?	This project leverages the decades of research performed by FloViz on their Schlerien techniques and the expertise that SRI International brings on optical imaging.	3
	What are the opportunities of co-financing?	The total project cost of $245,654 will be shared among participating NYSEARCH members, the share for PG&E will be $31,695 for a leverage ratio of 7.8.	4
Chance of Success	What are the risks for failure?	The risk of failure is mitigated by the fact that both vendors have decades of experience in the field of Schlieren optical imaging and results from first phase are good. The challenge is to develop a system that can work in complex environment and wind conditions. There will be a GO/NO-GO phase at the end of Task 4 (outdoor leak test).	2
	What are the requirements for deployment at PG&E?	The requirements are that the technology and process have to be validated through lab and field tests.	2
Deployability	How will the solution be used?	Leak surveyors can use this instrument to detect, locate and measure leaks in distribution systems or at facilities. The data will be passed on to the risk management and pipeline engineering to draw priorities on scheduling for leaks that are non-hazardous.	4
	What additional delays have to be accounted for the	There could be additional delays associated with commercializing the product.	3
	How does it synchronize with existing actions?	This project would synchronize with PG&E action to explore different technologies for leak quantification including UAV-mounted detectors (NASA JPL), and OTD improved Hi-flow sensor. NYSEARCH is also working on a another project to evaluate several mobile platforms with leak flow rate quantification capability. In addition, NYSEARCH will develop a protocol to validate the findings of these tools based on methodologies used in in-line inspection world. ARPA-E's MONITOR program is also developing leak quantification technologies.	4
Cost vs Benefits	Can we assess cost benefits of the solution?	Ultimate cost associated with methane emissions will be a tax on Green House Gases. Using the Global Warming Potential defined by the 5th Assessment Report of the Intergovernmental Panel on Climate Change [2013], a leak rate of 0.3% of delivered natural gas, and a tax of $15 per ton of CO2 equivalent, the cost would be of $8M per year. Having a tool to quickly find large emitters can help us stop the leaks quickly.	3
	What will the on-going cost of the solution after deployment be?	There will be additional costs associated with training current leak surveyors and the extra time taken by field crews for quantifying leaks. The added cost will not be significant as the quantification can be done in parallel with current efforts to locate and grade leaks.	3
	What is an acceptable cost target for PG&E?	Considering the high long term value that the project might bring, $40,000 an acceptable target cost for PG&E.	3
		Total	**3.4**



1 Imaging Gas Leaks using Schlieren Optics. 1999. Dr Gary Settles.
http://www.me.psu.edu/psgdl/Pubs/1999-Settles-PGJ.pdf

PART 1: OVERVIEW

a) Best Practice: 20b **b) Status:** In Progress

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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E has the ability to track leaks in its enterprise systems of record such as Geographic Information System (GIS) and SAP. These systems track the location and grade of the leaks. PG&E's current technology is capable of transferring leak data to a central database in order to provide data for leak maps.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan: As mentioned above, PG&E currently has the ability to geographically track and evaluate leaks, and transfer leak data to a central database in order to provide data for leak maps. PG&E is working with the Environmental Defense Fund (EDF) on a publicly available geographic leak map that displays leak information at least by zip code or census track. PG&E is exploring ways to focus this information on emission levels and reductions in order not to cause undue customer concerns. Once a proposal is developed with EDF, PG&E plans to extend working discussions to other utilities, the CPUC and ARB staff in order to learn from and share implementation experiences.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

No other regulations overlap.

e) What technology is required to implement the best practice and why?

No additional technology is expected to be required for this BP, although the public-facing interface has yet to be developed at PG&E.

f) Will work require additional personnel and/or contract support? If so, please provide details.

Additional support may be required for development of the public-facing interface.

g) What changes to existing operations are required? How will those changes be implemented?

No changes to existing operations are expected to be required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.

No new procedures are expected to be required**.**

i) Timeline for implementation (Milestones):

As described above, PG&E is collaborating with EDF and other parties on an implementation plan, including an appropriate timeline. Tentatively, PG&E is targeting launch of the publicly available site in

2018 or as soon as practicable.
j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined: Cost-effectiveness has not been determined at this time.
k) Identify any cost benefits from this BP, when cost estimates are known: See question j) above.
l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap? See question j) above.
m) Anticipated Emissions Reductions from this BP: PG&E does not anticipate emission reductions from this BP. **2015 Baseline Emissions affected, where known:** See PG&E's response to question m) above.
n) Calculation Methodology: See PG&E's response to question m) above.
o) Additional Comments: None.
p) Overlap with Safety: Availability of leak geography data may improve public awareness, which may increase the likelihood of customers calling PG&E when they smell gas. This could have a positive safety impact through the faster identification and repair of hazardous or Grade 1 leaks.
SUPPLEMENTAL INFORMATION
a) Technology: None.
b) Changes to Operations: None.
c) Research or Studies: None.
d) Other: None.

PART 1: OVERVIEW

a) Best Practice: 21 **b) Status:** Pilot

"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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

Historically, PG&E has repaired leaks in its system in application of General Order No. 112-F based on the hazard a leak represents characterized by its grade. PG&E repairs all Grade 1 leaks immediately and Grade 2 leaks within 12 months, with a six-month recheck. PG&E also repairs all Grade 3 (non-hazardous) leaks on its transmission system within one year. PG&E has regularly monitored Grade 3 distribution system leaks consistent with General Order No. 112-F.

As part of this monitoring, PG&E repairs any below-ground Grade 3 leak that has developed into a higher-grade leak consistent with the timelines set forth above, and removes leaks from the monitoring program that no longer exist due to pipe replacement work and methane found to not be PG&E gas, such as sewer gas, naturally occurring methane or a gas leak on a house facility for which the owner is responsible to repair. PG&E annually rechecks Grade 3 leaks and at that time will determine if the leak should be removed for these reasons. Typically, approximately 30% of Grade 3 leaks are removed from the monitoring program annually for these reasons.

As of June 19, 2017, when the Commission issued D.17-06-015, PG&E had identified 3,839 above-ground Grade 3 leaks and 7,960 below-ground Grade 3 leaks for monitoring. PG&E considers this population of leaks to be its "leak backlog" per D.17-06-015, Ordering Paragraph 5. The 30% leak attrition rate mentioned above will reduce the below-ground Grade 3 backlog that needs to be repaired from 7,690 to 5,572 in 2018 and 2019.

b) Alternative Proposal to BP or exemption? None.

As detailed below in section (c), PG&E proposes a combination of accelerated leak detection and repair of larger Grade 3 leaks ("Super Emitters"), as well as repair of other Grade 3 leaks to reduce its Grade 3 leak backlog in 2018 and 2019 compared to the 4-year leak survey plan.

Using this approach, PG&E will repair 70% of the "backlog" as defined above by end of 2019, and anticipates that the number of leaks remaining open in its leak backlog as of June 2020 (3 years from the issuance of D.17-06-015) will be relatively small. PG&E proposes to identify any remaining open Grade 3 leaks in the backlog when it submits its 2020 Best Practices Compliance Plan and to propose an appropriate exemption for repair of those leaks at that time as warranted.

PG&E expects an overall increase in leak repair work in the 2020 to 2022 time period as a result of the move to a three-year leak survey cycle and the increased use of Picarro mobile leak detection technology to identify Super Emitters for repair, but plans to continue to repair Grade 3 leaks in a similar

fashion to the 2018-2019 period. PG&E will address its approach to leak repair in 2020 to 2022 in more detail in its 2020 GRC filing.[12]

c) Proposed Plan

1. Leak Quantification:

PG&E will perform accelerated leak surveys on an annual basis using Picarro mobile leak quantification technology recently developed and validated to identify the "Super Emitters" in its leak backlog. PG&E proposes to classify any existing Grade 3 leak as a Super Emitter if it is emitting more than 10 scfh. See Section g below for additional details.

2. Repair of Super Emitters in the Leak Backlog:

In 2018-19, PG&E will repair all Grade 3 Super Emitters identified in the accelerated leak surveys described above.

3. Repair of Additional Leaks

In addition to the Super Emitters, PG&E will repair approximately 19,484 above-ground Grade 3 leaks and 1,987 below-ground Grade 3 leaks per year in 2018, and will repair approximately 19,038 above-ground Grade 3 leaks and 1,944 below-ground Grade 3 leaks in 2019.[13]

4. Assumed Leak Backlog Attrition Rate:

Based on its historic below-ground Grade 3 leak attrition rate, outlined above, PG&E assumes that 30% of its leak backlog will be resolved either because a leak was upgraded to a Grade 1 or Grade 2 leak and repaired pursuant to those timelines, or because the leak was eliminated for other reasons, as stated above. Applying this assumed attrition rate, PG&E estimates that ~2,388 below-ground Grade 3 leaks in its leak backlog will be resolved in 2018 and 2019 other than by repair of a Grade 3 leak.

5. Remaining Leaks in the Leak Backlog:

As noted above, after PG&E's proposed plan is implemented in 2018 and 2019, any leaks remaining after June 19, 2020 in its leak backlog are expected to be relatively small in number. PG&E proposes to identify any remaining leaks when it submits its 2020 Best Practices Compliance Plan and to propose an appropriate exemption for repair of those leaks at that time as warranted.

6. Repair of Newly Discovered Grade 3 leaks Not in the Leak Backlog:

As noted above, PG&E expects an overall increase in repair work in the 2020 to 2022 time period as a

[12] PG&E is committed to maintain its Grade 3 leaks at or below its end of year 2017 levels. As a result, PG&E's plan is to repair Grade 3 leaks (above and below ground) to reduce open Grade 3 leaks by approximately 2% per year from 2017 levels.

[13] Actual leak repairs might vary depending on leak find rates and G3 leaks naturally leaving the pool of open leaks at the end of each year.

result of the move to a three-year leak survey cycle and the increased use of Picarro mobile leak detection technology to identify Super Emitters for repair. This will result in an increased need for leak repair funding in the 2020 to 2022 time period.

PG&E will address in its 2020 GRC Filing, how it proposes to repair G3 leaks in the 2020-22 time period.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?
No; this proposal, specific to leak emission abatement rather than repair of leaks based on safety hazard, does not overlap with any existing regulations. As noted within GO 112-F, all leaks on transmission pipelines must be repaired within a year of their discovery. The above methodology and proposal only applies to distribution leaks. All Grade 3 leak repair work is incremental to existing regulations, which require these leaks to be monitored regularly but not repaired.

e) What technology is required to implement the best practice and why?
The proposed plan leverages new methane detection and leak quantification technologies that have been developed in the past few years.

f) Will work require additional personnel and/or contract support? If so, please provide details.
PG&E anticipates two additional personnel (contractors) to perform these super emitter surveys.

g) What changes to existing operations are required? How will those changes be implemented?
PG&E currently conducts compliance surveys on a portion of its system each year, and uses leak grades, a methodology which ranks leaks based on risk, for repair and monitoring. The new Super Emitter survey, which is performed in addition to existing compliance surveys, will prioritize repairs based on methane concentrations. Two Picarro cars will be dedicated to this leak survey. These vehicles will cover the portion of the service territory not covered by PG&E's compliance survey. The data from both the supplemental survey and PG&E's compliance survey will be reviewed to prioritize leaks with flowrate greater than 10 scfh.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
Additional standards outlining the Super Emitter survey process may need to be developed. Development of additional procedures is currently under review. The general leak repair scheduling will include the quick repair of leaks identified through the Super Emitter survey.

i) Timeline for implementation (Milestones):
As noted within PG&E's Super Emitter White Paper, see supplemental section below, the method and software for the proposed accelerated leak quantification has been developed as part of studies conducted by PG&E and Picarro in 2016 and 2017. Given that minimal resources are required to support this supplemental survey, PG&E anticipates that surveys can begin approximately three months after the approval of this proposal. PG&E will also update or create any necessary processes or procedures in parallel.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
Focusing on identifying and repairing the largest leaks in the leak backlog as proposed while also working to reduce the overall leak backlog is the most cost-effective way to substantially reduce emissions from the distribution system, as well as to identify those leaks in the leak backlog that may be cost prohibitive to repair on a $/scfh basis.

Super Emitter Program:
The methane abatement resulting from the Super Emitter Program as calculated in the attached white paper are 119 MMscf for the first year (2018) and 129 MMscf for each of the following years (2019). The cost associated with the program includes the cost of the mobile survey and the cost of the associated leak repairs.

The cost of mobile survey is formed with the following assumptions:

- Distance to survey: 75% of (1-25%) of the total mileage of distribution mains (42,000 miles). The first coefficient (75%) accounts for the fact that 25% of the territory is already covered by safety survey (4 year survey cycle). The first coefficient (1-25%) comes from the fact that 25% of PG&E's territory cannot be surveyed with a mobile equipment.
- Speed of the mobile survey is 20 miles per hour.
- The total cost of the mobile survey is $100 per hour.

With these assumptions, the cost of the Super Emitter Program mobile survey is $708k per year.

The removal of the Super Emitter leaks (>10scfh) requires the repair of 300 leaks for the first year and 100 leaks for the years after. The unit cost of repairing a below ground leak on a main is $10,591 in 2018 and $9,303 in 2019 including overhead.

With these assumptions the cost of repairing the Super Emitter leaks is $3,177k in 2018 and $931k in 2019.

The cost effectiveness of the program is obtained by dividing the total expenses over 2018 and 2019 ($5.5M) by the total abatement for the same period of time (248 MMscf). It is: $22/Mscf.

Grade 3 Backlog Reduction program:
The estimated numbers of additional Grade 3 leaks to be repaired through the backlog reduction program are 1986 in 2018 and 1944 in 2019. The methane abatement resulting from these repairs is of 19 MMscf in 2018 and 51 MMscf in 2019. The average cost of repairing a Below Ground Grade 3 leak is $10,344 in 2018 and $10,923 in 2019 including expense and capital cost for leaks on mains and services and overhead. Therefore, total cost of repairs related to the program is $41.8M.

The cost effectiveness of the program is obtained by dividing the total cost over 2018 and 2019 by the total abatement for the same period of time (70 MMscf). It is: $591/Mscf.

The Super Emitter program is therefore 27 times more cost effective than the Backlog Reduction program from a $/Mscf perspective.

Additional details may be found in the Super Emitter white paper, see supplemental section below.

k) Identify any cost benefits from this BP, when cost estimates are known:
The abatement of 0.159 Bcf/y as calculated in m) will lead to cost saving of $ 3,260k/y corresponding to the WACOG of the 2018 Illustrative Gas Supply Portfolio: $2.05/therm.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?

Minor overlaps exist with the BP 15 which aims at accelerating the frequency of compliance leak surveys. Since BP 15 will lead to a larger share of the system to be covered every year through compliance surveys, the distance to be covered by the large leak mobile survey will be reduced.

m) Anticipated Emissions Reductions from this BP:
The implementation of this Best Practice is expected to produce an average annual abatement in 2018 and 2019 of 124 MMscf/year for the Super Emitter program and an additional 35 MMscf/year for the repair of below-ground Grade 3 leaks.

2015 Baseline Emissions affected, where known:
Emissions of the distribution system pipeline leaks in 2015 were of 626 MMscf.

n) Calculation Methodology:
The emissions reduction calculations are explained in detail in the attached document. The reduction in emissions is due to accelerating super emitter detection and repair. See the supplemental section below for additional details.

o) Additional Comments:
None.

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
The proposed program is the result of research performed by PG&E and Picarro in 2016 and 2017 can be found in BP21_ATCH01 .

d) Other:
See attachment BP21_ATCH02 for the calculation methodology support.

Accelerated detection and repair of large leaks in a gas Distribution system to reduce methane emissions

INTRODUCTION

It has been systematically observed that methane emissions from natural gas systems are skewed by a relatively small number of larger leaks that widely surpass the others[1]. Data used to compute Emission Factors for distribution systems established through direct field measurements of known leaks has shown the same distribution[2,3]. Pacific Gas and Electric Company (PG&E) recognized an opportunity to conduct a leak survey aimed at targeting these large leaks to provide significant emission reductions. This approach would supplement ongoing compliance surveys, which are aimed to minimize system risk, with an accelerated leak survey aimed at identifying and repairing larger leaks of the system as recommended by Adam Brandt et al[4].

Additionally, PG&E has outlined how existing research can be used to adjust Emission Factors for these larger leaks, as well as open leaks that remain once these larger leaks have been repaired.

While traditionally mobile surveys have prioritized indications using concentration, the proposed super emitter survey uses predicted flow rate. Recently, NYSEARCH provided a rigorous assessment of mobile methane detection accuracy to predict the flow rate of known leaks in a Distribution System[5] and this validated approach is the foundation of PGΘE's proposed supplemental survey.

CALCULATION OF METHANE EMISSIONS FROM A GAS DISTRIBUTION SYSTEM

Methane emissions from a Gas Distribution System are calculated by assigning a standard flow rate, also known as the Emission Factor (EF), to each leak. The EF's were developed using field measurements as part of two major studies; the Environmental Protection Agency/ Gas Research Institute (EPA/GRI) 1992 study[2] and the Washington State University (WSU) 2015 study (See Figure 2 and Table 2 in Appendix).

The formula below shows the total number of leaks (from both surveyed and unsurveyed regions) as a function of the survey frequency:

$$N_{total} = N_{X,L} \cdot (C_i + 1) \quad (1)$$

[1] Adam R. Brandt, Garvin A. Heath, and Daniel Cooley "Methane Leaks from Natural Gas Systems Follow Extreme Distributions" Environ. Sci. Technol., 2016, 50 (22), pp 12512–12520

[2] M Harrison et al/"Methane Emissions from the Natural Gas Industry/Volume 2. Technical Report" EPA-600/R-96-080b June 1996 (measurements completed in 1992, published in 1996)

[3] Brian Lamb et al/"Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States" Environ. Sci. Technol., 2015, 49 (8), pp 5161–5169

[4] Chandler E. Kemp, Arvind P. Ravikumar, and Adam R. Brandt "Comparing Natural Gas Leakage Detection Technologies Using an Open-Source "Virtual Gas Field" Simulator" Environ. Sci. Technol. 2016, 50, 4ǫ4c o4ǫǫƫ

[5] D/D'Zurko, and J/ Mallia "NYSEARCH Methane Emissions Technology Evaluation Θ Test Program" 2017 Natural Gas STAR and Methane Challenge Annual Implementation Workshop October 24-26, 2017, Houston, TX

$$with\ C_i = \frac{i-1}{2}$$

With:

N_{total} = Number of leaks in the distribution system

$N_{X,L}$= Number of leaks found during the survey

i = period of the survey in years

It should be noted that methane emissions are not only driven by the delay in leak repair after detection but also by the frequency of leak survey which determines how early new leaks are detected.

VALIDATING MOBILE SYSTEMS TO QUANTIFY LEAK FLOW RATE

A recent study[6] completed by NYSEARCH measured the effectiveness of mobile instruments to quantify methane leakage rates.

The study included two controlled tests held at the training facilities of the Public Service Enterprise Group (PSE&G) in New Jersey and Southern California Gas Company in California. A broad range of leaks were simulated with well-defined flow rates.

The third test was performed in the field in a suburban area close to New York. Actual leak flow rates were measured using a Hi Flow Sampler®. Results for the three studies are shown in Figures 2 through 7.

Different technologies showed similar performance in the different environments. The methodology proposed within this paper combines all data gathered to characterize the accuracy of mobile leak quantification systems. A total of 77% of the measured leaks were within an order of magnitude of the actual leak flow rate.

The accuracy of the flowrate measurement from the mobile technology was evaluated to ensure this method would be able to detect large leaks, and serve as a screening tool to differentiate leaks that are 10scfh or greater. The table below summarizes the accuracy of the tool for different flow rates into the following bins[7]:

[6] NYSEARCH's Technical Evaluation and Test Program for Yu antifying Emissions for Non-Hazardous Leaks (M2014-004) study is currently unpublished

[7] NYSEARCH data was previously calibrated to assure that errors were equally distributed between over and under estimating.

Actual leak <1 scfh	1 scfh<Actual leak<10 scfh	Actual leak> 10 scfh
73%	71%	78%

Table 1: Leak Accuracy from NYSEARCH Research

ESTIMATING LARGE LEAKS WITHIN A GAS SYSTEM

The proposed approach looks to identify larger leaks (greater than or equal to 10scfh) quickly, by conducting more frequent or annual surveys targeted at identifying these larger emissions. In this methodology, the accuracy of the technology, noted above, is applied to a scale that is representative of a gas system.

While the NYSEARCH data covered all leak sizes typical of a Gas Distribution network, the overall sample distribution used was different from the distribution found in a gas system. The WSU data was used to get a leak population representative of a gas system.

The WSU data (Figure 2) shows that only a small percentage were greater than 10scfh. By applying this logic to the mobile methane measurement being considered here, only a subset of the leaks that are preliminarily identified as large, or greater than 10scfh, would in fact be large leaks.

To calculate the probability of correctly identifying a large leak using mobile methane measurement within a typical gas system, the uncertainty observed during the NYSAERCH tests must be combined with the actual leak population provided by WSU.

Let us define the two statements:

A: Actual leak is greater than 10 scfh

B: Leak is predicted to be greater than 10 scfh by mobile measurement system.

The probability to correctly identify a large leak as large can be computed using Bayes' law. For this calculation we take the product of the mobile methane detector accuracy $P\langle B|A\rangle$, and the chance of finding a super emitter in a typical gas system $P\langle A\rangle$, and divide that by probability of the mobile methane system identifying a large leak $P\langle B\rangle$ with:

$P\langle B\rangle = P\langle B|A\rangle \cdot P\langle A\rangle + P\langle B|\bar{A}\rangle \cdot P\langle \bar{A}\rangle$ where $\bar{A}$ is the contrary of A, i.e. Actual Leak is less than 10 scfh.

$$P\langle A|B\rangle = \frac{P\langle B|A\rangle \cdot P\langle A\rangle}{P\langle B\rangle} = 39\%$$

With[8]:

Expression	Value	Source
$P\langle B\|A\rangle$	78%	NYSEARCH study
$P\langle A\rangle$	10%	WSU study
$P\langle B\|\bar{A}\rangle$	14%	NYSEARCH study

This value of 39% is much lower than what was observed during NYSEARCH's tests which found that of the 100 leaks predicted as large leaks, 85% of them were validated as being large leaks. This difference comes only from the fact that the probability density of the WSU distribution decreases rapidly for large leaks. Therefore, there is a higher likelihood that a leak identified as being large, is in fact a small leak.

ADJUSTING EMISSION FACTORS

The existing emission factor accounts for emissions from normal and larger leaks. Given that this methodology targets larger emission sources, emission factors must be developed for leaks detected as large (>10 scfh) that will be repaired immediately, and the remaining open leaks, which will no longer account for larger leaks.

Additionally, this adjustment will account for any large leaks that are not detected by the mobile technology.

Calculating the Emission Factor for Predicted Leaks

Using the probability of correctly identify a large leak calculated above, we obtain the average emission factor related to a detection of a large leak as the weighted average of the leak flow rate greater and smaller than 10 scfh:

$$EF_{Average} = \left[P\langle A|B\rangle * [Average\ (x > 10)]\right] + \left[(1 - P\langle A|B\rangle) * [Average\ (1 < x < 10)]\right]$$

In WSU distribution[9] $Average\ (x > 10) = 21.7\ scfh$ and $Average\ (1 < x < 10) = 3.1\ scfh$

The emission factor to be applied to large leaks (> 10 scfh) is therefore:

[8] We only considered the two larger bins: 1 to 10 scfh and greater than 10 scfh, because error during the NYSEARCH tests was greater than a factor of 10 only 2 times among 190 observations greater than 1 scfh.

[9] For this calculation, we have represented the WSU study by a continuous log-normal distribution to avoid bias due to the limited size of the WSU data set: only 5 leaks were greater than 10 scfh. By applying this method, we have reduced the average large leak flow rate from 43.7 scfh to 21.7 scfh while the average flow of medium leaks was not affected at 3.1 scfh.

Accelerated detection and repair of large leaks in a gas Distribution system to reduce methane emissions

$$EF_{Average} = 10.3\ scfh$$

Calculating the Emission Reduction from Repairing Large Leaks

Since the accelerated survey is performed in areas not surveyed through compliance surveys that yeay, a large leak detected through the accelerated process would have otherwise stayed open all year. Assuming that the accelerated survey is performed annually and linearly (see figure 7) during the year the average emission savings is therefore:

$$Saving = EF_L = (EF_{Average} \cdot \frac{8760\,\frac{hours}{yr}}{2}) = 45.2\ Mcf/yr$$

Emissions from Remaining Open Leaks

The other impact of the elimination of the super emitters on system emissions is the adjustment of the emission factors for the other leaks. Using the distribution of leak size reported by Brian Lamb from WSU, we calculate the total emission of the large leaks:

$$Emission\ (A) = \sum_{Leaks>10scfh} Flow(Leak) = \int_{10}^{+\infty} Pdf(flow) \cdot flow \cdot\ dflow$$

$$Emission(A) = 0.36 \cdot Emission$$

Where $Emission$ is the emission of all leaks.

Accounting for Mischaracterized Leaks

The NYSEARCH study observed that 22% of large leaks were mischaracterized as smaller leaks by mobile quantification systems. Such leaks would have not been classified as large leaks by the mobile system.

Therefore, the Emission Factor to apply to the leaks not detected as large leaks is:

$$EF(\bar{A}) = \frac{EF*N*\left((1-P\langle \bar{B}|A\rangle)*\frac{Emission(A)}{Emission}\right)}{N(\bar{A})} = 0.73 \cdot EF.$$

Where EF is the reference EF previously applied to all leaks including large leaks.

N is the total number of leaks

$N(\bar{A})$ is the number of leaks which are not large leaks.

$P\langle \bar{B}|A\rangle = 22\%$

Finally the reduction of emissions is calculated by the following formula:

$$Abatement = (1 - 0.73) \cdot C \cdot \frac{N-N(B)}{N} \cdot Emission - N(B) \cdot 45.2Mscf$$

C is the share of the system that can be surveyed by mobile technology. This factor, smaller than one, accounts for areas that are not accessible.

APPLICATION TO PG&E'S DISTRIBUTION SYSTEM

Summary of 2016 Distribution Leak Data

In 2016, emissions from PG&E's Distribution System accounted for 535 MMscf of methane[10].

In order to apply the leak profile above to identify the emission reductions from the super emitter survey, we must first understand how many of the leaks identified in 2016 were found to be large. The analysis of Picarro's data for the year 201c shows that the number of large leaks detected by the mobile system was around 100 for about 20% of the distribution network covered by the compliance survey (five year survey cycle). Using the formula (1) the total number of large leaks that would be detected on the full system is:

$$N(B) = 100 \cdot \left(\frac{5-1}{2} + 1\right) = 300$$

Additionally, the vehicle mounted mobile system can only access about 7ǫй of PGΘE's gas distribution network.

Applying Large Leaks Identified by Picarro to Unsurveyed Regions

Parameter	Notation	Value
2016 Emissions	Emission	535 MMscf
Number of leaks[11]	N	25,883
Number of detected large leaks	N(B)	300
Coverage by mobile system	C	75%

$$Abatement = 119\ MMscf$$

The number of additional leaks to be repaired will then decrease to 100 in the subsequent years since all territory would have been surveyed annually for large leaks. The emission abatement will then be around 111 MMscf.

[10] 2016 PG&E annual leak report
[11] 2016 PG&E annual leak report

Accelerated detection and repair of large leaks in a gas Distribution system to reduce methane emissions

FIELD VALIDATION

A field validation project was performed in 2017 in collaboration with Picarro and coordinated with PGΘE's compliance survey/The data collected by the mobile system was scrubbed to identify the leaks larger than 10 scfh. When such detection was recorded a team was quickly sent to the location to find the leak and measure its flow rate using a Hi Flow Sampler®. In some occurrences the size and location of the leak triggered an immediate response from PG&E and the leak emission measurement could not be performed.
The rate of detecting large leaks was roughly two per week, in line with the observation made on the 2016 survey data (about 100 per year).

The flow rates measured with the Hi Flow Sampler® were then compared to the values predicted by Picarro.

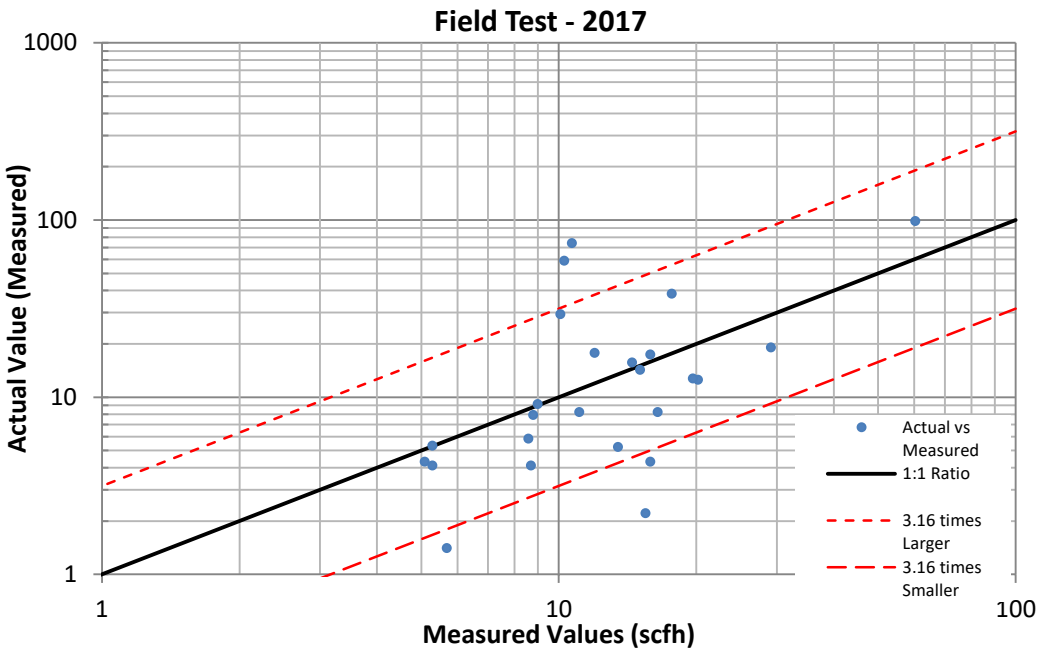


Figure 1: Comparison of leak flow rates predicted by Picarro and measured with High Flow Sampler®

20 predictions among 25 (75%) were within the order of magnitude ($\pm\sqrt{10}$ times the measurement). 11 predictions among 16 were well classified as super emitters (> 10 scfh), i.e. 69%.

The average size of detected large leaks was 22.2 scfh, approximately twice as large as the assumptions made using the methodology proposed in the paper. Given the small sample

size gathered using the 2017 data, the methodology proposed in this paper is conservative, and accounts for this uncertainty.

The observed accuracy of the mobile system used in PG&E territory is in line with NYSEARCH's study findings/ In addition, the proposed model was more conservative than the current results of the field tests and may lead to an underestimate of emission savings from repairing super emitters.

CONCLUSION

Focusing repairs on large leaks in a gas distribution system is potentially a very effective way to reduce methane emissions because their contribution is disproportionally large: Brian Lamb observed in his 2014 WSU study that 54% of methane emission was due to only 2% of leaks.

To capture these emission savings, gas operators must detect and repair large leaks faster than through their safety-driven compliance surveys. Mobile systems are an attractive solution since they can cover an area typically 10 times faster than a foot survey.

However, accuracy of mobile systems to estimate emissions of gas distribution leaks had not been well established until the comprehensive study by NYSEARCH in 2015 and 2016 that compared 3 mobile systems with direct measurement of leak flow rates in controlled settings, as well as in a typical suburban environment. Results showed that 77% of the time prediction by mobile systems was within the order of magnitude of the actual leak flow rate. Similarly, it was shown that 78% of large leaks (>10 scfh) were well classified by mobile systems, and the 22% remaining were wrongly classified as medium leaks (between 1 scfh and 10 scfh).

Using these results and the leak size distribution observed by WSU in 2014, we have shown that we can attribute large leak predictions by a mobile system to large leak and medium leak categories. Based on this attribution the average emission savings from detecting and repairing a large leak can be properly calculated.

Additionally, the emission factor to be assigned to the remaining leaks has been established including the probability for a large leak to be missed by the mobile system.

We have then shown that the methane emission abatement to be expected from the PG&E system by accelerating the detection and repair of large leaks can be estimated to be 119 MMscf per year (about 22% of emissions) with about 300 additional repairs (about 4% of the total number of leak repairs) for the first year and 111 MMscf per year with about 100 additional repairs in the following years.

The field validation performed in 2017 in collaboration with Picarro confirmed the number of additional repairs to plan for and the overall accuracy of the mobile system in line with NYSEARCH's results/ Direct measurements also showed that the calculation method was conservative.

Accelerated detection and repair of large leaks in a gas Distribution system to reduce methane emissions

Accelerated detection and repair of large leaks in a gas Distribution system to reduce methane emissions

Appendix

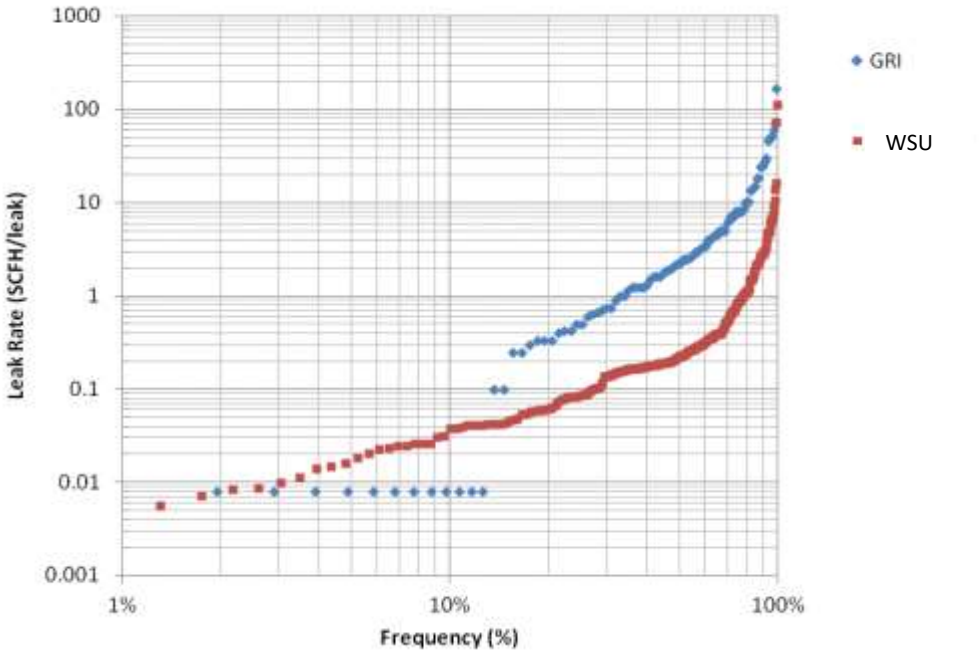


Figure 2: Distribution of leak flow rates measured by GRI in blue and WSU in red

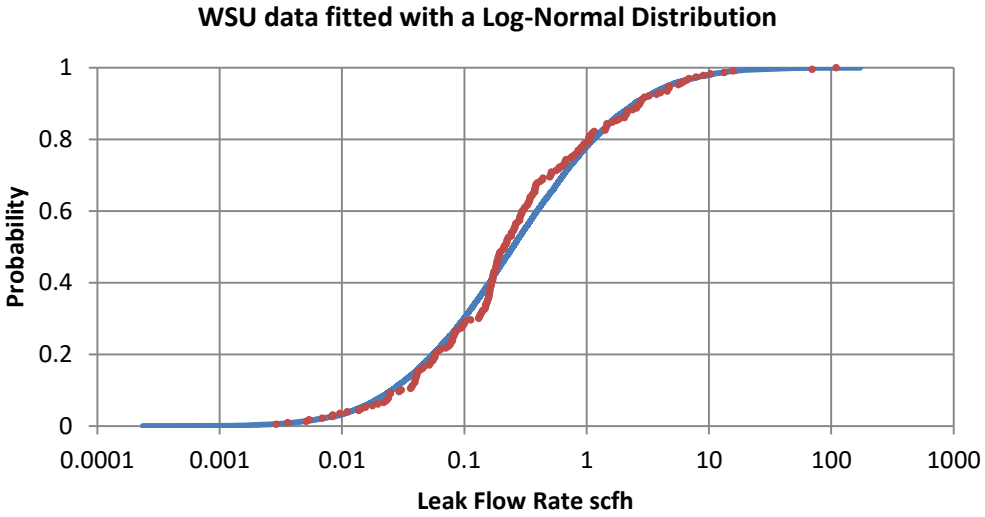


Figure 3: WSU data fitted with a Log-Normal Distribution

		Emission Factors		
Pipeline	Material	GRI	WSU	
Mains	Cast Iron	27.25	-	scf/mile
	Unprotected	5.91	2.40	scf/leak

	Steel	2.32	3.79	scf/leak
	Plastic	11.39	1.04	scf/leak
Services	Unprotected Steel	2.31	1.02	scf/leak
	Protected Steel	1.05	0.40	scf/leak
	Plastic	0.27	0.40	scf/leak
	Copper	0.88	0.88	scf/leak

Table 2: Emissions Factors from GRI's and WSU's studies

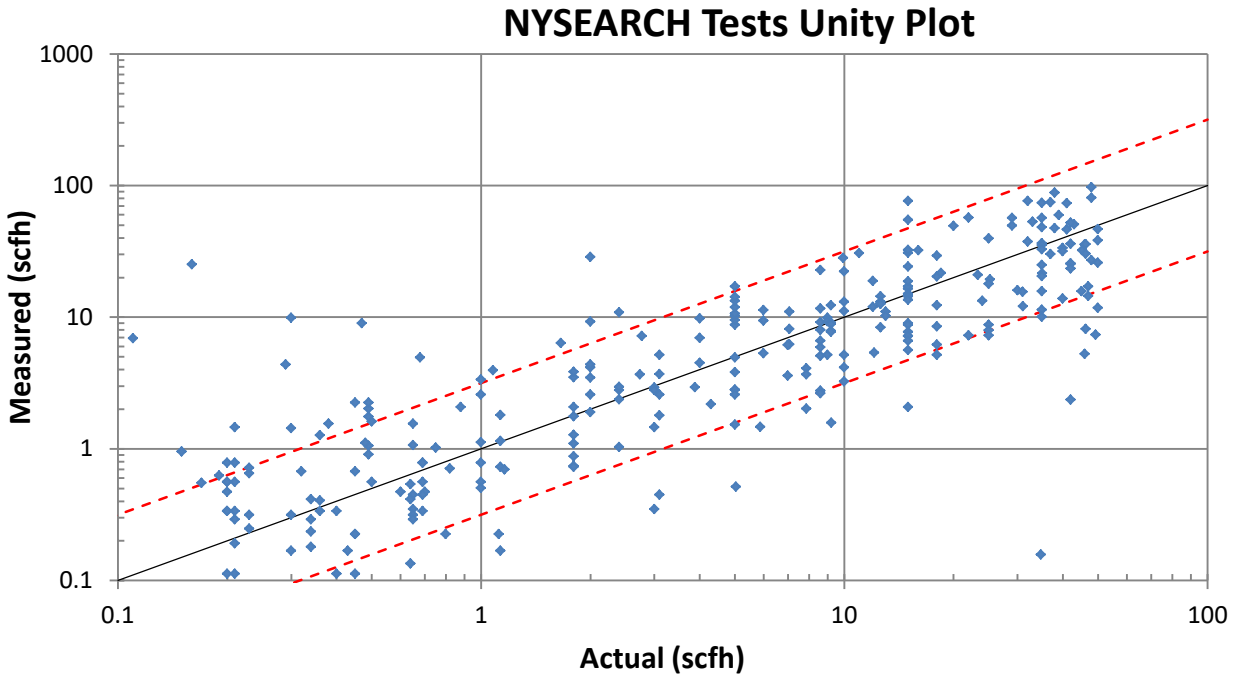


Figure 4: Unity plot of all NYSEARCH study results

The error of prediction by the mobile quantification systems was defined as:

$$error = \left| Log_{10}\left(\frac{Actual}{Predicted}\right)\right|$$

Its Probability Density Function was fitted with a Weibull function as displayed on figure 2. The peak of the curve or the highest probability is when $error = 0.373$ stating that Predictions are most often 2.4 times larger or smaller than Actuals. In addition, the order of magnitude limit, as defined above, corresponds to the vertical line: $error = 0.5$.

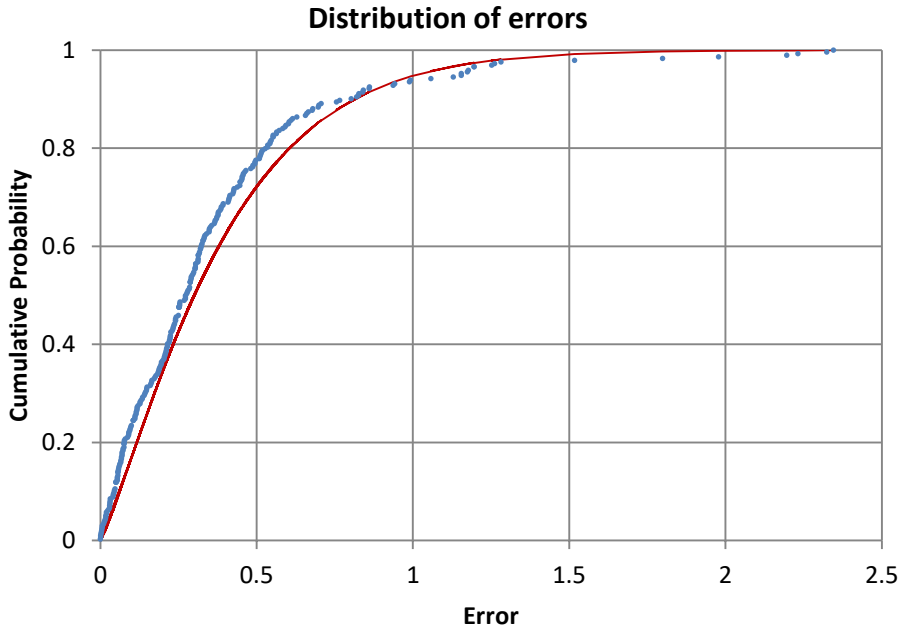


Figure 5: Error Distribution Function for NYSEARCH Study Data fitted with a Weibull function (Tests performed by PG&E and Picarro on above ground leaks showed similar results.)

Accelerated detection and repair of large leaks in a gas Distribution system to reduce methane emissions

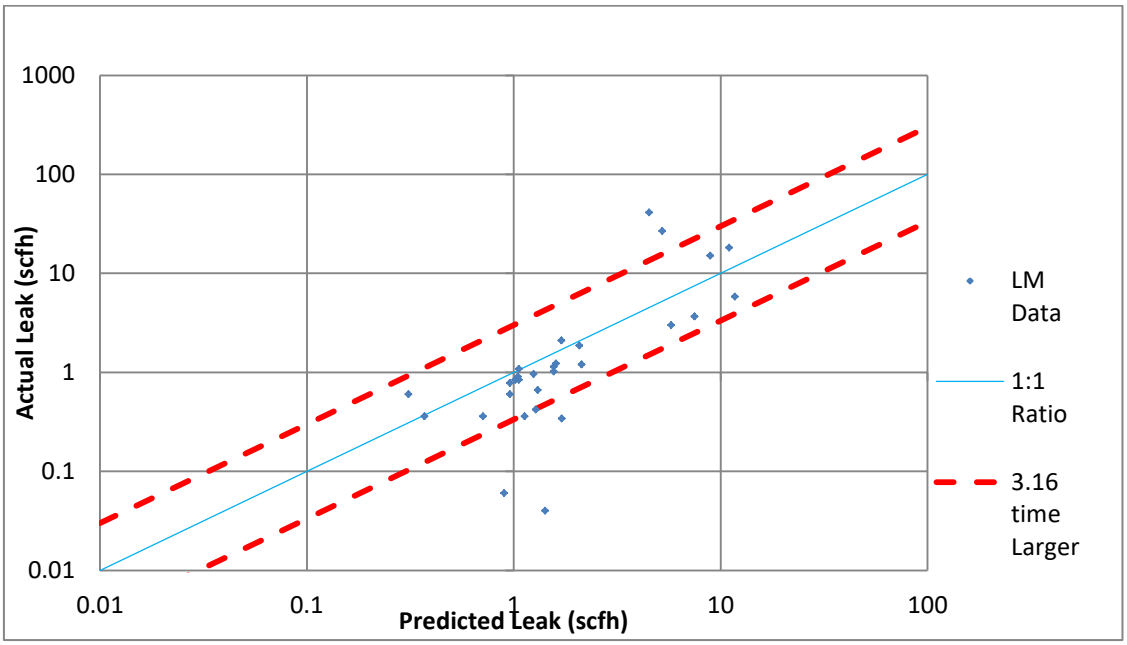


Figure 6: Unity plot of predictions and direct measurements performed in 2017 at Los Medanos using Picarro's mobile leak quantification system/

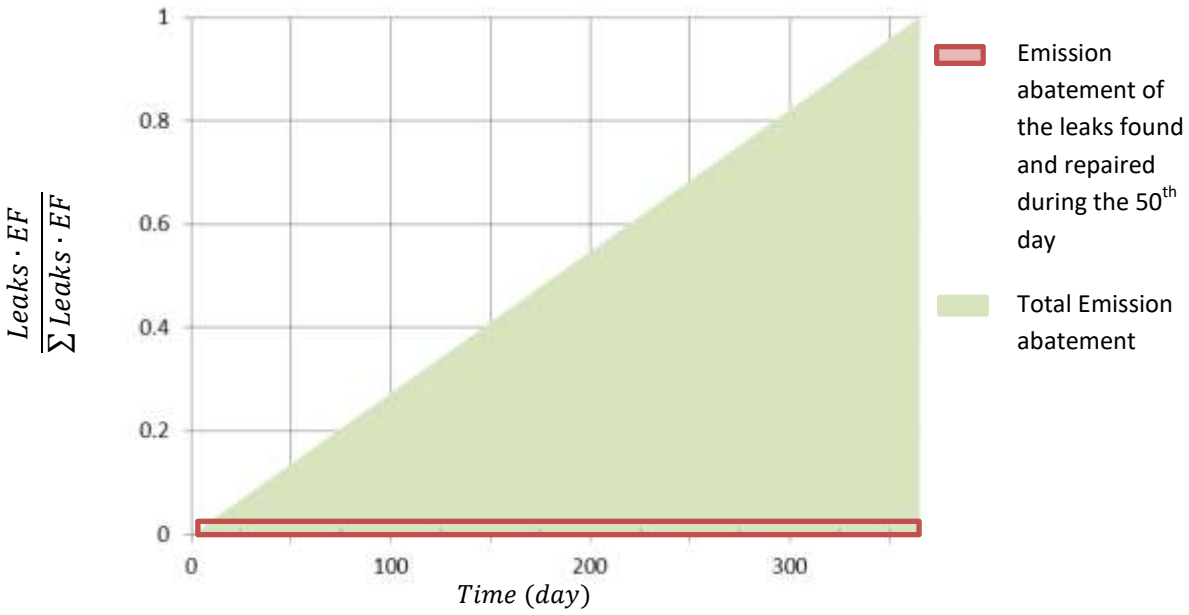


Figure 7: Emission abatement for leaks found (linearly during the year) and repaired immediately.

Calculation of the annual savings for BP 21

Super emitters:

Abatement in 2018: 119 MMscf

Abatement in 2019 (compared to a base line without Super Emitters of year 2018 repaired): 129 MMscf

Average abatement per year: 124 MMscf = 0.124 BCF

Grade 3 leak repair:

Grade 3 repairs	2018	2019
Expense	1430	1400
Capital	556	544
Total	1986	1944

Average emission factor: 2.21 scfh = 19.4 Mscf/year

Abatement in 2018: 19 MMscf

Abatement in 2019: 51 MMscf

(Calculated with consideration that the leaks repaired in 2018 would have stayed open the full year multiplied by (1-30%) to take into account the fact that 30% of them would have been eliminated by baseline attrition. For the leaks eliminated by baseline attrition, the abatement corresponding to half a year is added because considering that they would have been eliminated linearly along the year. These two contributions are added to the abatement due to the 2019 repair of Grade 3 leaks.)

Average abatement per year: 35 MMscf = 0.035 BCF

Total BP 21 average annual abatement: **0.159 BCF**.

PART 1: OVERVIEW

a) Best Practice: 22

b) Status: Complete with continuous improvement R&D

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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E has a robust and programmatic system for updating its standards and procedures around pipe fitting specifications which exceed American Society of Mechanical Engineers (AMSE) standards. The program includes continuous evaluation of tools, technology and procedures to address changes in code and compliance.

The following guidance documents currently have steps to identify and repair leaks during routine maintenance:
TD-6100P-02, “Gas Leak and Odor Investigation”
TD-6100P-25, “FE Regulator Installation and Operation”
TD-4126P-04, “Electronic Pressure Recorder Maintenance and Calibration”
TD-4430P-02, “Gas Transmission Stations Inspection, Testing, and Maintenance Procedures”
TD-4430P-04, “Gas Valve Maintenance”
TD-4300P-05, “Performance Check and Maintenance of Rotary Gas Meters > 1000 CFH”
TD-4520P-01, “Installation and Commissioning of Maintained Numbered and Lettered Valves”
TD-4530P-02, “Electronic Corrector Installation and Maintenance”
TD-4530P-03, “Gas Meter Change and Removal Procedure for Large Meters and Meters Operating over 2 PSIG”
TD-4530P-11, “Meter Maintenance Requirements: Greenhouse Gas, Fuel, and Operational”
TD-4540P-01, “Maintenance of Regulator Stations”
TD-4540P-02, “Maintenance of Gas Regulation Equipment on Meter Set Assemblies”
TD-4540P-03, “Maintenance of Farm Tap Regulator Sets”
TD-4545P-01 through TD-4545P-10, “Control Valve System Maintenance”

H-10 includes the HPR pre-fab design which replaces many threaded connections shown in older legacy designs with socket welded connections greatly reducing leak potential. The pre-fabs were first ordered in 9/2015. The following units have been ordered to date: 2015 = 200 units, 2016 = 160 units, 2017 = 2,320 units, 2018 = 760 units. PG&Eanticipate an average order of 1,000 units each year to 2020.

Prefabricated meter set risers from Lyall have aluminum rich urethane applied to the base of the riser valve and heated. This allows the material to form a better seal below the riser valve. This is in addition to the thread sealant that is applied. Perfection risers utilize a similar sealant solution. These superior thread sealants lead to reduced leaks on meter sets.
See the supplemental section below for additional details.

b) Alternative Proposal to BP or exemption?
None.

c) Proposed Plan:
PG&E proposes to utilize its existing programmatic system for pipe specifications as it includes a continuous improvement component that incorporates new tools, technology and procedures to address changing code and compliance.

Guidance Documents will continue to look into pre-fab opportunities that will reduce the number of threaded connections.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?
There is no overlap with other regulations.

e) What technology is required to implement the best practice and why?
There is no technology required to implement this best practice, however, PG&E will look to incorporate new technology as it becomes available.

f) Will work require additional personnel and/or contract support? If so, please provide details.
No additional resources are needed.

g) What changes to existing operations are required? How will those changes be implemented?
No changes to existing operations are required at this time.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.

As part of PG&E's program, the following are the most recent activities specific to this BP:

- New utility procedure TD-4160P-72, "Seal Welding";
- Potential modification of EMS 5020, "Steel Threaded Pipe Nipples, Gas Meter Assemblies Meter Nuts, Forged And Malleable Iron Threaded Gas Fittings" to revise thread quality requirements;
- Potential revision of Supplier Quality receiving inspection job aids to ensure adequate thread quality; and
- Revision of Utility Procedure TD-4150P-110, "Continental Steel to PE Mechanical Bolt-on Saddle Punch Tee" to add the following:
    - "IF saddle punch will be abandoned in place,
    - THEN weld cap to tee outlet" to avoid threaded component being backfilled.

i) Timeline for implementation (Milestones):
TD-4160P-72 will be published in March 2018.
TD-4150P-110 will be published in April 2018.
The remaining BP tasks described are currently in place.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
Cost effectiveness has not been evaluated at this time.

k) Identify any cost benefits from this BP, when cost estimates are known:
Cost benefits are unknown at this time.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
The benefits from this BP are not expected to overlap with other BPs.

m) Anticipated Emissions Reductions from this BP:
Emissions reductions are still to be determined.

2015 Baseline Emissions affected, where known:
NA

n) Calculation Methodology:
See response to m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
GTI/CARB study for meter set leaks in California (surveying 500 residential meter sets in CA), as described in the attached document (BP22_ATCH01). This study is currently being performed. Other studies also include:

- NYSEARCH project to reduce methane emissions at threaded connections (BP22_ATCH02)
- OTD project to identify spray-on or brush-on leak seal for meter set joints (BP22_ATCH03)

d) Other:
See the list of procedures and documents referenced above.

Pacific Gas and Electric Company

Greenhouse Gas Emissions from Residential Gas Meters: Field Study

Customer Information Sheet

California Air Resources Board (CARB) is sponsoring a California field study to better understand greenhouse gas (GHG) emissions from residential gas meters. The Gas Technology Institute (GTI), a research organization, will be conducting GHG emission measurements within the service territories of three major California utilities; Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), and San Diego Gas & Electric (SDG&E).

The field measurements will begin on October 16th, 2017 for a period of one week at PG&E in the cities of Fremont, Fairfield, San Ramon, and Pacifica. The researchers will take GHG measurements at selected residential gas meters.

The research team has carefully selected sites within each city that meet specific criteria to ensure that the emissions data collected is comprehensive and representative of that area.

PG&E, SoCalGas, and SDG&E are supporting this study. GHG emissions data collected in this study will be reported to CARB.

For more information, please contact:

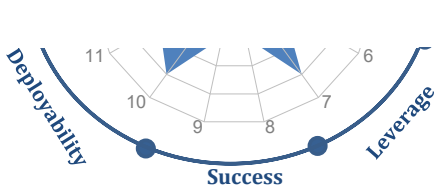
Pacific Gas and Electric Company
Gerry Bong (925) 244-3885

California Air Resources Board
Winardi Setiawan (916) 324-0337

Gas Technology Institue
Kristine Wiley (847) 387-9397

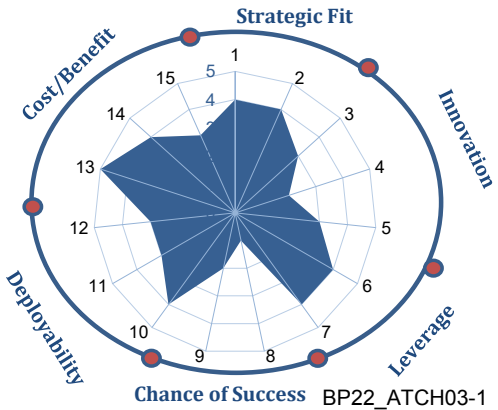
Project: **NYSEARCH - Reducing Methane Emissions at Threaded Connections - Sampling Program**

	Key criteria for assessment	Comments	Score (0 - 5) 0 is bad 5 is excellent
Strategy	What issue(s) does it solve?	In California, threaded connections from meter sets, and M&R stations are reported to account for up to 45% of distribution system methane emissions. In 2017, CPUC came up with a list of best practices as part of SB 1371 and Best Practice (BP) 22 calls for California utilities to review and revise pipe fitting specifications and potentially roll out a pipe fitting replacement program. One notion is that switching from the current National Pipe Thread (NPT) specification (ANSI B-1.20.1) to the more precise aeronautical grade specification (ANPT -AS71051) will improve fit and reduce leakage. Though, no studies have been done to prove this theory. This project will evaluate the impact of changing the thread specifications relative to alternative measures such as using better sealants and tightening standards of NPT conformance. Deliverable of the first phase (12 months) is a report outlining the types of fittings funder companies use, the ratio fittings that meet NPT spec vs. ANPT spec, and results of leak test of the fittings.	5
	How does it fit in our overall strategy and rank among our priorities?	It is part of our mission to deliver clean energy to our customers. This project is well aligned with this and addresses a regulatory requirement to implement/research the best practices proposed by CPUC through SB 1371.	5
Innovation	What is the state of the art?	Gas companies use a large number of threaded fittings. While some threads are straight for unions or meter nuts where a gasket is used, most threads are tapered to the National Pipe Taper (NPT) thread specifications (also known as ANSI B1.20.1). At PG&E we require our threading to be in compliance with ANSI/ASME B1.20.1 (refer to document B-11, B-12, B-13, B-14, B-15). The Aeronautical Pipe Taper (ANPT) requires measurement and higher precision of several dimensions of the thread taper than the NPT standard. To check a fitting thread for conformance to NPT or ANPT require test gages. NPT only requires two "Pass/Fail" gages, while ANPT requires six.	3
	What is the existing solution at PG&E?	At PG&E we require our threading to be in compliance with ANSI/ASME B1.20.1 (refer to document B-11, B-12, B-13, B-14, B-15)	3
	How does the team compare to competition?	NYSEARCH identified Campbell Consulting because of the experience that its principal, Bruce Campbell, has had with gas industry components and tools as well as testing programs. Bruce has a proven track record in product development and testing and evaluation.	4
Leverage	How does the project leverage previous work?	We are unaware of past work on this specific topic that can be leveraged.	2
	What are the opportunities of co-financing?	It is a NYSEARCH project supported by a group of utilities. The cost of this first phase is $103k, PG&E contribution would be of $21k for a leverage ratio of 4.9.	4
Chance of Success	What are the risks for failure?	As identified by Bruce Campbell, many other factors can influence the occurrence of a leak including improper installation, fatigue and aging issues of the fitting seal, and ineffective thread sealant. It will be difficult to decouple thread spec from these other factors and will take many experiments and a lot of time to accomplish.	2
	What are the requirements for deployment at PG&E?	There is no requirement for PG&E to reap the benefit of this study. The results can be disseminated to our subject matter experts for consideration.	2
Deployability	How will the solution be used?	The results of the study will inform us on different methods to prevent leaks at threaded fittings. This first phase looks at thread spec while the next phases of the project will analyze the effect of thread sealants and other factors.	4
	What additional delays have to be accounted for the full deployment?	Delays are expected when there is a large variety of fittings (size, type, vintages) to test. The long- term testing will take up some time as well.	3
	How does it synchronize with existing actions?	This project is well aligned with our efforts to reduce emissions from the gas transmission and distribution system including reducing volume of blowdowns, studying emission rates at regulating stations, and using better leak survey technologies to find more leaks.	5
Cost vs Benefits	Can we assess cost benefits of the solution?	In 2016, California reports ~3 Bcf of methane emissions (165,000 ton of CO2 equivalent) from meter sets and distribution regulating stations (this is calculated using standardized emission factor but we think the leaks are mostly at threaded fittings). The value of gas lost is roughly $10 million ($3.30 per Mcf). Ultimate cost associated with methane emissions would be a tax on greenhouse Gases. Using a tax of $15 of ton of CO2 equivalent, the tax cost would be $2.5 million per year. Replacing every single threaded fitting in the company might incur an exorbitant cost which is not practical. This study will help us understand the cost benefit.	4
	What will the on-going cost of the solution after deployment be?	Characterization of various factors affecting leaks at threaded fittings may lead to changes in the way we do work	3
	What is an acceptable cost target for PG&E?	The expected cost of ~$25k for the first phase is inexpensive relative to the potential benefit.	4
		Average score	3.5


11
6
10
7
9
8
Deployability
Leverage
Success

2017 Fall OTD project proposal (5.18.a): Spray-On Leak Seal for Meter Set Joints

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	Many studies have established that a large percentage of leaks at meter sets occur at threaded joints between components. Most of the time the leaks are so minor that they only produce small bubbles when a soap solution is applied. To repair these leaks, the meter set has to be dismantled and the joint re-sealed or replaced which is very time consuming and costly. This project will identify possible spray-on or brush-on solutions to seal minor thread leaks on meter set assemblies that do not require dismantling the meter set. The deliverable is a final report with the strengths and weaknesses of evaluated leak seal systems.	4
	How does it fit in our overall strategy and rank among our priorities?	This project will benefit PG&E's vision to meet the challenge of climate change by providing a practical and inexpensive method to seal non-hazardous emissions from meter set leaks. This project will aid our efforts to comply with new regulations such as SB 1371 which calls for elimination of leaks through implementation of better materials, detection, and mitigation approaches.	4
Innovation	What is the state of the art?	There are also combinations of seal putty, tape and wrap that can be applied as a permanent leak repair method. One such product is Stop It from InduMar Products Inc. These products can be applied to the leaking fitting in live or non-live conditions. We are not aware of products that can be quickly sprayed or brushed to fix small leaks.	3
	What is the existing solution at PG&E?	According to TD-4100P-05, to fix a leak at a riser thread, PG&E crew would first attempt to tighten the valve (maximum of one turn). If that fails to stop the leak, replacement of the valve and application of new thread sealant are the next actions. When the riser threads arein poor condition (e.g. corroded), the crew can cut off the old threads and cut new threads into the riser. In addition, the DIMP team is also researching the use of seal putty and tape wrap as quick repair solutions for leaks.	2
	How does the team compare to competition?	GTI has experience researching leak repair methods for steel pipes and have good visibility on the products in the market that can be tested for this project.	3
Leverage	How does the project leverage previous work?	OTD completed a project in 2016 to look into permanent repair methods for leaks on above ground piping. They tested the performance and longevity of four products (wraps and resins). The winning product would not meet the requirement of this project since it requires non-live condition. Using knowledge from the project, OTD may be able to propose a solution.	4
	What are the opportunities of co-financing?	The total cost for this 16 months project is $129,200. Assuming 5 utilities will fund the project, the shared cost for PG&E is roughly $26,000.	4
Chance of Success	What are the risks for failure?	There is a high risk of failure since the solution will be a new category of products that do not exist in the market. Chances are follow-up phases to develop a product is needed.	1
	What are the requirements for deployment at PG&E?	Once a promising product is identified, PG&E has to further evaluate the product internally and develop training and OQ protocols, publish new standards for the field crews to utilize the product.	2
Deployability	How will the solution be used?	This project will deliver a final report with testing results of different products. PG&E can use this to further test promising products.	4
	What additional delays have to be accounted for the full deployment?	Delays are expected from commercialization of the product if nothing exists in the market.	3
	How does it synchronize with existing actions?	This project synchronizes with PG&E's effort to minimize emissions from the distribution system by reducing leak backlogs.	3
Cost vs Benefits	Can we assess cost benefits of the solution?	The potential benefit of having a quick solution to repair minor thread leaks is very significant. There is currenty no cost effective solution to repair small leaks if tightening, lubrication and adjustment do no work. Assuming that 5% of our meter sets have minor leaks, the savings from using this approach is 5% * 4 million meter sets * $500 savings/meter repaired = $100 mil.	5
	What will the on-going cost of the solution after deployment be?	There will be no ongoing cost associated with deployment of the results.	4
	What is an acceptable cost target for PG&E?	$30k is an acceptable cost for PG&E considering the potential cost savings and benefit this project have in helping us meet climate change regulations.	3
		Total	**3.3**



PART 1: OVERVIEW

a) Best Practice: 23 **b) Status:** Pilot

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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

Historically PG&E reduced methane emissions at the Compression & Processing (C&P) and M&C stations opportunistically. Examples include the installation of electric/hydraulic actuators that have no emissions at gas terminals, and installation of Becker controllers that are classified as no bleed devices within M&C, as well as C&P facilities. Where feasible, compressed air is used as a control gas to eliminate the need of natural gas(e.g., the Milpitas Terminal uses air for regulating valve controllers).

As defined in the California Air Resources Board (CARB) Oil and Gas Ruling requirements, PG&E is replacing the high bleed controllers at C&P Stations and underground storage facilities.

PG&E has also been replacing the high bleed pneumatic devices at the M&C Stations as part of the Complex Station Rebuild program outlined in the 2019 GT&S work plan. In 2017, five Bristol controllers and two Fisher 3560 positioners were replaced. PG&E will continue to replace the high bleed devices as part of the station rebuild program.

b) Alternative Proposal to BP or exemption?

None

c) Proposed Plan:

PG&E has existing programs in place for systematically replacing the aging and obsolete equipment at both the gas transmission Compressor and Measurement & Regulation Stations. Replacing the aging controllers to address obsolescence also has an added benefit of reducing the overall stations emissions.

For Transmission Compressor Station Facilities:

As part of the CARB ruling, PG&E plans to address all remaining high bleed devices at the C&P station and underground storage facilities to intermittent or air before January 2019. The planned high bleed pneumatic device retrofits in 2018 at the C&P and storage facilities are 7 and 105 controllers, respectively.

PG&E has reciprocating compressors that are currently depressurized when placed in standby. In 2018, PG&E is retrofitting two of these compressors to allow them to safely remain pressurized while in standby, substantially reducing the number of blowdowns annually. An additional three compressors will be retrofit pending approval of the 2019 Gas Transmission & Storage (GT&S) rate case.

For Transmission Measurement & Control Station Facilities:

PG&E plans to remove the high bleed devices (Bristol controllers, Moore 74G and Fisher Positioners) at M&C facilities and replace them with a low bleed device. If the controller is installed on an obsolete actuator and plug valve, then it will be replaced with a new ball valve and an actuator.Most of the high

bleed devices will be removed and replaced during the complex station rebuilds, routine capital work such as valve replacements or when stations are decommissioned as outlined in the 2019 GT&S work plan. The planned high bleed controller replacements as part of the M&C station rebuild scope for 2018-2019 and 2020-2021 are 8 and 21, respectively.

In addition, PG&E is supporting an ongoing research project at Operations Technology Development (OTD) to evaluate commercially available slam-shut regulators for installation in confined spaces. Once installed the new regulators will minimize vented emissions from meter sets. Refer to attachment for more details.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?
The replacement of high bleed devices at C&P stations and underground storage facilities are being addressed as part of the CARB Oil and Gas ruling. There are no incremental requirements associated with this BP.

e) What technology is required to implement the best practice and why?
None.

f) Will work require additional personnel and/or contract support? If so, please provide details.
None. This work will executed utilizing existing programs and projects.

g) What changes to existing operations are required? How will those changes be implemented?
No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
None.

i) Timeline for implementation (Milestones):
For Transmission Compressor Station Facilities:
2018: Replacement of 7 controllers at C&P stations and 105 controllers at underground storage facilities.
2019-2020: Retrofit/Replacement of three compressors pending approval of the 2019 GT&S rate case.

For Transmission Measurement & Control Station Facilities:
2018-2019: Replacement of 8 controllers addressed as part of the station rebuilds.
2020-2021: Replacement of 21 controllers will be addressed as part of the station rebuilds and retirement.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
No costs are associated with this BP.

k) Identify any cost benefits from this BP, when cost estimates are known:
The abatement of 18.4 MMcf/y as calculated in m) will lead to cost saving of $ 61k/y corresponding to the average value of gas at City Gate (Average PG&E City Gate price in 2017: $3.304 per Mscf).
.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?

See question j) above.

m) Anticipated Emissions Reductions from this BP:
Emission factors from Appendix 09 of the annual leak report for Leak Abatement OIR were used to characterize high-bleed controllers (18.6 scfh), intermittent bleed controllers (2.4 scfh) and low-bleed controllers (1.4 scfh). For the emission calculation, new intermittent low-bleed controllers are assigned the emission factor of low-bleed devices.

The difference between the emission factors of the existing device and the replacement device is the benefit of installing a new controller. In 2018, approximately 120 new controllers (116 high-bleed and 4 intermittent bleed) will be removed or replaced at C&P, storage, and M&R facilities. The replacements are approximately 46 low-bleed and 18 no-bleed devices. When all the devices have been removed or replaced, the total yearly emissions reduction is around 18.4 MMscf per year.

2015 Baseline Emissions affected, where known:
The 2015 emissions from transmission M&R stations and components at storage facilities are 579 MMscf and 10.6 MMscf respectively.

n) Calculation Methodology:
See section m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

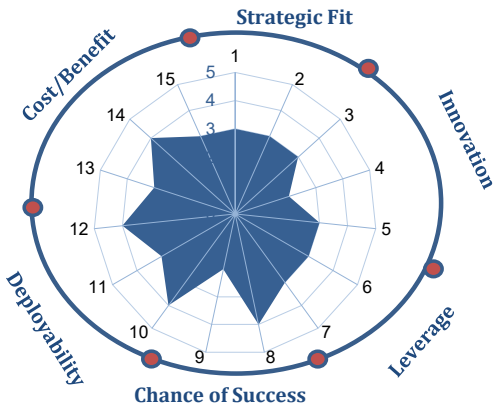
b) Changes to Operations:
None.

c) Research or Studies:
See attachment of OTD project on non-traditional gas regulators (BP23_ATCH01).

d) Other:
None.

2016 Fall OTD project proposal (5.17.e): Non-traditional Natural Gas Regulators - Slam shut and Vent Limiting regulators

	Assessment Question	Qualitative Evaluation	Rating
Strategy	What issue(s) does it solve?	It can be difficult to find a safe location to install a meter set regulator or to run a vent pipe to safe locations. Slam shut regulators enable reduction in gas pressure without the need to vent gas to the atmosphere. Whereas vent limiting regulators limit the amount of gas that is released to safe levels. OTD will examine the operations, applications, limitations of slam shut and vent limiting regulators for potential broader use in the gas industry. These non-traditional regulators may enable placement of meters and regulators at locations that are traditionally deemed unsafe. In addition, the methane emissions from regulators will be lowered.	3
	How does it fit in our overall strategy and rank among our priorities?	This project will benefit PG&E's effort to mitigate risks with meter vents and locations with openings into buildings (windows, AC units, dryer vents). We are currently working to approve a slam shut regulator for efforts around the issue and additional participation would be beneficial.	3
Innovation	What is the state of the art?	Slam shut regulators and vent limiting regulators are state-of-the-art technologies in eliminating or reducing gas vented from traditional regulators.	3
	What is the existing solution at PG&E?	PG&E has been looking at the vent limiting and slam shut regulators for some time. The DIMP team has installed a couple hundred of Pietro Fiorentini FE slam shut/vent limiting regulators (for single family home meter sets) for a field trial and are in the process of approving the model for systemwide installations.	2
	How does the team compare to competition?	GTI has in-house experts on gas regulators and can provide guidance on how to compare the various brands and models.	3
Leverage	How does the project leverage previous work?	This project will leverage the lesson learned and experiences of other utilities in using slam shut and vent limiting regulators.	3
	What are the opportunities of co-financing?	The total cost for this 12 months project is $76,000. Assuming 5 utilities will fund the project, the shared cost for PG&E is $15.2k.	3
Chance of Success	What are the risks for failure?	There is no risk of failure since the project mainly involves data gathering, survey and reporting.	4
	What are the requirements for deployment at PG&E?	The information from this project can be used directly by the DIMP program.	2
Deployability	How will the solution be used?	The project findings will be used by DIMP to inform their selection of slam shut/vent limiting regulators for single family homes and commercial buildings.	4
	What additional delays have to be accounted for the full deployment?	To be able to deploy a specific brand and model of regulator, PG&E will have to perform a field trial and approve the regulator.	3
	How does it synchronize with existing actions?	This project synchronizes with PG&E's DIMP effort to install more slam shut regulators to mitigate risks with meter vents and locations.	4
Cost vs Benefits	Can we assess cost benefits of the solution?	This study will inform us with information. The cost of $15.2k is reasonable consiidering that the other members can glean from this study too.	3
	What will the on-going cost of the solution after deployment be?	There will be no ongoing cost associated with deployment of the results.	4
	What is an acceptable cost target for PG&E?	$15.2k is an acceptable cost for PG&E considering the impact this project has on meter set safety.	3
		Total	**3.1**



PART 1: OVERVIEW

a) Best Practice: 24 **b) Status:** Complete

Dig-Ins / Public Education Program

Dig-Ins – 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.

PART 2: BEST PRACTICE DETAILS

a) Historic work: PG&E has a comprehensive public awareness program that consistently exceeds regulatory requirements in the area of "Call before you dig." Part of the program is the "811 Ambassador Program," which offers financial rewards to employees who identify contractors digging without an Underground Service Alert (USA) ticket.

Second, PG&E provides in-person safe excavation trainings, free of charge to the public. PG&E increased the number of these classes from 35 in 2015 to 100 in 2016, and 200 in 2017. PG&E's "Dig-in Reduction Team (DiRT) teaches the classes. Audiences are identified through USA ticket submittals and excavators that cause damage to PG&E's facilities.

Third, PG&E maintains a "safe digging" website to provide instruction to excavators on safe digging practices. This information is delivered to excavators in email messaging and social media outreach.

The 811 Ambassador was piloted internally in 2015, had roughly 1,000 calls in 2016, and expanded to 4,000 calls in 2017.

The result of these three programs in 2017 was a three percent reduction in "no-call" damages (damages cause where there was no valid USA ticket), amidst an increase in USA tickets and construction activity overall.

b) Alternative Proposal to BP or exemption?
None.

c) Proposed Plan:
PG&E's plan is to allow its existing Public Awareness (PA) program to meet the requirements due to the 2017 growth in the 811 Ambassador program, and the additional extra education programs delivered by the DiRT team. See the supplemental section below for additional details.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?
There is no overlap with other regulations, however, both the 811 Ambassador Program and the education programs delivered by the DiRT team are beyond the public awareness regulations that govern PG&E gas transmission and distribution systems.

e) What technology is required to implement the best practice and why?
No additional technology is required.

f) Will work require additional personnel and/or contract support? If so, please provide details.
No additional resources are required.

g) What changes to existing operations are required? How will those changes be implemented?
No additional changes are required as all changes have been implemented.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.
No new procedures or changes need to be made to the existing Pipeline Public Awareness Plan. See the supplemental section below for additional details.

i) Timeline for implementation (Milestones):
Compliance with this BP is complete.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:
No costs are associated with this BP.

k) Identify any cost benefits from this BP, when cost estimates are known:
The abatement of 3.1 MMscf/y as calculated in m) will lead to cost saving of $ 64k/y corresponding to the WACOG of the 2018 Illustrative Gas Supply Portfolio: $2.05/therm.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
See question j) above.

m) Anticipated Emissions Reductions from this BP:
In 2017, there is a 3% reduction in the number of "non-call" dig-ins compared to 2016 (despite the increase in construction activities). The percent of non-call dig-ins is 51% of all dig-ins. Therefore, with the assumption that the trend continues, the yearly reduction in emissions is roughly 1.5% or 3.1 MMscf (using 2015 numbers as baseline).

2015 Baseline Emissions affected, where known:
In 2015, emission from distribution dig-ins is 127 MMscf while emission from transmission dig-ins is 81 MMscf. The total is 208 MMscf.

n) Calculation Methodology:
See section m) above.

o) Additional Comments:
None.

p) Overlap with Safety: The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that could result, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:

None.
c) Research or Studies: None.
d) Other: See the attached for PG&E's 811 Ambassador web page (BP24_ATCH01), PG&E's call before you dig web page (BP24_ATCH02) and the Pipeline Public Awareness Plan (BP24_ATCH03).

811 Ambassador Program

811 Ambassador Program

Every year, failure to call before digging results in more than 200,000 preventable hits to underground utility lines nationwide. These unintentional hits to underground utility lines can cause serious injuries, disrupt service to entire neighborhoods and potentially result in fines and repair costs.

Calling 811 connects homeowners and contractors to Underground Service Alert (USA), which provides a free service that notifies utility companies about any type of excavation project. Professional locators are sent to the requested digging site to mark the approximate locations of underground lines with flags, spray paint, or both.

Everyone—All PG&E employees, contractors, landscapers, and customers—must call 811 before digging for any project, large or small. This includes simple landscaping like planting trees or shrubs, to building a deck, installing a rural mailbox, or putting up a fence to cleaning up after a natural disaster or storm.

The 811 Ambassador Program exists to equip PG&E's 23,000 employees and contractors to take corrective action against unsafe excavation, and to educate others on the importance of "811 Call Before You Dig.

What Can I Do To Help?

Be an 811 Ambassador and do your part to keep your neighborhood safe, reduce dig-ins, and promote the Company-wide goal of safety. **Here's how YOU can make a difference:**

- If you observe digging taking place with no markings, call **PG&E Damage Prevention at (925) 328-5560** to report the location. All calls where the excavation is confirmed to be "No USA," indicating that 811 was not called before digging, will count toward your total number, and you will receive a gift card at the end of the quarter, the amount based on a tiered system:
  - 1-4 confirmed calls in one quarter = $20 Amex gift card
  - 5-9 confirmed calls in one quarter = $50 Amex gift card
  - 10-29 confirmed calls in one quarter = $100 Amex gift card
  - 30+ confirmed calls in one quarter = $200 Amex gift card

  Additionally, the division with the most calls each quarter will receive a special division reward recognizing that achievement. ***This is an internal PG&E employee incentive only.***

- Share the important safety message of "811 Call Before You Dig" with your community at a block party, HOA meeting, or simply in a conversation with your neighbors, and you will be entered into a drawing to win a flat screen TV and Blue-Ray player! For complete instructions on participating in **811 Ambassador: "It's My Neighborhood"**, click here. ***This is an internal PG&E employee incentive only.***

- Take the official 811 Ambassador Pledge, denoting a 3-part commitment to: 1) Personally adhere to safe excavation practices as detailed in California Government Code 4216, 2) Educate others on the importance of 811 as the opportunities naturally arise in everyday life, 3) Take corrective action in situations where unsafe excavation is observed, using resources provided through the **811 Ambassador Program**. To take the pledge, simply complete the 811 Ambassador Pledge Sheet.

Download this Five Minute Meeting to spread the word on this program to your teams.

If you have any questions, please contact Program Manager Kaci Piccillo at k1pm@pge.com.

MENU

EMERGENCIES

YARD SAFETY DIGGING SAFETY CALL BEFORE YOU DIG!

Watch a short video to learn about digging safely.

GO TO VIDEO

Avoid digging into underground pipelines

Safety is our highest priority at PG&E. To ensure that you remain safe when doing any digging projects, always call 811 first. 811 is a free service managed by Underground Service Alert and available to everyone. After you call, Underground Service Alert will contact PG&E and other companies that have underground lines in your area. Representatives will then mark the location of their underground lines so you can avoid them and dig safely. Whether you are planting a tree or a garden, or digging holes for fence posts, call 811 at least two business days before you plan to start your project.

Learn more about safe digging by going to the webpages linked below.

Residential customers

Put safety first. Find out the steps you need to take to prevent accidents when digging on your property.

VISIT GAS SAFETY FOR RESIDENTIAL CUSTOMERS

Farmers and ranchers

Prevent damage caused by gas leaks. You'll find information specific to agriculture and ranching.

VISIT GAS SAFETY FOR FARMERS AND RANCHERS

School communities

Be aware of digging hazards and precautions that should be taken before starting both large and small projects on your campus.

VISIT GAS SAFETY FOR SCHOOL COMMUNITIES

For additional information about 811 or to make an online request, go to the Underground Service Alert North or DigAlert websites.

VISIT USANORTH811.ORG

VISIT DIGALERT.ORG

Gas safety

Learn how to safely turn off your gas, what to do if you suspect a gas leak and more.

LEARN MORE ABOUT GAS SAFETY

Carbon monoxide poisoning

Carbon monoxide is a dangerous gas. Play it safe with early detection.

LEARN MORE ABOUT CARBON MONOXIDE POISONING

Sewer cleaning safety

Cleaning out a sewer pipe can cause a gas leak if a gas line intersects the sewer pipe.

LEARN MORE ABOUT SEWER CLEANING SAFETY

Play our video to learn more

Call 811 Before You Dig

AFTER THE VIDEO, TAKE THE QUIZ

Audio description and transcript also available for this video.

Access an audio descriptive version
Download a transcript (PDF, 22 KB)

PLAY VIDEO

Pacific Gas and Electric Company®

Utility Procedure: TD-5801P-01
Publication Date: 08/31/2016; Effective Date: 09/14/2016 Rev: 0

Pipeline Public Awareness Program Process

SUMMARY

This utility procedure describes actions performed by Pacific Gas and Electric Company (PG&E or Company) for the public awareness program (PAP). The PAP includes development and implementation of public education programs addressing key stakeholder audiences including the affected public, emergency officials, public officials, and excavators.

Level of Use: Informational Use

TARGET AUDIENCE

Personnel responsible for gas transmission and distribution (T&D) operations, emergency preparedness and public awareness, land management, gas transmission engineering, external relations, government relations, and gas maintenance and construction (M&C)

SAFETY

NA

BEFORE YOU START

NA

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Pipeline Public Awareness Program Process

PROCEDURE STEPS

1 Program Overview

1.1 Refer to Utility Standard, TD-5801S, "Pipeline Public Awareness Program," Attachment 1, "Public Awareness Program Management Commitment," to review PG&E leadership support for the Public Awareness Program (PAP).

1.2 PG&E performs on-going communications with the affected public, excavators, emergency response officials, and public officials to maintain public safety by raising the awareness of pipelines and reducing the likelihood and potential impact of pipeline damage through education, resources, and programs like 811 "Call Before You Dig".

NOTE

The PAP is designed to enhance public safety, emergency preparedness, and environmental protection through increased public awareness and knowledge. The program objectives outlined below align with PG&E corporate goals and operational focus on gas pipeline safety, damage prevention, and emergency response preparedness.

1.3 Public awareness personnel perform outreach activities for the following individuals living and working within the PG&E distribution service territory and near transmission pipelines, non-odorized pipelines, storage facilities, and compressor stations:

- General affected public (AP)
- Emergency response officials (ER)
- Professional excavators (EX)
- Local public officials (PO)

Refer to information provided in the gas emergency response plan (GERP) for a current roster of public safety specialists.

- GERP web page
- GERP, Volume 2 (with roster)

1.4 Public awareness personnel utilize consistent objectives, tools, and measurement components to enhance public safety while maintaining the flexibility necessary to monitor and respond to the needs of various audiences or circumstances per the PAP.

Pipeline Public Awareness Program Process

2 Program Objectives

2.1 Public awareness personnel review the PAP per Utility Standard TD-5801S, "Pipeline Public Awareness Program,"

NOTE
The PAP aligns with the corporate objective to be the safest, most reliable gas company in the United States.

2.2 Public awareness personnel perform PAP program activities targeting excavators, public officials, emergency officials, and the affected public to align with the Company operation focus in the areas of gas pipeline safety, damage prevention, and emergency response preparedness. Program activities mitigate identified risks through Integrity Management (IM) and support other community relations and relationship-building activities with key stakeholders.

2.3 PAP objectives include:

1. **Awareness:** The PAP increases awareness of the following:

   - The presence of PG&E natural gas pipelines
   - The role pipelines play in transporting and delivering energy
   - The programs and activities PG&E has in place to keep pipelines safe

   Increased awareness leads to greater stakeholder engagement in pipeline safety AND helps reduce the likelihood of emergencies or gas releases.

2. **Damage Prevention:** The PAP contributes to a reduction in third-party damage to pipelines through educational outreach regarding safe excavation near pipelines and required actions prior to excavating near underground pipelines. The program also contributes to a reduction in right-of-way (ROW) encroachment through increased awareness regarding ROW and ROW restrictions.

3. **Emergency Response Readiness:** The PAP contributes to emergency response readiness by providing information regarding how to recognize and appropriately respond to a gas leak to protect life, property, and the environment. Additionally, the PAP enhances Emergency Official response readiness through the following activities:

   - Educational outreach
   - Information exchange
   - Training simulations focused on safe handling of utility emergencies.

   Improved response readiness leads to timely notification regarding a potential gas leak and a coordinated response between Company personnel and Emergency Officials.

Pipeline Public Awareness Program Process

3 Overview of Gas Facility Assets

3.1 Refer to Appendix A, "Gas Facility Assets Included in the PAP," for overview information.

4 Stakeholder Audiences

4.1 PG&E responsible departments, as listed in Appendix A of TD-5801S, provide information to the following stakeholder audiences:

- Affected public
- Emergency officials
- Public officials
- Excavators

4.2 Public awareness personnel identify individual stakeholders AND create contact lists for communication outreach. Data sources include the following:

- PG&E customer information system (CIS)
- Information managed and analyzed within PG&E geographic information system (GIS)
- Pipeline association for public awareness (PAPA) contact lists
- Commercially available data and lists
- One call center databases
- Other data and lists provided by the State of California or maintained internally by Company departments.

4.3 The PAP manager reviews available data sources and methodologies for creating stakeholder contact lists annually in conjunction with internal resources and third-party vendors to determine any changes to the current list methodology for the upcoming program year.

4.4 Appendix B, "Stakeholder Definitions, Identification and Outreach Table," provides a detailed overview of the process used to create contact lists for each stakeholder group. Changes made to the stakeholder identification process are included in Appendix B.

Pipeline Public Awareness Program Process

5 Message Content and Delivery Methods

NOTE

Messages and delivery methods are tailored for each targeted stakeholder audience providing the following:

- An overview of the location of pipelines and aboveground infrastructure
- How to recognize and appropriately respond to a pipeline leak
- Pipeline purpose and reliability
- Emergency preparedness activities
- Hazards associated with a pipeline leak
- IM activities
- Other damage prevention measures

5.1 Communication with affected stakeholder audiences as identified in Appendix B.

1. Communicate the PAP messages to the affected public in English.

   a. Provide messages for the affected public in languages spoken at home by at least 5% of residents living in the 40 PG&E gas asset counties. Use United States Census data collected through the American Community Study (ACS) to identify these languages.

      (1) The PAP administrator monitors changes in languages spoken at home in PG&E gas asset counties using the ACS 5-year data set for PG&E counties and recommends any changes through the annual review or program effectiveness report.

      (2) Refer to Attachment 2, "Process to determine languages other than English for Public Awareness Outreach to the Affected Public," for the most recent summary of languages spoken at home in the PG&E gas asset counties.

   b. Promote the notification regarding the availability of information in these languages using in-language text on baseline materials distributed to the affected public.

   c. Print the notification regarding the availability of information in Chinese, Spanish, and Vietnamese using in-language text in baseline materials. PG&E call centers contract with a translation services company to provide in-language phone support in more than 190 languages.

Pipeline Public Awareness Program Process

5.1 (continued)

2. Provide materials in English to emergency official personnel.

3. Provide materials in English to public official personnel.

4. Provide materials in English AND Spanish, to excavator (due to the large percentage of Spanish-speaking construction and excavation workers across the United States and construction crews often travel across the country for jobs.)

5.2 Baseline and Supplemental Message Content

1. Refer to the baseline and supplemental messages outlined in Appendix B, and Appendix C, "Supplemental Outreach Activities and Triggers," to meet the overall program objectives identified in Section 2, including raising the awareness of pipelines and reducing the likelihood and potential impact of pipeline damage through education, resources, and programs.

2. Evaluate communication materials during the annual review to determine any changes that must be made for the following program year.

5.3 Baseline and Supplemental Program Delivery Methods

NOTE

For the affected public customers, PG&E primarily utilizes company-managed customer communication methods, such as bill inserts and customer e-bills. For non-customers and other stakeholder groups, PG&E contracts with PAPA and other third-party vendors to distribute communication materials to stakeholders through United States Postal Service (USPS) and email campaigns.

1. Refer to Appendix B, and Appendix C, to identify baseline and supplemental program delivery methods as appropriate.

   a. Evaluate the methods used to communicate with each stakeholder group during the annual review to determine if the most effective methods are being used.

   b. Collect and review documentation related to delivery methods and communication activities as part of the annual program review process.

Pipeline Public Awareness Program Process

5.4 Supplemental Programs - Delivery Methods and Vehicles

NOTE

Supplemental PAP elements are designed to expand and enhance the messages and frequency of baseline program elements. Supplemental programs may target a specific subset of a stakeholder audience or a specific geographic area. In addition, supplemental programs often leverage high-touch activities that are not practical as a method to completely reach all stakeholders within the baseline frequency requirements (e.g., face-to-face meetings or group training sessions).

1. The PAP Committee, as listed in Attachment 1, "Pipeline Public Awareness Committee – Current Representatives," reviews, at least twice a year, the supplemental program activities planned for the year and discusses the need for additional activities. The PAP Committee considers the following when developing supplemental programs:
   - Potential hazards
   - High consequence areas (HCA)
   - Population density
   - Land development activity
   - Land farming activity
   - Third-party damage incidents
   - Environmental considerations
   - Pipeline history in an area
   - Specific local situations
   - Regulatory requirements or requests
   - PAP effectiveness evaluation results
   - Construction, maintenance and/or IM activities
2. The PAP Committee documents the discussions regarding supplemental program activities in PAP Committee meeting minutes.
3. The PAP Committee refers to Appendix C, for details regarding current supplemental programs, frequency and delivery methods.

Pipeline Public Awareness Program Process

6 Program Documentation

6.1 Retain documents per the Record Retention Schedule.

6.2 Records include, but are not limited to, the following:

- The written PAP and related procedural documents (includes historical versions of the PAP).
- PAP Committee meeting notes.
- Mailing lists, communication materials, sign-in sheets, USPS mailing list certification, and other documentation demonstrating compliance with the baseline and supplemental program activities outlined in the PAP.
- Program feedback including survey data, survey reports, business reply cards, and post-meeting feedback used to evaluate the effectiveness of program activities.
- Annual program review reports.
- Program effectiveness reports.

7 Program Evaluation and Effectiveness

7.1 PG&E responsible departments as listed in Appendix A of TD-5801S complete the following:

1. Review and evaluate the effectiveness of the PAP to assess whether the objectives of the program are being achieved.
2. Perform a program implementation review AND a program effectiveness evaluation per TD-5801S.
3. Perform PAP implementation reviews and effectiveness evaluations, including:
   - Determine whether the current program is effective in achieving its objectives.
   - Provide information on implementing improvements to the program.
   - Demonstrate whether the program is being implemented as planned.

Pipeline Public Awareness Program Process

8 Annual Program Review

8.1 PG&E responsible departments conduct an annual review of the program and the documentation of program implementation during the previous year, including the following tasks:

- Ensure the PAP was executed according to the requirements defined in this plan.
- Collect and review program documentation.
- Confirm communication methods are effectively reaching stakeholder audiences.
- Analyze data collected throughout the year to conduct supplemental communications, implementing program changes, or both.
- Review changes in regulation to ensure they are included in program updates.

8.2 The PAP administrator or designated resource conducts the annual review and develops a written report summarizing the following:

1. **Program implementation details**: A summary of all baseline program activities and significant supplemental activities conducted during the year include the following:
   - Dates
   - Delivery methods
   - Frequency
   - Messages contained in each delivery method
   - A list of vendors supporting or executing the activities
2. **Outreach summary**: Details regarding the number of individuals reached by each baseline program activity and an estimate of the percentage of stakeholders reached. The outreach summary includes significant supplemental activities such as traffic to the company website, attendance at stakeholder meetings and targeted direct mail campaigns. Significant fluctuations (10 percent or greater) in baseline outreach compared to previous years is noted and additional context provided.
   - The outreach summary also references the estimated percentage of stakeholders reached through baseline and significant supplemental activities based on return mail from targeted direct mail campaigns. Refer to Attachment 4, "Return Mail Analysis," for more details regarding the return mail analysis process.

Pipeline Public Awareness Program Process

8.2 (continued)

3. **Assessment of message comprehension and understanding**: A summary of stakeholder feedback collected during the year and details regarding any notable fluctuations compared to previous years.

   a. The following are examples of data referenced in this section:

   - Survey data collected at meetings from emergency responders and excavators
   - Stakeholder feedback collected through business reply cards or satisfaction surveys
   - Stakeholder feedback collected through phone surveys, mail surveys, online surveys, focus groups or stakeholder interviews
   - Pre-Testing: Reports from focus groups, stakeholder interviews or online panels conducted to gauge message clarity and understandability of program materials

4. **Bottom-Line results**: Details regarding the number of third-party incidents, near misses, and/or any additional data tracked by Damage Prevention helpful in understanding excavator needs, issues and trends. In addition, this section of the report includes any data collected regarding stakeholder perception of safety.

5. **Program changes**: List any changes made to the program during the previous year including but not limited to the following:

   - Modifications to the written plan
   - Changes to company assets included in the Company PAP
   - New or updated communication materials
   - Increased communication frequency
   - Changes to the process used to create or manage stakeholder contact lists
   - This section also outlines any planned program changes for the upcoming year based on recommendations provided by the PAP administrator, PAP committee members, personnel or vendors supporting the program.

8.3 The PAP Committee performs a review of the annual review report.

8.4 THE PAP Committee shares the results of the annual review with personnel identified in TD-5801S, AND submits it to the vice president (VP), gas T&D operations for approval.

Pipeline Public Awareness Program Process

9 Program Effectiveness Evaluation

9.1 Perform an extensive program evaluation per TD-5801S, to ensure the PAP is effectively accomplishing the program objectives.

- The effectiveness evaluation includes the following:
  - Analysis of annual program reviews
  - Full review of the PAP written plan
  - Review and discussion of applicable operational data (particularly related to third-party excavation damage and encroachment activities)
  - Analysis of survey data designed to measure stakeholder awareness, understanding, behaviors, and behavioral intent

9.2 Conduct effectiveness evaluation either internally OR use a third-party resource to assist with all or part of the effectiveness evaluation.

9.3 Document the effectiveness evaluation in a detailed written report.

9.4 The PAP Committee reviews the report.

9.5 Provide a copy of the report to individuals listed in Appendix B AND submit it to the VP, gas T&D operations for approval.

1. The effectiveness evaluation is designed to accomplish the following:
   - Gauge whether the information is reaching the intended stakeholder audience.
   - Understand whether the messages are being delivered effectively and frequently enough to achieve desired behavioral intent or behavior change.
   - Measure whether the stakeholder audience is responding appropriately to pipeline safety messages through changes in stakeholder recall, message comprehension, engagement, and behavior change.
   - Evaluate whether the PAP is improving safety near pipelines by raising the awareness of the presence of pipelines in communities and informing stakeholders about the significant role they play in helping to prevent and respond to pipeline emergencies.
   - Identify areas for continuous program improvement.
   - Review changes in regulation to ensure they are included in program updates.

Pipeline Public Awareness Program Process

9.6 At a minimum, include an assessment of the following information in the Program Effectiveness Evaluation report:

1. **Program Outreach**: An assessment of the effectiveness of the delivery methods used to deliver messages to stakeholders. This assessment includes calculations of the percentage of each stakeholder audience reached through specific communication methods or combinations of methods used within a common communication campaign and compares stakeholder reach trends over the 4-year period. The effectiveness evaluation also documents fluctuations in program outreach numbers and the percentage of stakeholders reached based on return mail analysis over the 4-year period.

2. **Recall and Understandability of Message Content**: The effectiveness evaluation uses survey data and other available operational data to assess message recall and understanding for key messages outlined in this plan. Survey data collected over the past 4 years related to recall and message comprehension is compared to data analyzed during the previous 4-year effectiveness evaluation to assess data trends.

3. Refer to Appendix D, "Acceptable Methods for Assessment of Recall and Understandability."

   a. Use one or more of the methods for each audience during the 4-year evaluation timeframe.

   b. The methods used may be conducted by PG&E or by a third-party vendor.

      - Any outside vendors used to collect assessment data is detailed in the effectiveness evaluation report.

4. **Behaviors and Behavioral Intent**: The effectiveness evaluation utilizes survey data and other available operational data to assess the extent that stakeholder behaviors and their behavioral intent (as expressed through survey feedback) aligns with desired behaviors and message content.

   - Refer to Appendix E, "Desired Behavior by Stakeholder," to determine the types of behaviors to be assessed and provide examples of operational data or survey questions to be used to assess behaviors and behavioral intent.

   - Analyze behavioral metrics and compare them to data included in the previous 4-year evaluation report.

5. **Bottom-Line Results**: The effectiveness evaluation utilizes operational data to analyze trends over the previous 4-year period related to incidents, near misses, excavation damages resulting in pipeline failure, excavation damages not resulting in pipeline failure (i.e. damages not resulting in a leak), segmented data related to at-fault party and excavation activities, One-Call ticket data, and other relevant data as determined by the PAP Administrator necessary to assess the impact of public awareness programs in reducing the risk of third-party excavation damage to the PG&E system. In addition, the effectiveness evaluation utilizes survey data to assess the current customer and non-customer affected public perception of safety.

Pipeline Public Awareness Program Process

9.6 (continued)

6. Based on assessment of these four areas, the PAP Administrator proposes changes to the program to improve program effectiveness. These may lead to changes to the written plan, communication materials, delivery frequency, and contact list creation process or data sources.

9.7 Scheduling Surveys

1. Surveys are scheduled as follows:

- AP every 2 years (even years)
- EX every 2 years (odd years)
- ER every 2 years (odd years)
- PO every 2 years (odd years)

10 Program Review and Effectiveness Tracking Documents

10.1 The PAP Administrator, or designated resource, tracks information related to key program metrics in the following program measurement documents:

- **Recall and Message Comprehension Charts:** Survey questions are organized by audience and message, and entered into the spreadsheet for comparison with past results.
- **Outreach Charts:** Data is entered regarding the number of individuals or entities reached with a specific method.
- **Behavior Chart:** Survey questions related to the percentage of intended stakeholders understanding and retaining key information is tracked in the spreadsheet. Data is compared to past results.
- **Bottom-Line Result Chart:** Tracks a number of operational data and survey questions related to perception of the safety of PG&E pipelines.

10.2 Use the data tracked in these documents, along with survey reports and operational data reports, for reference during the annual review and 4-year effectiveness evaluation.

10.3 Archive documents per the Record Retention Plan.

END of Instructions

Pipeline Public Awareness Program Process

DEFINITIONS

NA

IMPLEMENTATION RESPONSIBILITIES

The vice president gas T&D operations is responsible for approving major changes to the program.

The transmission integrity management senior director is responsible for overseeing and approving the PAP budgetary and resource requirements.

The gas T&D operations compliance director is responsible for approving revisions to the PAP.

The PAP manager is responsible to oversee and manage the PAP to ensure compliance with company and regulatory policies and procedures.

GOVERNING DOCUMENT

Utility Standard TD-5801S, "Pipeline Public Awareness Program"

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Code of Federal Regulations (CFR) Title 49-Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Section (§) 615, "Emergency plans."

49 CFR Part §192.616, "Public awareness."

API RP 1162, 1st Edition, December 2003

REFERENCE DOCUMENTS

Developmental References:

Risk Management Procedure (RMP) 12, "Pipeline Public Awareness Program," Revision 11

Supplemental References:

NA

Pipeline Public Awareness Program Process

APPENDICES

Appendix A, "Gas Facility Assets Included in the PAP"

Appendix B, "Stakeholder Definitions, Identification, and Outreach"

Appendix C, "Supplemental Outreach Activities and Triggers"

Appendix D, "Acceptable Methods for Assessment of Recall and Understandability"

Appendix E, "Desired Behavior by Stakeholder"

ATTACHMENTS

Attachment 1, "Pipeline Public Awareness Committee – Current Representatives"

Attachment 2, "Process to determine languages other than English for Public Awareness Outreach to the Affected Public"

Attachment 3, "Process for Calculating Public Awareness Bottom-Line Results Metrics"

Attachment 4, "Return Mail Analysis"

DOCUMENT RECISION

This document supersedes RMP-12, "Pipeline Public Awareness Program," Revision 11, issued 06/2015.

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REVISION NOTES

Where?	What Changed?
NA	This is a new document.

Pipeline Public Awareness Program Process

Appendix A, Gas Facility Assets Included in the PAP

Table A-1. Gas Facility Assets Included in the PAP

Asset Type	Asset Details and Descriptions

PG&E Pipeline Assets included in the PAP	All regulated gas pipelines in California owned by the Company and Standard Pacific Pipeline Incorporated (Standard Pacific) covered by Code of Federal Regulations (CFR), Title 49-Transporations, Part 192—Transportation of Natural and Other Gas By Pipeline: Minimum Federal Safety Standards.
	• 5,733 miles of natural gas transmission pipelines
	• 42,703.2 miles of distribution natural gas mains
	• 3,383,060 natural gas services
	• 12 compressor stations:
	  • Bethany
	  • Delevan
	  • Gerber
	  • Burney
	  • Tionesta
	  • Kettleman
	  • Hinkley
	  • Topock
	  • Santa Rosa
	  • Pleasant Creek
	  • Los Medanos
	  • McDonald Island
	• 8 storage facilities:
	  • Los Medanos
	  • McDonald Island
	  • Pleasant Creek
	  • Santa Cruz
	  • North Sac
	  • Yuba City
	  • Whisky Slough
	  • Turner Cut
	• 33 fixed-location CNG filling stations

Standard Pacific assets included within the PAP	54.7 miles of natural gas transmission pipelines
Non-Odorized Pipeline Segments	Included in the pipeline assets listed above are 246.5 miles of non-odorized natural gas pipeline from various gas well production receipt point meters where dry-processed gas is delivered to PG&E (Code of Federal Regulations (CFR) Title 49—Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Section 3, "Definitions"). In addition, the transmission pipeline segments between the individual gas well receipt points and the downstream pipelines may not be odorized. Odorant is added at regulator stations on lines serving customers upstream of odorizer stations.
Compressed Natural Gas (CNG) Filling Stations	PG&E operates 33 fixed-location CNG filling stations. Communication with customers regarding these facilities is included in Appendix C, "Supplemental Outreach Activities and Triggers." Refer to "Supplemental Program Delivery Methods and Vehicles" information within Appendix C.
Portable Liquefied Natural Gas (LNG) and Portable CNG Facilities	PG&E operates portable LNG facilities and portable CNG facilities on a project-specific basis as needed. Portable LNG facilities and portable CNG facilities are not included in the PAP. Communication with stakeholders regarding these facilities occurs on a project basis and is managed by LNG/CNG operations.
Gill Ranch Storage Field	PG&E owns 25% interest in the Gill Ranch Storage Field, operated by Gill Ranch Storage Ltd. The Gill Ranch Storage Field is **not** included in the PAP. PAP requirements are executed by Gill Ranch Storage Ltd.
Gas Storage Facilities	Stations storing, pressurizing, and processing gas using an underground reservoir formation or storage tank. See Utility Standard TD-4551S, "Station Critical Documentation."
Underground Holders	Holders mean any structure used to store gas, which either has a displacement of 500 or more cubic feet (ft), or will contain 10,000 or more standard cubic ft of gas at its maximum design pressure, except that a pipeline which is used primarily for transmission or distribution of gas, but which also serves a storage function, is not a holder for purposes of general order (GO) 112-E.
Compressor Station	Stations pressurizing natural gas for the purpose of transporting it from one location to another. See Utility Standard TD-4551S, "Station Critical Documentation."

Appendix B, Stakeholder Definitions, Identification, and Outreach
Page 1 of 4

Table B-1. Stakeholder Definitions, Identification, and Outreach

Stakeholder Audience	Audience Subset	Audience Definition	Audience Examples	Audience Identification Process	Baseline Messages	Baseline Delivery Methods	Baseline Required Frequency	Baseline Actual Frequency
Affected Public	LDC Gas Customers	Residents and businesses residing within PG&E service territory and receive gas bills from PG&E either by mail or electronically	• PG&E residential gas customers • PG&E commercial or large industrial customers, critical facility customers (hospitals, nursing homes, colleges, universities, technical colleges), agriculture customers • Master-metered customers billing "sub-metered tenants" for gas service • Core transport agents billing core gas aggregation customers for gas service	Contact information for all active gas customers is maintained in PG&E CIS. Customer accounts are maintained at the account level and include a billing address, premise address, email (if available) and meter identification number.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • Leak recognition and response • How to get additional information	• Mailed bill inserts are sent to gas customers • A link to view the bill insert is included in the e-mail sent to electronically billed customers and can be accessed from PG&E website. • Customers providing an email address also receive a separate e-mail campaign with safety information	Twice Annually	Twice Annually
Affected Public	Electric Customers	Residents and businesses residing within the PG&E service territory who are not gas customers but who receive electric bills from PG&E either by mail or electronically	• PG&E electric customers	Contact information for all active electric customers is maintained in PG&E CIS. Customer accounts are maintained at the account level and include a billing address, premise address, email (if available) and meter identification number.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • Leak recognition and response • How to get additional information	• Mailed Bill Inserts are sent to electric customers • A link to view the bill insert is included in the e-mail sent to electronically billed customers and can be accessed from PG&E website. • Customers who have provided an email address also receive a separate e-mail campaign with safety information	Twice Annually	Twice Annually
Affected Public	Other: (Residents/ Businesses who reside within PG&E gas service territory but do not pay PG&E for gas or electric service)	Residents and businesses who reside within the gas service territory who do not receive a gas or electric bill from PG&E	• Residential or commercial tenants on master meter gas or electric accounts who pay their landlord directly for gas or electricity delivered by PG&E • Residents or businesses who are community choice aggregation (CCA) customers and purchase electricity through core transport agencies (CTAs) • Core gas aggregation customers • Direct access electricity customers	Varies based on audience: • Residential and commercial tenants on master-metered systems: Service address for master-meter system is maintained in PG&E CIS as part of the master meter system operator information. • Residents and commercial tenants who pay core transport agents for electricity through community choice aggregation contracts: core transport agents maintain contact information for residential/commercial customers they bill for gas or electric service. An active list of CTAs is available online at http://www.pge.com/en/b2b/retailenergysuppliers	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • Leak recognition and response • How to get additional information	• A targeted direct-mail program is sent to residents and businesses • Press releases • Mass media campaigns and sponsorships • Website content • Community events and partnerships	Annually	Annually
Affected Public	School Administrators and District Officials in Distribution Service territory	School administrators and district officials for educational institutions located in PG&E distribution asset counties meeting the following criteria as outlined in the California Department of Education school definition: 1. Grades kindergarten through grade 12 2. One or more teachers to give instruction 3. An assigned administrator 4. Based in one or more buildings; and 5. Enrolled or prospectively enrolled students 6. 6 or more students enrolled (private schools)	• Public schools (K-12) • Private schools (K-12) • Charter schools (K-12)	1. School Administrators and District Officials are identified using a school contact database for public and private schools provided by the California Department of Education publically available on their website at http://www.cde.ca.gov/re/sd/. New data lists are provided annually and distribution asset counties are extracted from the public and private school database for additional analysis. 2. Contact information associated with each school is extracted and used to create a contact list. 3. Contact information associated with the district contact for each school is extracted and used to create a contact list.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • Leak recognition and response • How to get additional information	• A targeted e-campaign is sent to school administrator contacts for distribution to faculty and staff • A targeted e-campaign is sent to school district officials to notify them of communication with school administrators in their district. • A targeted direct mail brochure is sent to schools not having an email address.	Twice Annually	Twice Annually

Appendix B, Stakeholder Definitions, Identification, and Outreach
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Table B-1. Stakeholder Definitions, Identification, and Outreach (continued)

Stakeholder Audience	Audience Subset	Audience Definition	Audience Examples	Audience Identification Process	Baseline Messages	Baseline Delivery Methods	Baseline Required Frequency	Baseline Actual Frequency
Affected Public	School Administrators and District Officials within 1000 ft of a Transmission Pipeline, Gathering Pipeline, Gas Storage Facility or Compressor Station	School administrators and district officials for educational institutions located within 1000 ft of a PG&E transmission pipeline, gathering pipeline, compressor station or gas storage facility meeting the following criteria as outlined in the California Department of Education school definition: 1. Grades kindergarten through grade 12 2. One or more teachers to give instruction 3. An assigned administrator 4. Based in one or more buildings; and 5. Enrolled or prospectively enrolled students 6. 6 or more students enrolled (private schools)	• Public schools (K-12) • Private schools (K-12) • Charter schools (K-12)	1. School Administrators and District Officials are identified using a school contact database for public and private schools provided by the California Department of Education publically available on their website at http://www.cde.ca.gov/re/sd/. New data lists are provided annually. Schools and districts located within PG&E transmission asset counties are extracted from the public and private school database for additional analysis. 2. The GIS department or a designated third party vendor analyzes the location of all schools within PG&E transmission asset counties and calculates the distance between the centerline and the school property line using parcel data and satellite imagery. 3. Contact information associated with schools located within 1,000 feet (ft) from the centerline of a transmission pipeline, gathering pipeline, gas storage facility or compressor station is extracted and used to create a contact list. 4. Contact information associated with the districts for each of these school is extracted and used to create a contact list.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call Requirements • Leak recognition and response • Pipeline location information • How to get additional information • Availability of list of pipeline operators through NPMS	• A targeted e-campaign is sent to school administrator contacts for distribution to faculty and staff. • A targeted e-campaign is sent to school district contacts to notify them of communication with school administrators in their district. • A targeted direct mail brochure is sent to schools not having an email address.	Every Two Years	Every Two Years
Affected Public	Residents, Businesses, or places of congregation located within 1000 ft of Transmission Pipeline	Residents, Businesses or Places of Congregation located within 1000 ft of a transmission pipeline who are customers.	• Landowners/residents • Tenants • Farmers • Businesses • Places of worship • Hospitals or other medical facilities • Prisons • Day-care facilities • Senior centers • Universities/colleges	Affected Public gas and electric customer contacts within 1000 ft of a Transmission Pipeline. Contact information for all active gas and electric customers is maintained in PG&E CIS. Customer accounts are maintained at the account level and include a billing address, premise address, email (if available) and meter identification number.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call Requirements • Leak recognition and response • Pipeline location information • How to get additional information • Availability of list of pipeline operators through NPMS	• A bill insert is sent to PG&E electric and gas customers	Every Two Years	Twice Annually

Appendix B, Stakeholder Definitions, Identification, and Outreach
Page 3 of 4

Table B-1. Stakeholder Definitions, Identification, and Outreach (continued)

Stakeholder Audience	Audience Subset	Audience Definition	Audience Examples	Audience Identification Process	Baseline Messages	Baseline Delivery Methods	Baseline Required Frequency	Baseline Actual Frequency
Affected Public	Residents, Businesses, or places of congregation located within 1000 ft of Transmission Pipeline	Residents, Businesses or Places of Congregation located within 1000 ft of a transmission pipeline who are not customers	• Landowners/residents • Tenants • Farmers • Businesses • Places of worship • Hospitals or other medical facilities • Prisons • Day-care facilities • Senior centers • Universities/Colleges	Affected Public non-customer contacts within 1000 ft of Transmission Pipeline will be identified or updated annually prior to each baseline campaign outreach. 1. GIS department creates Shape files containing the geographic boundaries using centerline data with a minimum distance of 1000 ft from a transmission pipeline. 2. PG&E contracts with a third party vendor to create a mailing list using the Shape files provided by the GIS department. The vendor utilizes parcel data and other available data sources and formats the mail list per USPS standards. 3. Mailing addresses are verified by a third party vendor using available USPS databases before mailing to ensure accuracy and deliverability. Validation includes the identification of any currently USPS-identified vacant properties. The vendor recommends if any addresses should be removed from the mailing list based on vacancy information. 4. The PAP administrator or designated third-party vendor is responsible for reviewing any undeliverable mail and provides this information to the list vendor for review. The PAP administrator determines if additional communication activities are needed per Attachment 4, "Return Mail Analysis." 5. Addresses identified as vacant are annually re-assessed using the USPS database and if occupied a mailing is sent to that address.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call Requirements • Leak recognition and response • Pipeline location information • How to get additional information • Availability of list of pipeline operators through NPMS	• A targeted direct-mail program is sent to residents who do not receive the semi-annual bill insert	Every Two Years	Annually
Emergency Official	Emergency Officials in Asset County	• Local, state, or regional officials, agencies and organizations with emergency response and/or public safety jurisdiction located within the gas distribution service territory. • Local, state, or regional officials, agencies and organizations with emergency response and/or public safety jurisdiction located in counties having gas transmission pipeline, gas storage facility, or compressor station.	• Fire departments • Police/sheriff departments • Local emergency planning commissions (LEPCs) • Emergency management agencies (EMAs) • 911 centers or public safety access points (PSAP)	1. GIS department identifies gas asset counties and provides to PAP manager. PAP manager provides to third-party. 2. A third party vendor (PAPA) identifies the Emergency Officials within each county using a classification under the applicable U.S. Government, Standard Industry codes (SIC). The applicable SIC codes are listed in program documentation provided by PAPA. 3. Emergency officials are also identified using commercially available data sources obtained from the National Public Safety Information Bureau. National Public Safety Information Bureau updates their data annually through phone calls to verify accuracy of contact information.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information • Potential hazards[1] • Pipeline location information and availability of NPMS[1] • Gathering pipeline location and purpose[2] • Specific description of products transported and any potential special hazards[2]	• A targeted mailing of a printed packet of materials (includes letter, "Emergency Responder Guidebook", a multi-page newsletter about pipeline awareness, link to online capability survey and other training and reference materials) distributed by PAPA on behalf of the company.	Annually	Annually

Notes:
1. Refers to Transmission Assets Only
2. Refers to Gathering Assets Only

Appendix B, Stakeholder Definitions, Identification, and Outreach
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Table B-1. Stakeholder Definitions, Identification, and Outreach (continued)

Stakeholder Audience	Audience Subset	Audience Definition	Audience Examples	Audience Identification Process	Baseline Messages	Baseline Delivery Methods	Baseline Required Frequency	Baseline Actual Frequency
Public Official	Public Officials in Asset County	• Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located within the gas service territory. • Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located in counties having a gas transmission pipeline, gas storage facility or compressor station.	• Planning boards • Zoning boards • Permit/Licensing departments • Building Code Enforcement departments • City and County managers • Public and Government officials • Local Governing Councils • Public Utility boards • Public street, road and highway departments (CalTrans)	1. GIS department identifies gas asset counties and provides to PAP manager. PAP manager provides to third-party. 2. A third party vendor (PAPA) identifies the Emergency Officials within each county using a classification under the applicable U.S. Government, Standard Industry (SIC) codes. The applicable SIC codes are listed in program documentation provided by PAPA. 3. Emergency officials are also identified using commercially available data sources obtained from the National Public Safety Information Bureau. National Public Safety Information Bureau updates their data annually through phone calls to verify accuracy of contact information.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information • One-call Requirements[1] • Pipeline location information and availability of NPMS[1] • Gathering pipeline location and purpose[3] • Copies of materials provided to affected public and emergency officials[2]	• A targeted mailing of a multi-page newsletter distributed by PAPA on behalf of the company.	Every Three Years	Annually
Excavators	Excavators in California	Companies performing or directing excavation work in the State of California and having a California business address.	• Contractors • Construction companies • Excavation equipment rental companies • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Public work officials	Excavator contacts will be identified or updated annually prior to each baseline campaign outreach. 1. A third party vendor (PAPA) identifies Excavator contacts with mailing addresses in California using SIC codes. The applicable SIC codes are listed in program documentation provided by PAPA. Lists are updated annually. 2. PAPA utilizes a combination of commercial data sources (Info USA and Acxiom) and public data (licensing boards, trade associations) to identify excavator, contractor, agriculture and land developer contacts.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • Leak recognition and response • One-call requirements • How to get additional information • Gathering pipeline location and purpose[2]	• A targeted mailing of the "Excavation Safety Guide" booklet distributed by PAPA on behalf of the company.	Annually	Annually
Excavators	Land Developers in California	Land Developers: Companies and private entities involved in land development and planning in the state of California and who have a California business address	• Land developers • Home builder	Excavator contacts will be identified or updated annually prior to each baseline campaign outreach. 1. A third party vendor (PAPA) identifies Excavator contacts with mailing addresses in California using SIC codes. The applicable SIC codes are listed in program documentation provided by PAPA. Lists are updated annually. 2. PAPA utilizes a combination of commercial data sources (Info USA and Acxiom) and public data (licensing boards, trade associations) to identify excavator, contractor, agriculture and land developer contacts.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-Call requirements • Leak recognition and response • ROW encroachment prevention • Availability of list of pipeline operators through NPMS • Gathering pipeline location and purpose[2]	• A targeted mailing of the "Excavation Safety Guide" booklet distributed by PAPA on behalf of the company.	Annually	Annually
Excavators	One Call Centers in California	One-Call Center: Excavation One-Call centers in the state of California.	• USA North • USA South	PG&E is a member of the One-Call Centers in California	• Pipeline location information • Other requirements of the applicable One-Call Center	• Copies of the "Excavation Safety Guide" booklet are distributed by PAPA on behalf of the company to One Call Centers • PG&E provides information as requested including maps and notification requirements.	Annually	Annually

Notes:
1. Refers to Transmission Assets Only
2. Refers to Gathering Assets Only

Appendix C, Supplemental Outreach Activities and Triggers

Table C-1. General Affected Public (AP)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification	Supplemental Activity	Message(s)	Frequency
Regulatory requirement	RP-1162 Supplemental Messages	Residents, businesses, or places of congregation located within 1000 ft of transmission pipelines	Residents, businesses or places of congregation located within 1000 ft of a transmission pipeline	• Landowners/ residents • Tenants • Farmers • Businesses • Schools • Places of worship • Hospitals or other medical facilities • Prisons • Day-care facilities • Senior centers	1. GIS department creates Shape files containing the centerline and geographic boundaries using centerline data equal to a distance of 1000 ft from a transmission pipeline. 2. PG&E contracts with a third-party vendor to create a mailing list using the Shape files provided by the GIS department. The vendor utilizes parcel data and other available data sources and formats the mail list per USPS standards. 3. Mailing addresses are verified by a third-party vendor using available USPS databases before mailing to ensure accuracy and deliverability. Validation includes the identification of any currently USPS-identified vacant properties that should be removed from the list before mailing. 4. The PAP administrator or designated third-party vendor is responsible for reviewing any undeliverable mail and provides this information to the list vendor for review. The PAP administrator determines if additional research is needed per Attachment 4, "Return Mail Analysis." 5. Addresses identified as vacant are annually re-assessed using the USPS database and, if occupied, a mailing is sent to that address.	Printed brochure contains information about ROW encroachment prevention and PG&E IM Program and activities. Refer to targeted direct mail outreach for this audience outlined in Appendix B.	• Information and/or overview of operator IM Program • ROW encroachment prevention	Annually
Proximity to asset with special characteristics	Direct Mail Postcard Notification	Residents and businesses or places of congregation located within 1000 ft of un-odorized transmission pipeline segments	Residents, businesses or places of congregation located within 1000 ft of an un-odorized transmission pipeline segment	• Landowners/ residents • Tenants • Farmers • Businesses • Schools • Places of worship • Hospitals or other medical facilities • Prisons • Day-care facilities • Senior centers	1. GIS department creates Shape files containing the geographic boundaries using centerline data with a minimum distance of 1000 ft from an un-odorized transmission pipeline. 2. PG&E contracts with a third-party vendor to create a mailing list using the Shape files provided by the GIS department. The vendor utilizes parcel data and other available data sources and formats the mail list per USPS standards. 3. Mailing addresses are verified by a third-party vendor using available USPS databases before mailing to ensure accuracy and deliverability. Validation includes the identification of any currently USPS-identified vacant properties that should be removed from the list before mailing. 4. The PAP administrator or designated third-party vendor is responsible for reviewing any undeliverable mail and provides this information to the list vendor for review. The PAP administrator determines if additional research is needed per Attachment 4, "Return Mail Analysis." 5. Addresses identified as vacant are annually re-assessed using the USPS database and, if occupied, a mailing is sent to that address.	Printed brochure contains information about the visual and auditory characteristics of a leak involving an un-odorized natural gas pipeline.	• Leak recognition and response	Annually
Public awareness effectiveness evaluation results; analysis of dig-in damage data	Direct Mail Brochure and E-campaign	Homeowner Associations	Homeowner Association officers and Homeowner Association managing agents responsible for filing a Statement by Common Interest Development Association (Form SI-CID) with the California Secretary of State	• Homeowner Association responsible officer • Homeowner Association managing agent • Condominium Association responsible officer	1. Request a list of Incorporated Associations from the California Secretary of State (www.sos.ca.gov/business.) 2. Filter the list to include records with addresses located within PG&E pipeline asset counties. 3. Review list and remove non-HOA categories of Incorporated Associations.	Information distributed by e-mail or targeted mail to Homeowner Associations contacts near transmission lines and in gas service territory including gas pipeline safety and damage prevention information to share with other members.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • Pipeline location information • How to get additional information • Availability of list of pipeline operators through NPMS	Annually

Appendix C, Supplemental Outreach Activities and Triggers
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Table C-1. General Affected Public (AP) (continued)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification	Supplemental Activity	Message(s)	Frequency
Regulatory requirement (49 CFR Part 192.16)	New Gas Customer Bill Insert and E-bill Pay Notification	New Gas Customers	Customers requesting new gas service from PG&E	• PG&E gas customers who receive a bill from PG&E	Contact information for all new gas customers is maintained in PG&E CIS. Customer accounts are maintained at the account level and include a billing address, premise address, e-mail (if available) and meter identification number.	New gas customers receive a gas safety bill insert or e-bill pay link with gas pipeline safety information and information regarding customer-owned lines within 90 days of a service turn-on.	• Customer responsibility to maintain "customer-owned pipelines" • Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • Leak recognition and response • How to get additional information	Every 90 days
Analysis of percentage of third-party damage caused by homeowners without a valid One Call ticket; survey feedback indicating levels of awareness of 811 within the affected public audience	811 Mass Media Campaign	Affected Public (adults 18+ are primary target audience); All Audiences (incremental reach)	Men and women who are 18+ and reside in PG&E asset counties	• Men 18+ • Women 18+	Media buyers use demographic data provided by media outlets to select appropriate coverage targeting men and women 18+ in PG&E asset counties.	Mass media campaigns promoting 811, press releases, ongoing media relations conducted by PG&E and through collaborative industry outreach	• Damage prevention awareness • One-call requirements	Annual based on media plan
Analysis of third-party damage data and percentage of damages caused without a valid One Call ticket	Service Center Signage	Affected Public	Individuals who visit a PG&E service center	• PG&E customers • Non-customers who visit a service center • PG&E personnel who work in a service center	Individuals who visit or work at a PG&E service center	811 awareness is promoted using signage in the lobby of PG&E customer service centers. Content may change throughout the year.	• Damage prevention awareness • One-call requirements	Continuous
Specific local situations, questions and/or incidents	Face-to Face and Phone Calls	Affected Public	Individuals who call PG&E with gas safety questions or who schedule an appointment with a gas service representative	• PG&E customers • Non-customers who call PG&E	Individuals who call PG&E or who request an appointment with a gas service representative	Gas service representatives and call center representatives communicate with customers regarding safety questions during on-site appointments and when customers call PG&E with safety questions.	Dependent on caller questions	Continuous

Appendix C, Supplemental Outreach Activities and Triggers
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Table C-1. General Affected Public (AP) (continued)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification	Supplemental Activity	Message(s)	Frequency
Specific local situations, questions and/or incidents; analysis of third-party dig-in damage; M&C activity	Community Events and Open Houses	Affected Public	Customers and non-customers who attend open house meetings or events	• PG&E customers • Non-customers who attend open house meetings or events	PG&E conducts open houses and community events in communities where PG&E has pipeline assets.	PG&E personnel communicate pipeline safety messages during community events, such as local farm shows, community fairs or other PG&E sponsored events, as well as open houses focusing on topics such as hydrostatic testing, maintenance or replacement projects and other topics of local interest. Brochures, calendars, key chains, scratch-and-sniff cards, pens and other giveaway items containing PG&E emergency contact information or USA information distributed during face-to-face meetings and community events.	• Dependent on local issues/questions • Damage prevention awareness • One-call requirements • Construction/maintenance projects • Leak recognition and response	Continuous
Unique asset with special safety concerns	Safety Signage	CNG Filling Station Customers	Customers approved to use CNG filling stations	• Commercial or municipal customers with CNG fleet vehicles	PG&E maintains a list of commercial and municipal customers.	Safety signage posted at CNG Filling Stations	• Damage prevention awareness • One-call requirements • Awareness of hazards and prevention measures • Emergency response procedures	Continuous
Decrease third-party dig-ins; increase location awareness; increase leak recognition and response	Gas and Electric Safety Classroom Materials	School teachers in distr bution service and transmission assets who request safety materials	K-8 teachers in education institutions located in PG&E asset counties	• Teachers (K-8)	Culver Co. creates a list of teachers based on areas where PG&E has assets.	Natural gas and electric safety educational materials are offered for free to teachers in elementary schools. Materials are promoted through targeted direct-mail outreach and provided by mail when requested.	• Damage prevention awareness • One-call requirements • Leak recognition and response • Pipeline location information • How to get additional information	Continuous
Significant maintenance or construction activities	Construction and Maintenance Notification	Affected Public	Residents, businesses and places of congregation where PG&E is conducting maintenance on PG&E system	• Customers and non-customers in impacted geographic area	Contacts are identified based on the area where PG&E is performing M&C projects in close proximity to the affected public.	The department responsible for communication outreach selects the most effective way to contact the affected public prior to any significant maintenance or construction activity. Outreach typically includes letters, door hangers, phone calls or personal contact.	• Any planned major maintenance/construction activity	Dependent on specific local situations
Public awareness effectiveness evaluation results (preference indicated for electronic communication methods)	Pipeline Safety Website Content	Affected Public	Customers and non-customers who visit www.pge.com pipeline safety web pages	• PG&E website visitors	Customers and non-customers who elect to visit www.pge.com pipeline safety web pages	PG&E maintains a website at www.pge.com with relevant safety and damage prevention information included in various pages throughout the site. The web site is promoted as a resource for additional safety information in other outreach materials as well as search engines.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • Pipeline location information • How to get additional information	Continuous

Appendix C, Supplemental Outreach Activities and Triggers
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Table C-1. General Affected Public (AP) (continued)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification	Supplemental Activity	Message(s)	Frequency
Unique asset with special safety communication needs; regulatory requirement for supplemental message	Compressor Station and Gas Storage Facility Brochures	Residents, businesses, or places of congregation located within 1000 ft of compressor stations and gas storage facilities	Residents, businesses or places of congregation located within 1000 ft of a compressor station or a gas storage facility	• Landowners/ residents • Tenants • Farmers • Businesses • Places of worship • Hospitals or other medical facilities • Prisons • Day-care facilities • Senior centers • Universities/ colleges	1. GIS department creates Shape files containing the geographic boundaries using centerline data with a distance of 1000 ft from a gas storage facility or compressor station. 2. PG&E contracts with a third-party vendor to create a mailing list using the Shape files provided by the GIS department. The vendor utilizes parcel data and other available data sources and formats the mail list per USPS standards. 3. Mailing addresses are verified by a third-party vendor using available USPS databases before mailing to ensure accuracy and deliverability. Validation includes the identification of any currently USPS-identified vacant properties to be removed from the list before mailing. 4. The PAP administrator or designated third-party vendor is responsible for reviewing any undeliverable mail and provides this information to the list vendor for review. The PAP administrator determines if additional research is needed per Attachment 4, "Return Mail Analysis." 5. Addresses identified as vacant are annually re-assessed using the USPS database and, if occupied, a mailing is sent to that address.	Targeted outreach is sent by direct mail to residents and businesses	• Special incident response notification and or evacuation measures if appropriate to product or facility • Information and/or overview of operator IM Program • ROW encroachment prevention • Any planned major maintenance/ construction activity • Information and/or overview of operator IM Program • Facility purpose, pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call requirements • Leak recognition and response • Pipeline location information • How to get additional information	Annually
CPUC audit recommendation (GA2013-28 Public Awareness Program)	Positive Response Notification Safety Message	Affected public who request a One Call ticket for a project near PG&E underground infrastructure and who receive a positive notification from PG&E One Call ticket management system	Affected public who request a One Call ticket for a project near PG&E underground infrastructure and who receive a positive notification from PG&E One Call ticket management system	• Landowners/ residents • Tenants • Farmers • Businesses • Places of worship • Hospitals or other medical facilities • Prisons • Day-care facilities • Senior centers • Universities/ colleges	Excavators who receive a positive response notification from PG&E as part of the One Call ticket management process	Reminder to hand dig within tolerance zone is included in positive response message.	• Damage prevention awareness • One Call requirements	Continuous

Appendix C, Supplemental Outreach Activities and Triggers
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Table C-1. General Affected Public (AP) (continued)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification	Supplemental Activity	Message(s)	Frequency
Historical incident data and cross bore identification program data	Cross bore Education	PG&E Gas and electric customers	• Residents and businesses who reside within PG&E service territory and receive gas and electric bills from PG&E either by mail or electronically	• PG&E residential gas and electric customers • PG&E gas and electric commercial or large industrial customers, critical facility customers (hospitals, nursing homes, colleges, universities, technical colleges), agriculture customers	Contact information for all active gas and electric customers is maintained in PG&E CIS. Customer accounts are maintained at the account level and include a billing address, premise address, email (if available) and meter identification number.	• Mailed bill inserts are sent to gas and electric customers • A link to view the bill insert is included in the e-mail sent to electronically billed customers and can be accessed from PG&E website. • Customers who have provided an email address also receive a separate e-mail campaign with safety information	• Awareness of hazards • Damage prevention awareness	Annually
Agreement between Congresswoman Jackie Speier and PG&E President Chris Johns	Direct Mail Campaign	Residents, businesses located within 2000 ft of transmission pipelines	Residents and businesses located within 2000 ft of a transmission pipeline	• Landowners/ residents • Tenants • Farmers • Businesses • Schools • Places of worship • Hospitals or other medical facilities • Prisons • Day-care facilities • Senior centers	1. GIS department creates Shape files containing the geographic boundaries using centerline data with a distance of 2000 ft from a gas storage facility or compressor station. 2. PG&E contracts with a third-party vendor to create a mailing list using the Shape files provided by the GIS department. The vendor utilizes parcel data and other available data sources and formats the mail list per USPS standards. 3. Mailing addresses are verified by a third-party vendor using available USPS databases before mailing to ensure accuracy and deliverability. Validation includes the identification of any currently USPS-identified vacant properties to be removed from the list before mailing. 4. The PAP administrator or designated third-party vendor is responsible for reviewing any undeliverable mail and provides this information to the list vendor for review. The PAP administrator determines if additional research is needed per Attachment 4, "Return Mail Analysis."	• Letter and a companion gas safety brochure are mailed to identified businesses and residents. Refer to targeted direct mail and bill insert outreach for this audience outlined in Appendix B.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • One-call Requirements • Leak recognition and response • Pipeline location information • How to get additional information • Availability of list of pipeline operators through NPMS	Every 3 years

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Table C-2. Emergency Response Officials (ER)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification Process	Supplemental Activity	Message(s)	Frequency
Regulatory requirement	Supplemental Messages	Emergency Officials in Transmission Asset County	Local, state, or regional officials, agencies and organizations with emergency response and/or public safety jurisdiction located in counties having gas transmission pipelines	• Fire departments • Police/sheriff departments • Local Emergency Planning Commissions (LEPCs) • Emergency Management Agencies (EMAs) • 911 Centers or Public Safety Access Points (PSAP)	1. PAP manager identifies counties with gas assets. 2. A third-party vendor (PAPA) identifies the emergency officials within each county using a classification under the applicable U.S. Government, Standard Industry (SIC) codes, and the North American Industry Classification (NAICS) codes. The applicable SIC and NAICS Codes are listed in program documentation provided by PAPA. 3. Emergency officials are also identified using commercially available data sources obtained from the National Public Safety Information Bureau. National Public Safety Information Bureau updates their data annually through phone calls to verify accuracy of contact information. InfoUSA is also used as a second source of data for agency locations.	Printed brochure contains information about PG&E IM Program and activities. Refer to targeted direct mail outreach for this audience outlined in Appendix B.	• Provide information and or overview of integrity measures undertaken • Availability of IM plans	Annually
Construction maintenance notification	Supplemental Messages	Emergency Officials in Transmission Asset County	Impacted local, state or regional emergency officials based on geographic scope of project	• Fire departments • Police/sheriff departments • Local Emergency Planning Commissions (LEPCs) • Emergency Management Agencies (EMAs) • 911 Centers or Public Safety Access Points (PSAP)	Emergency officials are identified based on the area where PG&E is performing M&C projects.	The department responsible for support communication outreach selects the most effective way to contact emergency officials prior to any significant maintenance or construction activity. Outreach typically includes face-to-face meetings or phone calls.	• Any planned major maintenance/ construction activity	Dependent on specific local situations
Unique asset with special safety communication needs	Supplemental Messages	Emergency Officials in Transmission Asset County or near Storage Facilities or Compressor Stations	Local, state, or regional officials, agencies and organizations with emergency response and/or public safety jurisdiction located in counties having gas transmission pipeline, gas gathering pipeline, gas storage facility, or compressor station	• Fire departments • Police/sheriff departments • Local Emergency Planning Commissions (LEPCs) • Emergency Management Agencies (EMAs) • 911 Centers or Public Safety Access Points (PSAP)	Emergency officials are identified based on their proximity to the unique asset or pipeline segment.	PG&E emergency preparedness department conducts tabletop exercises or drills to review special emergency procedures.	• Special emergency procedures (if applicable)	Dependent on specific local situations

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Table C-2. Emergency Response Officials (ER) (continued)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification Process	Supplemental Activity	Message(s)	Frequency
Regulatory requirement	Face-to-Face	Emergency Officials in Asset County	• Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located within the gas service territory • Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located in counties having a gas transmission pipeline, gas gathering pipeline, gas storage facility or compressor station	• Fire departments • Police/sheriff departments • Local Emergency Planning Commissions (LEPCs) • Emergency Management Agencies (EMAs) • 911 Centers or Public Safety Access Points (PSAP)	Public Safety Specialists contact emergency response agencies and work with them to plan face-to-face meetings. Agency contacts help invite other emergency response officials to attend.	Public Safety Specialists meet with emergency officials to develop partnerships with emergency response agencies in the prevention of and emergency response preparation for gas pipeline incidents. Face-to-face meetings include the flipbook and resource guide as handouts.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information • Potential hazards • Pipeline location information and availability of NPMS • Gathering pipeline location • Specific description of products transported and any potential special hazards	Continuous
Regulatory requirement	PAPA Capability Assessment	Emergency Officials in Asset County	• Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located within the gas service territory • Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located in counties having a gas transmission pipeline, gas gathering pipeline, gas storage facility or compressor station	• Fire departments • Police/sheriff departments • Local Emergency Planning Commissions (LEPCs) • Emergency Management Agencies (EMAs) • 11 Centers or Public Safety Access Points (PSAP)	1. PAP manager identifies counties with gas assets. 2. A third-party vendor (PAPA) identifies the emergency officials within each county using a classification under the applicable U.S. Government, Standard Industry codes (SIC), and the North American Industry Classification (NAICS) codes. The applicable SIC and NAICS codes are listed in program documentation provided by PAPA. 3. Emergency officials are also identified using commercially available data sources obtained from the National Public Safety Information Bureau. National Public Safety Information Bureau updates their data annually through phone calls to verify accuracy of contact information. InfoUSA is also used as a second source of data for agency locations.	Printed brochure includes information about the capability assessment tool, form to complete and request to submit data. Refer to targeted direct mail outreach for this audience outlined in Appendix B.	• Assess emergency response capabilities	Annually

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Table C-2. Emergency Response Officials (ER) (continued)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification Process	Supplemental Activity	Message(s)	Frequency
Survey feedback requesting expanded emergency response information **Regulatory request (PHMSA bulletin requested that operators provide information from their emergency plan)**	Online Emergency Response Portal	Emergency Officials in Asset County	• Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located within the gas service territory • Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located in counties having a gas transmission pipeline, gas gathering pipeline, gas storage facility or compressor station	• Fire departments • Police/sheriff departments • Local Emergency Planning Commissions (LEPCs) • Emergency Management Agencies (EMAs) • 911 Centers or Public Safety Access Points (PSAP)	Emergency officials are notified about the portal during face-to-face meetings, through the www.pge.com website and in printed materials included the flipbook.	Emergency Official Online Portal – Includes publicly-available resources with contact information, the ability to order materials, and view list of upcoming first responder workshops. Password-protected pages allow emergency officials to view and download gas transmission maps, download a copy of PG&E Gas Emergency Response Plan and access contact information for key Gas T&D M&C contacts and the Public Safety Specialists. Materials available for order from the portal include: "Responding to Utility Emergencies" training books, resource guide and flipbook. Materials linked directly from the portal include: NPMS, PAPA Emergency Response Guidebook and "Pipeline Emergencies" training materials.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information • Potential hazards • Pipeline location information • Gathering pipeline location and purpose • Specific description of products transported and any potential special hazards	Continuous
Survey feedback regarding percentage of agencies with confirmed standard operating procedures in place to respond to a pipeline emergency	Emergency Drills	Emergency Officials in Asset County	• Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located within the gas service territory • Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located in counties having a gas transmission pipeline, gas gathering pipeline, gas storage facility or compressor station	• Fire departments • Police/sheriff departments • Local Emergency Planning Commissions (LEPCs) • Emergency Management Agencies (EMAs) • 911 Centers or Public Safety Access Points (PSAP)	Emergency officials are invited based on proximity to identified drill location.	Emergency Drills – Field locations invite local emergency officials to participate in mock emergency drill exercises	• Awareness of hazards and prevention measures undertaken • Emergency preparedness communications • How to get additional information • Potential hazards • Pipeline location	Dependent on specific local situations

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Table C-3. Professional Excavators (EX)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification Process	Supplemental Activity	Message(s)	Frequency
Regulatory requirement	RP-1162 Supplemental Messages	Excavators in California digging near transmission pipelines	Companies performing or directing excavation work in the State of California and having a California business address	• Contractors • Construction companies • Excavation equipment rental companies • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Public works officials	1. A third-party vendor (PAPA) identifies Excavator contacts with mailing addresses in California using SIC and NAICS codes. The applicable SIC and NAICS codes are listed in program documentation provided by PAPA. Lists are updated annually. 2. PAPA utilizes a combination of commercial data sources (Info USA and USA Data) and public data (licensing boards, trade associations) to identify excavator, contractor, agriculture and land developer contacts.	Printed brochure includes pipeline purpose, prevention measures and reliability messages. Refer to targeted direct mail outreach for this audience outlined in Appendix B.	• Pipeline purpose, prevention measures and reliability	Annually
One Call ticket regarding excavation activity within 5 ft of a PG&E transmission pipeline	Standby meeting with a PG&E representative during excavation	Excavators in California digging near PG&E transmission pipelines	Excavators with One Call ticket for project within 5 ft of a PG&E transmission pipeline	• Contractors • Construction companies • Excavation equipment rental companies • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Public work officials	Excavators digging within 5 ft of PG&E transmission pipeline are identified through the One Call ticket process.	Personnel are on-site for a standby meeting to observe excavation procedures when an excavator is digging within 5 ft of a transmission pipeline.	• Damage prevention awareness • One Call requirements	Continuous
Dig-in data analysis identifying excavation-related trends causing damages	Face-to-Face Meetings	Excavators in California	Excavators who dig near PG&E pipelines	• Contractors • Construction companies • Excavation equipment rental companies • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Public work officials	Excavators are identified using information from One Call ticket requests, dig-in damage reports and state licensing board list.	Face-to-face meetings and training sessions for excavators/contractors led by PG&E	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention awareness • Leak recognition and response • One Call requirements • How to get additional information	Continuous
Historical incident data and cross bore identification program data	Cross bore Education	Plumbers in California	Companies performing or directing work related to sewer laterals and mains.	• Plumbers • Sanitation services	A third-party vendor identifies licensed plumbers and sanitation services in California using SIC and NAICS codes, commercial data sources (Info USA and USA Data) and public data (licensing boards, trade associations).	Targeted direct mail materials containing safety information regarding how to identify potential cross bores, the hazards associated with cross bores and to encourage them to inspect the line for potential cross bores.	• Awareness of hazards • Damage prevention awareness	Annually

Appendix C, Supplemental Outreach Activities and Triggers
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Table C-3. Professional Excavators (EX) (continued)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification Process	Supplemental Activity	Message(s)	Frequency
Dig-in data analysis identifying excavation-related trends causing damages	Excavation Safety Video and Training Materials	Excavators in California	Companies performing or directing excavation work in the State of California and having a California business address	• Contractors • Construction companies • Excavation equipment rental companies • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Public work officials	A third party vendor identifies excavator contacts in PG&E asset counties using SIC and NAICS codes, commercial data sources (Info USA and USA Data) and public data (licensing boards, trade associations).	PG&E safety video "Excavation Safety" and "Worker Beware" safety educational materials are offered for free to excavators. Materials are promoted through targeted direct mail outreach.	• Damage prevention awareness • One Call requirements • Leak recognition and response • Potential hazards • Pipeline purpose and reliability	Continuous
Dig-in data analysis identifying excavation-related trends causing damages	Mass Media Campaign	Excavators in California	Companies performing or directing excavation work in the State of California and having a California business address	• Contractors • Construction companies • Excavation equipment rental companies • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Public work officials	Media buyers use demographic data provided by media outlets to select appropriate coverage targeting excavators in PG&E asset counties	Mass media campaigns promoting 811, press releases and ongoing media relations	• Damage prevention awareness • One Call requirements	Annually based on media plan
Dig-in data analysis identifying excavation-related trends causing damages; survey data analysis	One Call Awareness and Education Events	Excavators in California	Companies performing or directing excavation work in the State of California and have a California business address	• Contractors • Construction companies • Excavation equipment rental companies • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Public work officials	USA North and USA South (Dig Alert) utilize their one call ticket database to identify excavators to invite to events.	USA – One Call Events: Safety Awareness for Excavators (SAFE) events. PG&E 811 Call Before You Dig Seminars	• Damage prevention awareness • One Call requirements	Continuous
Dig-in data analysis identifying excavation-related trends causing damages	Activity Specific Targeted Outreach	Excavators who have damaged PG&E pipelines within a rolling 12 month period	Excavators in California who are more likely to damage PG&E pipelines based on the activities they conduct	• Fence building companies • Landscapers • Water, sewage, plumbing, sanitation	Varies depending on audience	Annually analyze and identify geographic areas with high numbers of dig-ins within the last year. Develop outreach strategies based on identified trends within identified geographic areas. Examples of outreach may include face-to-face meetings with excavation company personnel, 811 workshops, presence at local community events and a targeted direct mail piece for landscapers and fencers licensed in California.	• Damage prevention awareness • One Call requirements	Annually

Appendix C, Supplemental Outreach Activities and Triggers
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Table C-3. Professional Excavators (EX) (continued)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification Process	Supplemental Activity	Message(s)	Frequency
Dig-in data analysis identifying excavation-related trends causing damages	Habitual Offenders Targeted Outreach	Excavators who have damaged PG&E pipelines within a rolling 12 month period	Excavators in California who damage PG&E pipelines more than once in a given period	• Contractors • Construction companies • Excavation equipment rental companies • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Public work officials	Habitual offenders are identified through analysis of dig-in damage data.	Damage prevention identifies habitual offenders and develops communications and educational workshops for excavators who damage PG&E pipelines more than once in a given time period. Outreach may include letters, phone calls, targeted direct mail materials, training sessions, face-to-face meetings, e-mail campaigns or other communication strategies.	• Damage prevention awareness • One Call requirements	Continuous
CPUC audit recommendation (GA2013-28 Public Awareness Program)	Positive Notification Safety Message	Excavators in California who request a One Call ticket for a project near PG&E underground infrastructure and who receive a positive notification from PG&E One Call ticket management system	Excavators in California who request a One Call ticket for a project near PG&E underground infrastructure and who receive a positive notification from PG&E One Call ticket management system	• Contractors • Construction companies • Excavation equipment rental companies • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Public work officials	Excavators who receive a positive response notification from PG&E as part of the One Call ticket management process	Reminder to hand dig in tolerance zone is included in positive response message.	• Damage prevention awareness • One Call requirements	Continuous
Excavation companies performing excavation work on behalf of PG&E	Gold Shovel Standard	Excavators working on PG&E projects requiring excavation.	Excavators directly under contract with PG&E performing excavation-related work on behalf of PG&E.	• Construction companies • Pole test and treat companies • Tree removal companies • Landscaping companies • Fence installation companies • Concrete companies	PG&E requests for proposals (RFP) posted on its external website for work requiring excavation include specific requirements companies submitting proposals which include performing excavation work be Gold Shovel Standard certified at the time of submission.	A third party vendor certifies companies who have submitted an application for Gold Shovel Standard certification and submits the certification information to ISNetworld to be used by PG&E Sourcing Department as part of its proposal review process.	• Damage prevention awareness • One Call requirements	Continuous
Excavators observed by PG&E Personnel and contractors who have violated the One Call Law	811 Ambassador Program	Excavators and homeowners working in California	Excavators and homeowners performing excavations near PG&E underground assets	• Contractors • Construction companies • Timber companies • Fence building companies • Drain tiling companies • Landscapers • Homeowners	Personnel view excavation activities and call the Damage Prevention Hotline to report potential non-compliance with California One Call Law.	Dig-in Reduction Team (DiRT) members or Locate and Mark personnel are sent to the job site to determine compliance with California One Call Law. Non-compliance requires stopping excavation and taking corrective action prior to restarting excavation. Excavators and homeowners are provided excavation safety brochures.	• Damage prevention awareness • One Call requirements	Continuous

Appendix C, Supplemental Outreach Activities and Triggers
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Table C-4. Local Public Officials (PO)

Triggers	Trigger Strategy	Audience Impacted	Audience Definition	Audience Examples	Audience Identification Process	Supplemental Activity	Message(s)	Frequency
Regulatory requirement	RP-1162 Required Transmission Supplemental Messages	Public Officials in Transmission Asset Counties	• Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located in counties having a gas transmission pipeline, gas gathering pipeline, gas storage facility or compressor station.	• Planning boards • Zoning boards • Permit/licensing departments • Building Code Enforcement departments • City and county managers • Public and Government officials • Local governing councils • Public utility boards • Public street, road and highway departments (CalTrans)	1. PAP manager identifies counties with gas assets. 2. A third-party vendor (PAPA) identifies the Public Official contacts within each county using classification under the applicable U.S. Government, Standard Industry Classification (SIC) codes and the North American Industry Classification System (NAICS) codes. The applicable SIC and NAICS Codes are listed in program documentation provided by PAPA. Lists are updated annually. 3. PAPA also utilizes list provided by professional associations (such as the American Association of Planners). 4. Additionally, PG&E uses internal databases located in the Public Relations Department to communicate directly with local, state or federal public official as needed.	M&C messages are communicated prior to any significant maintenance or construction activity. Printed materials include information about HCAs, ROW encroachment and integrity measures. Refer to targeted direct mail outreach for this audience outlined in Appendix B.	• Information about designation of a High Consequence Area (HCA) or other factor unique to segment and summary of integrity measures undertaken • ROW encroachment prevention • Maintenance construction activity	Annual distribution of printed materials M&C communication is distributed continuously based on project schedule.
Dig-in data analysis identifying excavation-related trends causing damages; survey data analysis	Face-to-Face Meetings	Public Officials in Asset County	• Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located within the gas service territory. • Local, city, county and state officials and/or their staffs having land use and street/road jurisdiction located in counties having a gas transmission pipeline, gas gathering pipeline, gas storage facility or compressor station.	• Planning boards • Zoning boards • Permit/licensing departments • Building Code Enforcement departments • City and county managers • Public and Government officials • Local governing councils • Public utility boards • Public street, road and highway departments (CalTrans)	Internal databases with public official contacts are maintained by the public relations department.	Public Affairs meets with public officials to develop partnerships with communities and to increase awareness regarding pipeline safety, land use and planning, local issues and construction/maintenance projects.	• Pipeline purpose and reliability • Awareness of hazards and prevention measures undertaken • Damage prevention • How to get additional information	Continuous
Historical incident data and cross bore identification program data	Cross bore Education	Public Works Officials	Public Works Officials	• Water and sewage department contacts	A third-party vendor identifies licensed plumbers and sanitation services in California using SIC and NAICS codes, commercial data sources (Info USA and USA Data) and public data (licensing boards, trade associations). PG&E uses internal databases located in the Public Relations Department to identify appropriate public official contacts.	Targeted direct mail materials containing safety information regarding how to identify potential cross bores, the hazards associated with cross bores and to encourage them to inspect the line for potential cross bores. Face-to-face meetings are conducted with public officials.	• Awareness of hazards • Damage prevention awareness	Annually Dependent on specific local situations
Dig-in data analysis identifying excavation-related trends causing damages	Partnership with CSLB	CSLB Staff	CSLB staff who communicate with excavators in California and/or enforce state requirements for licensed contractors	• CSLB enforcement and communication contacts	Public Relations State Agency Relations maintains relationships with CSLB contacts. Dig-in data contains information regarding root causes for dig-ins and the responsible party.	Coordinate activities with the Contractor State Licensing Board (CSLB) to educate excavators about and enforce compliance with California excavation safety laws including publication of articles in CSLB publications for contractors and dig-in notifications to CSLB staff.	• Awareness of hazards and prevention measures undertaken • One Call requirements • Damage prevention awareness	Continuous

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Appendix D, Acceptable Methods for Assessment of Recall and Understandability

Table D-1. Acceptable Methods for Assessment of Recall and Understandability

Audience	Acceptable Assessment Methods
Affected Public: LDC Gas Customers and non-gas customer residents living within the gas service territory	Random Sample Survey: Telephone surveys utilizing Random Digit Dialing (RDD) sampling methods to reach PG&E gas customers and non-gas customer residents living within the gas service territory. Respondents are screened to ensure the person in the household completing the interview is responsible for reviewing/paying the utility bill and is at least 18 years old. The survey will include enough responses to yield statistically valid results. The margin of error for the aggregate results should not exceed +/-5% at the .95 confidence level. Customer Brand Health Survey (CBHS): Telephone survey of randomly selected residential and business customers. CBHS is an internal customer satisfaction survey conducted quarterly.
Affected Public: Located adjacent to Gas Transmission Pipelines, Gas gathering Pipelines, Gas Storage Facilities, or Compressor Stations	Random Sample Survey: Mail survey sent to a random sample of residential and business addresses including farmers and schools located adjacent to PG&E pipelines. The survey will include enough responses to yield statistically valid results. The margin of error for the aggregate results should not exceed +/-5% at the .95 confidence level.[1]
Emergency Officials	Random Sample Survey: A telephone survey conducted with a random sample of emergency officials located within the PG&E asset counties. The survey will include enough responses to yield statistically valid results. The margin of error for the aggregate results should not exceed +/-10% at the .95 confidence level.[2] Participation in the PAPA National Industry Survey: In-depth telephone interviews conducted with a random sample of emergency officials who receive PAP materials distributed by PAPA. The survey will include enough responses to yield statistically valid results. The margin of error for the aggregate results should not exceed +/-5% at the .95 confidence level.[1] Emergency Official Meeting Survey: Feedback is collected at meetings with groups of emergency officials. This is a census-style approach measuring feedback from all attendees.
Public Officials	Random Sample Survey: A telephone survey conducted with a random sample of local public officials within PG&E asset counties. The survey will include enough responses to yield statistically valid results. The margin of error for the aggregate results should not exceed +/-10% at the .95 confidence level.[1] Participation in the PAPA National Industry Survey: In-depth telephone interviews conducted with a random sample of public officials who receive PAP materials distributed by PAPA. The survey will include enough responses to yield statistically valid results. The margin of error for the aggregate results should not exceed +/-5% at the .95 confidence level.[1]
Excavators	Random Sample Survey: A telephone survey conducted with a random sample of excavators working in PG&E asset counties. The survey will include enough responses to yield statistically valid results. The margin of error for the aggregate results should not exceed +/-7.5% at the .95 confidence level.[1] Participation in the PAPA National Industry Survey: In-depth telephone interviews conducted with a random sample of excavators who receive PAP materials distributed by PAPA. The survey will include enough responses to yield statistically valid results. The margin of error for the aggregate results should not exceed +/-5% at the .95 confidence level.[1]

Notes:

1. In June 2013 PG&E and seven other large distribution gas operators founded a workgroup comprised of PAP administrators, now formalized as the Distribution Public Awareness Council (DPAC). One of the DPAC initial projects focused on developing a consensus industry standard for implementing the PAP measurement requirements in API 1162 and PAPE Form 21 including guidance for acceptable margin of error when sample survey data is collected and utilized to evaluate program effectiveness and track program improvement. The final report and standard from the workgroup as published November 21, 2014.
2. Margin of error thresholds are determined based on the total size of the population and in conjunction with advice from research firms selected to help with the survey and internal subject matter experts within the Customer Care organization.

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Appendix E, Desired Behavior by Stakeholder

Table E-1. Desired Behavior by Stakeholder

Stakeholder	Description of Desired Behaviors	Examples of Acceptable Survey Questions or Operational Data
Affected Public	• Actions demonstrating they are able to appropriately respond to a potential pipeline problem (i.e. leave the area then call 911 and PG&E to report a leak, avoid using mechanical equipment or electrical devices near a possible leak) • Demonstrate that they take/would take actions to protect pipeline infrastructure (i.e. call to report unauthorized digging, call 811 before digging)	• "What would you likely do if you suspected a leak/break?" • Calls to PG&E to report a leak • "What actions would you be likely to take prior to digging?" • "How often do you call 811 before you dig?"
Emergency Officials	• Demonstrate readiness to appropriately respond to a potential pipeline problem (i.e. have standard operating procedure in place to respond, have conducted a drill or training to practice their standard operating procedure, are confident in their ability to respond to a pipeline emergency in their jurisdiction)	• "Have you conducted any practical training including drills and exercises to deal with a pipeline break or leak?" • "On a scale of 1-10 where 10 is totally confident and 1 is not confident: how confident are you in your ability to appropriately respond to a pipeline emergency in your jurisdiction?" • PG&E internal incident report observations regarding emergency officials response protocol, procedures, timing and any issues identified • Post drill report observations regarding emergency official response
Excavators	• Demonstrate following safe excavation procedures near pipelines (i.e. call 811 before digging, wait to have lines marked, use appropriate tools when digging near pipelines) • Demonstrate knowledge of what to do if they damage a pipeline while excavating (i.e. leave the area and call 911 and PG&E if the pipeline is leaking, do not operate mechanical equipment, call PG&E or 811 to report damage)	• "On a scale of 1-10 where 10 is totally confident and 1 is not confident: how confident are you in your ability to "recognize" temporary facility markings?" • "How often do you call 811 to have lines marked before initiating excavation projects?" • "How often do you use hand tools or vacuum tools when excavating near underground pipelines?" • Incident report observations
Public Officials	• Demonstrate/indicate location of pipelines is considered during land use and permitting decision-making process (i.e. access NPMS or PG&E pipeline map, contact PG&E to discuss projects and impact on pipelines) • Demonstrate following safe excavation procedures near pipelines (i.e. call 811, wait the required time to have lines marked, use appropriate equipment when digging near pipelines)	• Calls to engineering or planning group • One-Call ticket data • Incident report observations • "How often do you check the location of nearby pipelines or other underground utilities when reviewing applications for permits?"

PART 1: OVERVIEW

a) Best Practice: 25

b) Status: Complete with continuous improvement R&D

Dig-Ins / Company Standby Monitors

Dig-Ins – 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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E currently requires stand-by monitors to be present when excavation work is done within 10 feet of gas transmission lines. This is communicated to excavators through the Underground Service Alert (USA) Ticket process; the locator, upon identifying the transmission facility, arranges a field meet with the excavator to discuss the schedule and stand-by process. PG&E provides this service (locating, field meet, and stand-by during excavation) free of charge. See the supplemental section below for details on Utility Procedure TD-5811P-1300, section 6.4

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E plans to utilize its existing process as mentioned in question a) above as it adheres with the BP.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

California Government Code 4216 requires PG&E to arrange a field meet when a USA Ticket is requested for work within 10 feet of a gas transmission pipeline. PG&E's current practice provides, in addition to the field meet, a standby which exceeds the regulation and adheres to the BP.

e) What technology is required to implement the best practice and why?

No additional technology is required, however, PG&E's existing process includes continuous improvement for research and development (R&D) opportunities to be developed.

f) Will work require additional personnel and/or contract support? If so, please provide details.

No additional personnel are required.

g) What changes to existing operations are required? How will those changes be implemented?

No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.

Procedures are in place.

i) Timeline for implementation (Milestones):

Compliance with this BP is complete.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:

No costs are associated with this BP.

k) Identify any cost benefits from this BP, when cost estimates are known:
See question j) above.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
See question j) above.

m) Anticipated Emissions Reductions from this BP:
No emission reductions are anticipated due to this BP.

2015 Baseline Emissions affected, where known: See PG&E's response to question m) above.
Not applicable, see question m) above.

n) Calculation Methodology:
Not applicable, see question m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that results, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
None.

d) Other:
See attached for the standard used (BP25_ATCH01).

Pacific Gas and Electric Company®

Utility Procedure: TD-5811P-1300
Publication Date: 01/30/2018; Effective Date: 01/30/2018 Rev: 0c

Responding to an Underground Service Alert (USA) Ticket

SUMMARY

This utility procedure provides guidance for Pacific Gas and Electric Company (PG&E or the Company) personnel responding to underground service alert (USA) tickets generated through a one-call system and identifying standby and field meet requirements.

Level of Use: Informational Use

TARGET AUDIENCE

Personnel and supervisors that locate underground facilities for any reason. These groups include

Locate and mark; gas maintenance and construction; gas transmission and distribution construction; applied technology services (ATS); gas pipeline operations and maintenance; quality management; gas distribution engineering and design; pipeline services; gas field support, and all personnel who mark an underground facility for any reason.

SAFETY

Specific hazards impacting this work include the following conditions:

- Electrical shock from contacting live electric facilities
- Construction activities
- Asphyxiation due to oxygen displacement
- Explosion or ignition of escaping gas
- Unrestrained animals at customer premises
- Tripping and slipping hazards
- Inadequate barriers from vehicular traffic
- Vegetation, including poison oak

Failure to conduct a thorough site assessment of PG&E and third-party underground facilities poses a risk to PG&E personnel, the public, and underground facilities.

Without accurate surface markings during excavation projects, construction equipment may strike buried facilities, injuring PG&E personnel or the public, and/or damaging the underground facilities.

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BEFORE YOU START

Appropriate training and equipment inspection must be completed prior to using any PPE or tools for locating electric facilities.

Personal protective equipment (PPE): Personnel performing this procedure must have the minimum PPE per the Gas Operations PPE Matrix.

Tools: In addition to PPE, ensure the following tools are available:

- Electronic device to read and respond to USA tickets
- Camera

Operator qualifications (OQs): This procedure contains covered tasks requiring qualifications. Consult the PG&E Gas Qualifications Task List or contact the Gas Qualifications department for covered task information, including date available and effective dates.

Available PG&E Academy Training:

- GAS-0210, “Locate and Mark”
- GAS-0227, “Locate and Mark Ride Along”

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Responding to an Underground Service Alert (USA) Ticket

PROCEDURE STEPS

1 General Requirements

1.1 For additional information on PG&E locating activities, refer to the PG&E *Locate and Mark Field Training Guide* as needed.

1.2 For additional information on terms and definitions used by one-call systems, operators, and excavators, refer to the Dig Safe Act (California Government Code 4216) Excavation Law as needed.

2 Requesting a USA Ticket

2.1 Contact 8-1-1 to request a USA ticket. 8-1-1 can also be contacted electronically after normal operating hours at the USA North 811 Express web site or the Dig Alert Express web site, depending on location.

- All excavators performing an excavation must have an underground service alert (USA) ticket with a delineation.

3 Receiving and Reviewing Assigned USA Tickets

3.1 Locate and Mark supervisors assign work to locate and mark personnel as appropriate.

3.2 Locate and Mark personnel screen tickets as appropriate to determine appropriate actions for each ticket. Ticket examples may include the following:

1. Emergency tickets (emergency means a sudden, unexpected occurrence, involving a clear and imminent danger, demanding immediate action to prevent or mitigate loss of, or damage to, life, health, property, or essential public services)
2. Normal notice tickets (due in 2 working days, not including the day it was requested)
3. Follow-up, extension, or renewal tickets
4. Expired or misplaced tickets

Responding to an Underground Service Alert (USA) Ticket

3.2 (continued)

5. Tickets requested for design purposes – tickets with no scheduled excavation activities associated with them. The USA ticket process is not intended to be used for design purposes.

   a. Perform the following steps for ticket requests submitted for design purposes:

      (1) Provide the excavator with area Division PG&E Service Planning contact information to assist them.

      (2) Explain that USA ticket requests are not used for design purposes.

      (3) Contact a member of the Dig-in Reduction Team (DiRT) to discuss engineering or design tickets with the requestor.

6. Large or complicated tickets

   a. Discuss proposed excavation with excavator to determine scope of work and appropriate response and next steps.

3.3 Contact supervisor or senior gas compliance representative to request assistance in any of the following circumstances:

- Excavation is in heavy traffic
- Excavation is in an unsafe neighborhood
- Help is required from a corrosion mechanic
- Help is required from a qualified electric worker (QEW)

4 Reviewing USA Ticket Details

4.1 Review ticket descriptions for the following:

1. Information needed to perform the locate.
2. Accuracy of information from excavator.

4.2 Review ticket to determine if all required tasks detailed on ticket can be completed by the due date.

4.3 IF a ticket cannot be completed by the due date and time,

THEN notify the local responsible locate and mark supervisor.

4.4 Refer to Table 1, “Actions to Take,” for appropriate actions to take in response to the listed conditions.

Responding to an Underground Service Alert (USA) Ticket

Table 1. Actions to Take

Condition	Action
The entire ticket cannot be completed by the due date because of excavation size	• Discuss options to phase the ticket with excavator. Phasing a ticket can only be performed once a site visit has been made and initial markings have been made. • Develop and document a plan to locate a different section, as needed, ahead of excavation activity
Ticket cannot be completed by the due date and a phased ticket is not appropriate	Contact excavator and attempt to set a mutually agreeable new start time and date for the USA ticket. This may be needed due to weather, access issues, assistance needed to complete locate, etc. A new start time and date can only be documented after the excavator agrees.
Ticket details do not match delineations at the excavation site	Contact the excavator to clarify. Document conversation with excavator. Practical delineations must be present before PG&E personnel place facility markings. Practical delineations are appropriate for the site and easily understood.
No practical delineations are present	Close the ticket or contact excavator to identify delineations. Practical delineations must be present before PG&E personnel place facility markings.
Delineations could be modified for clarity	Contact the excavator to clarify. Document conversation with excavator. Practical delineations must be present before PG&E personnel place facility markings.
Delineations identify an area larger than is needed	
A homeowner requested the USA ticket	Provide homeowner assistance in placing practical delineations.
Excavator is unavailable or cannot renegotiate	Immediately contact supervisor and document details in the USA ticket.

4.5 Refer to Utility Procedure TD-5811P-1100, “Locating Methods and Instruments,” for methods and equipment to complete locate tasks.

4.6 Refer to Utility Procedure TD-5811P-1200, “Locating and Marking Subsurface (underground) Facilities,” for locating and marking requirements, including proper marks.

4.7 Contact the excavator when a subsurface facility installation is fully or partially embedded in the pavement and not visible from the surface, and perform the following steps before pavement removal:

1. Communicate the need to protect the facility.
2. Determine a plan of action to protect the facility and excavator
3. Document the plan in the USA ticket.

4.8 IF the USA ticket is a continual excavation ticket AND PG&E facilities conflict with the excavation area,

THEN perform a field meet with the excavator to determine a plan to protect the excavator, the facilities, and the facilities’ markings.

Responding to an Underground Service Alert (USA) Ticket

5 Responding to a USA Ticket

5.1 Take pictures of work area, including the following:

- Reference points (street signs, address, permanent landscaping, etc.)
- Beginning and end of delineated work area
- All marks placed in response to the USA ticket, including flags, whiskers, chalk, paint, etc.
- Close-up pictures, including necessary details
- Distance pictures, including scope of excavation

5.2 Attach all pictures to the USA ticket.

5.3 Include the following information for each USA ticket, when appropriate:

- All conversations, including name and contact information of excavator representative
- All agreements made (phased ticket, new start time, etc.)
- Additional facility information shared with excavator (use of map measurements to place markings, existence of abandoned facilities when known, etc.)

5.4 Select the appropriate ticket response from available options.

6 Identifying the Need for a Field Meet or Standby

NOTE

During a site visit, the responsible locator for PG&E physically visits the delineated area of the excavation and compares information from the USA ticket to the actual excavation, locates and marks affected facility locations, and determines whether or not a USA ticket should be phased. This is an opportunity for a locator to determine the scope of a USA ticket request, answer specific concerns and questions before locating and marking facilities, and build a positive relationship with excavators.

6.1 A site visit is needed for any of, but not limited to, the following:

- Phasing a ticket because locate and mark cannot be completed before due date
- Determining excavation schedule for a large project
- Gaining access to locate and mark work areas
- Obtaining critical information regarding work area
- Addressing safety concerns for locate and mark personnel
- Discussing safe excavation practices
- Placing marks at an excavation site

6.2 Refer to Utility Procedure TD-5811P-301, Attachment 1, “Handling Excavators Working Unsafely,” for information on working with excavators that are working unsafely.

6.3 Field Meets

NOTE

A field meet is a documented prearranged on-site meeting between the locator and excavator to inform the excavator of the location of Company facilities and danger posed to those facilities, and to clarify any questions the excavator has for the Company regarding its facilities or the timetable for the excavation. Locate and mark personnel, excavator, a standby person, and anyone whose role is important to the protection of PG&E facilities during an excavation may be included.

1. Use the field meet to communicate to the excavator any possible threat of damage to PG&E underground facilities.

2. A field meet is needed for any of the following:

   - Excavation is within 10 ft of a critical or high priority facility subsurface installation.
   - Agricultural activities where grading, discing, ripping, or other disruptive physical work may threaten underground facilities.
   - Planned construction methods or practices are likely to threaten the integrity of underground PG&E facilities.
   - Excavation activities may impact overhead facilities (e.g., cranes, booms, drilling rigs).
   - Blasting activity is within 50 ft of the nearest edge of a PG&E facility.
   - Planned boring will intersect a critical or high priority PG&E facility location.
   - Pipe bursting (Refer to Utility Procedure TD-5811P-301, “Performing Standby,” to determine if a standby is also required).
   - Heavy equipment use within 10 ft of critical or high priority PG&E facility location.
   - Auger bore, hammer bore, or horizontal directional drilling use within 10 ft of critical or high priority PG&E facility location.
   - Rock wheeling use within 10 ft of critical or high priority PG&E facility location.

6.3 (continued)

3. Attempt to perform a field meet with any non-compliant excavator performing excavation activities. A non-compliant excavator is someone who is known to have worked in an unsafe manner.

4. Do the following when a field meet is needed,

   - Communicate with excavator regarding the need for a field meet.
   - Schedule field meet with excavator.
   - Perform the field meet.

5. For PG&E excavators, or contractors performing work on behalf of PG&E, field meets can be documented as follows:

   - USA ticket hard copy
   - Pre-Dig Verification Form (TD-4412P-05-F02) or Job Site Safety Analysis (JSSA) for Tailboard Briefing Form (TD-4414P-01-F01)

6. For excavators that are not PG&E personnel or contractors performing work on behalf of PG&E, document the following in USA ticket response:

   a. All actions taken

   b. All communications with excavator including:

      - Name and phone number of excavator contact person
      - Location and date of field meet
      - Reason for field meet

   c. All forms of communications used (e.g., phone, email, fax)

7. Refer to TD-5811P-301 for criteria, requirements and actions to take while performing a standby.

6.4 Standby Requirements

NOTE

Standby exceptions are listed in Section 6.4.2. All other requirements remain in effect (i.e., calling 811 and field meets).

1. A standby person is needed for any of the following reasons:
   - Excavations within 5 ft of the nearest edge of a critical or high priority facility (see Step 6.4.2 for exception)
   - Boring activity crosses a critical facility
   - Boring activity is parallel to a critical or high priority facility, within 10 ft of the nearest edge of the facility
   - Blasting activity occurs within 50 ft of the nearest edge of a facility
2. A standby is **not** required at a critical facility in the following situations:
   a. Exposing air to soil transitions - ALL of the following criteria must be met.
      (1) Critical facility is a transmission station, transmission span or a distribution regulator station.
      (2) Pipe location is known
      (3) Hand digging to expose air to soil transitions to perform maintenance
      (4) Hand digging is limited to 24 inches in depth
   b. Performing close interval survey - ALL of the following criteria must be met:
      (1) Gas transmission facility in paved area
      (2) Drilling through asphalt or concrete/pavement. Drilling stops as soon as soil is encountered.
      (3) Use of an 18" drill bit or shorter (or depth control mechanism).
      (4) Operator will visually confirm when the drill bit has made contact with soil, cease the drilling, and only use hand-digging methods (i.e., probing) in the soil.

6.4 (continued)

c. Ensure locating instrument confirms there are no facilities in the pavement prior to beginning work.

d. Ensure field meet includes scope of project and identifies any anomalies. If the project scope changes or any additional anomalies are found, immediately contact the responsible standby personnel to determine whether or not a stand-by is required.

3. Perform the following when a standby is needed:

a. Inform excavator of requirement for a standby person to be on site when excavation will occur over identified areas.

b. Request 48-hour advance notification from excavator, when possible, for scheduling a standby person.

c. Document the following in USA ticket response screen:

(1) All actions taken

(2) All communications with excavator including:

- Name and phone number of excavator contact person
- Location of facility where standby is needed
- Reason why a standby person is needed (e.g., excavation will occur within 5 ft of a fiber optic facility and a 24" steel gas transmission facility)

4. Refer to TD-5811P-301 for actions to take while performing standby.

7 Record Retention

7.1 Retain records per the Record Retention Schedule.

END of Instructions

Responding to an Underground Service Alert (USA) Ticket

DEFINITIONS

Continual excavation: A location where excavation is part of the normal business activities of that location, including, but not limited to, agricultural operations and flood control facilities. A continual excavation ticket is valid for one year from the date of issuance.

Critical facilities: All gas transmission facilities (including those operating at less than 60 psig, such as large volume customers) and all electric facilities operating at or above 60 kilovolt (kV). The following facilities are also critical facilities:

- Distribution facilities operating at greater than 60 psig
- Distribution regulator stations
- Distribution regulator station supervisory control and data acquisition (SCADA) equipment, SCADA sense and data lines, and regulator control lines
- Electric distribution facilities which, if damaged, are likely to result in outages of long duration or outages to critical customers
- All fiber optic (FO) facilities

Damage: Includes breaks, leaks, nicks, dents, gouges, grooves, or other damage to underground lines, conduits, coatings, or cathodic protection. (See California Government Code [CGC] Section [§] 4216.4 [c].)

Excavation: Any operation in which earth, rock, or other material in the ground is moved, removed, or otherwise displaced by means of tools, equipment, or explosives in any of the following ways: blasting, boring, backfilling, removal of aboveground structures by either mechanical or explosive means, grading, trenching, digging, ditching, drilling, augering, tunneling, scraping, cable or pipe plowing and driving, or any other way.

Responding to an Underground Service Alert (USA) Ticket

Definitions (continued)

High-priority facilities: Any of the following facilities (see CGC §4216 [e]):

- High-pressure natural gas pipelines with normal operating pressures greater than 415 kilopascal (kPA) gauge (60 psig)
- Petroleum pipelines
- Pressurized sewage pipelines
- High-voltage electric supply lines, conductors, or cables that have a potential to ground of greater than or equal to 60 kV
- Hazardous materials pipelines that are potentially hazardous to workers or the public if damaged

Underground service alert (USA): Regional One-Call notification centers for the Company service territory. There are two centers serving the Company: Underground Service Alert of Central/Northern California and Nevada (USA North) and Underground Service Alert of Southern California (Dig Alert). For emergency tickets, USA North 811 Express OR Dig Alert Express may be used.

USA ticket: A document created when an excavator calls USA personnel to request underground facility locations before excavating.

Vacuum excavation: A means of soil extraction through vacuum using pressured water or air for breaking ground.

IMPLEMENTATION RESPONSIBILITIES

This is one of a group of new and revised locate and mark guidance documents being published along with the new *Locate and Mark Field Training Guide* developed by Academy, Gas Field Support, Locate and Mark, and other affected stakeholders.

Locate and Mark leadership will ensure that face-to-face and virtual learning sessions communicate these changes to the target audience, and that supervisors of affected work groups are provided training guides.

Gas Qualifications department will update affected qualification evaluations with the new document number and process changes.

Tailboard sign-off is required for all holders of OQ-0501 (PG&E personnel and contractors).

GOVERNING DOCUMENT

Utility Standard TD-4412S, “Preventing Damage to Underground Facilities”

Responding to an Underground Service Alert (USA) Ticket

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

California Government Code 4216

Code of Federal Regulations (CFR) Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Section (§) 192.703 (b) and (c), “General.”

REFERENCE DOCUMENTS

Developmental References:

Code of Safe Practices

Common Ground Alliance Best Practices

USA North’s *California Excavation Manual*

Supplemental References:

Form TD-4412P-05-F02, “Pre-Dig Verification Checklist”

Form TD-4414P-01-F01, “Job Site Safety Analysis (JSSA) for Tailboard Briefing”

GDS M-54.1, “Impact Bar Probe”

GDS M-60, “Approved Locate and Mark Instruments, Equipment, Accessories and Products”

GDS M-84, “Non-Contact Voltage Tester”

Utility Procedure TD-5811P-301, “Performing Standby”

TD-5811P-301, Attachment 1, “Handling Excavators Working Unsafely”

Utility Procedure TD-5811P-1100, “Locating Methods and Instruments”

Utility Procedure TD-5811P-1200, “Locating and Marking Subsurface (underground) Facilities”

Utility Standard TD-4016S, “Gas Operations Records and Information Management”

APPENDICES

NA

ATTACHMENTS

NA

Responding to an Underground Service Alert (USA) Ticket

DOCUMENT RECISION

The following Job Aids, Utility Bulletins, and Utility Procedures are being cancelled:

TD-5811P-101, “Preparing for Daily Work”

TD-5811P-101-JA01, “Standard Vehicle Checklist”

TD-5811P-101-JA02, “Using IRTHnet for Locating USA Tickets”

TD-5811P-101-JA03, “*Tech Down process: Printing MET Maps for Locate and Mark – Tablets Not Available”

TD-5811P-101-JA04, “*Tech Down process: Completing Tickets for Locate and Mark – Utilisphere Not Available”

TD-5811B-001, “Locate and Mark Tech Down Process”

TD-5811B-003, “Determining the Scope of a Locate”

TD-5811B-005, “Change to Critical Facility Definition”

TD-5811P-102, “Determining Scope of Locate”

TD-5811P-102-JA01, “Using Utilisphere on Tablet”

TD-5811P-103, “Identifying the Proper Location”

TD-5811P-103-JA01, “Troubleshooting Difficult-to-Locate”

TD-5811P-103-JA02, “Choosing Best Frequency”

TD-5811P-104, “Proper Markings”

TD-5811P-105, “Responding to a Ticket”

TD-5811P-105-JA01, “Choosing the Correct Utilisphere Response”

TD-5811P-105-JA02, “Submitting a Map Correction Form”

TD-5811P-105-JA03, “Corrective Work Form”

TD-5811P-105-JA04, “Identifying the Need for a Site Visit, Field Meet, and Standby”

TD-5811P-106, “Locating and Marking at Distribution Regulator Facilities”

Responding to an Underground Service Alert (USA) Ticket

DOCUMENT APPROVER

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REVISION NOTES

Where?	What Changed?
Revision 0c	
6.3	Added JSSA document number TD-4414P-01-F01.
6.4	Added note.
6.4.2	Clarified when standby is not required.
6.4.2	Added note and clarity on when standby exceptions.
Revision 0b (Publication Date: 10/10/2017; Effective Date: 12/15/2017	
Effective Date	Changed from 10/19/2017 to 12/15/2017.
Revision 0a (Publication Date: 08/14/2017; Effective Date: 10/19/2017	
6.4.1, first bullet	Added reference to exception in 6.4.2
6.4.2	Added new 6.4.2 to describe limited standby exception for critical transmission stations for exposing air-to-soil transitions.
Revision 0 (Publication Date: 07/19/2017; Effective Date: 10/19/2017)	
Entire procedure	This is a new document that incorporates many former TD-5811 procedures into one document, as indicated in the Document Recision section. The major process changes are: • Added steps to meet new code requirements (CGC 4216) for locating and marking subsurface Company facility installations – marking abandoned facilities, new time frames for ticket responses (48 hours to 2 days not including the day it is called in); acceptable delineations. • Identified underground service alert (USA) process changes; Dig Alert (formerly USA South) and 811 Express (currently USA North). • Updated internal requirements for excavation to align with Utility Procedure TD-4412P-05, “Excavation Procedures for Damage Prevention.” • Added code requirements for field meets and standbys, including documentation for excavation performed by PG&E, for PG&E or 3rd party. • Updated internal critical facility definition.

PART 1: OVERVIEW

a) Best Practice: 26 **b) Status:** Complete

Dig-Ins / 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.

PART 2: BEST PRACTICE DETAILS

a) Historic work:

PG&E has created the "Dig-in Reduction Team," (DiRT) to investigate and educate excavators who damage PG&E's underground facilities. The team has a process to identify and interact with contractors who are responsible for multiple dig-ins during a 12-month period. The DiRT team provides safe digging classes free of charge, meets with company leadership to establish ongoing relationships, documents the damages for billing purposes, and recommends referral to the Contractor State License Board.

b) Alternative Proposal to BP or exemption?

None.

c) Proposed Plan:

PG&E plans to utilize its existing process as mentioned in question a) above as it adheres with the BP.

d) Overlap with other regulations? What portion of the BP is incremental beyond those regulations?

No other regulations overlap.

e) What technology is required to implement the best practice and why?

No technology is required.

f) Will work require additional personnel and/or contract support? If so, please provide details.

No additional resources are required.

g) What changes to existing operations are required? How will those changes be implemented?

No changes to existing operations are required.

h) What are the new procedures to develop or existing procedures to modify? Please provide details.

No new procedures need to be developed.

i) Timeline for implementation (Milestones):

Compliance with this BP is complete.

j) Identify the range of factors or considerations used to determine cost-effectiveness of this measure, when costs estimates have been determined:

No costs are associated with this BP.

k) Identify any cost benefits from this BP, when cost estimates are known:
Cost benefits are unknown, however, the investigations the DiRT team provide have substantially increased collection rates from billing dig-in offenders. The number of contractors with 3 dig-ins or more (3rd party at fault) has been decreasing from 61 in 2015 to 55 in 2017.

l) Do any incremental costs, if known, or benefits overlap with other BPs? If so, to which BP do they overlap, what are they, and how do they overlap?
See question j) above.

m) Anticipated Emissions Reductions from this BP:
Benefits from this BP, BP 24, and BP 25 will collectively impact the emissions from distribution and transmission dig-ins which are reported under the annual leak report, pursuant to the Leak Abatement OIR. The progress over time can be tracked in the report.

2015 Baseline Emissions affected, where known:
In 2015, emission from distribution dig-ins is 127 MMscf while emission from transmission dig-ins is 81 MMscf. The total is 208 MMscf.

n) Calculation Methodology:
See section m) above.

o) Additional Comments:
None.

p) Overlap with Safety:
The guidance document(s) and programs implementing this best practice will maintain PG&E's existing safety standards associated with performing work that could result, in a planned or unplanned manner, in the evacuation of natural gas.

SUPPLEMENTAL INFORMATION

a) Technology:
None.

b) Changes to Operations:
None.

c) Research or Studies:
None.

d) Other:
None.