
Pacific Gas and Electric Company®

PUBLIC VERSION

# 2019 GAS SAFETY PLAN

MARCH 15, 2019

Pacific Gas and Electric Company®

March 15, 2019

Dear Reader,

It is our fundamental responsibility to design, build, maintain, and operate our gas systems to keep customers and communities safe. The 2019 Gas Safety Plan ("Plan")[1] provides a high-level view of both the work we accomplished in 2018, and our plan moving forward to achieve our goals. The Plan continues to build upon the framework PG&E set forth in 2016 and strives to present important Gas Operations information in a manner that is accessible and clear to a broad audience.

PG&E's 2019 Gas Safety Plan includes several aspects that are new to the 2019 Plan. First, the 2019 Plan includes a section describing PG&E's newly developed data asset family. This asset family was created to strategize the management of data, streamline data collection efforts, and develop clear accountability for data. Second, PG&E includes in the 2019 Plan a discussion of metrics related to PG&E's Serious Incidents and Fatalities (SIF) program in Gas. This program focuses efforts on addressing tasks and incidents that have the potential to cause a serious injury or fatality. Incidents that have potential for serious injury or fatality receive a deeper evaluation and increased management oversight to prevent repeat occurrences. Finally, the 2019 Plan includes expanded discussion of PG&E's work to strengthen employee engagement, including multiple efforts to encourage supervisors and employees at all levels to speak up and ensure safety is at the forefront in the workplace.

While we have made progress in key safety areas, we realize there is more to do to demonstrate our commitment and progress towards Gas Safety Excellence. Even in the light of the current environment facing PG&E, the communities we serve, and the public, we remain focused and dedicated to becoming the safest, most reliable gas utility in the United States.

Jesus Soto, Jr.
Senior Vice President, Gas Operations
Pacific Gas and Electric Company

[1] PG&E submits this plan in accordance with General Order 112-F Section 123.2(k), and Public Utilities Code §§961 and 963.

# PACIFIC GAS AND ELECTRIC COMPANY
# GAS SAFETY PLAN

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## I. INTRODUCTION

Pacific Gas and Electric Company (PG&E or the Company or the Utility) works every day to safely transport natural gas under pressure through approximately 6,600 miles of transmission, 42,700 miles of gas distribution pipelines, and 4.3 million meters. The PG&E natural gas system serves millions of Californians from Eureka in the North to Bakersfield in the South, and from the Pacific Ocean in the west to the Sierra Nevada in the east. PG&E's employees work around the clock, 365 days a year to keep the public, customers, contractors, and employees safe. Even in the light of the current climate facing PG&E, our mission remains to safely and reliably deliver affordable and clean energy to our customers and communities every single day, while building the energy network of tomorrow.

While there is more work to do to achieve PG&E's mission, PG&E's Gas Safety Plan provides a view into the safety activities PG&E pursues every day and highlights the specific safety work in 2018. Figure 1 provides a summary of PG&E's performance in key areas.

# Gas Operations "See Our Progress"

Gas Operations progress since 2010 demonstrate our commitment to becoming the safest, most reliable gas company in the country.

| | 2010 | 2018 |
|---|---|---|
| **GAS ODOR RESPONSE TIMES** | | |
| Average response time in minutes | 33.3 | 20.6 |
| Percent response within 60 minutes | 94.4% | 99.6% |
| **SCADA VISIBILITY AND CONTROL POINTS** | | |
| Transmission pressures and flows | 1,300 | 2,666 |
| Transmission Control Points | 870 | 1,783 |
| Distribution pressures and flows | 290 | 4,114 |
| **LEAK BACKLOG** | | |
| Open Grade 2 and 2+ leak indications | 12,203 | 239 |
| **DIG-IN REDUCTION** | | |
| Excavation damage/1,000 excavation tickets | 3.5 | 1.61 |

| | 2010 | 2011–18 |
|---|---|---|
| **GAS TRANSMISSION** | | |
| Miles of pipeline replaced | 9 | >265 |
| Miles of pipeline strength tested | 0 | >1,380 |
| Miles of pipeline made piggable | 130 | >1,071 |
| Automated valves installed | 0 | 337 |
| **GAS DISTRIBUTION** | | |
| Miles of main replaced[1] | 27 | >737 |

**SINCE 2011 PG&E HAS ALSO**

Completed GPS survey for 100% of the accessible transmission pipeline system using highly precise mapping tools

Opened a state-of-the-art Gas Control Center in San Ramon, California

Opened a world-class Gas Safety Academy located in Winters, California

Opened the Center for Gas Safety and Innovation located in Dublin, California

**Certifications received for gas operations:**

In 2014, PG&E became one of the first utilities ever to earn two of the highest internationally recognized asset management certifications—the International Organization for Standardization (ISO) 55001 and Publicly Available Specification (PAS) 55-1.

- Gas Operations was recertified for both of these standards in 2017 and, in 2018, Lloyd's confirmed PG&E's continued certification to the PAS 55/ISO 55001 standards for best-in-class asset management.

In 2015, PG&E became the first company in the U.S. to receive compliance for the industry standard on pipeline safety management system, the American Petroleum Institute Recommended Practice (API RP) 1173.

- In November 2018, PG&E was successfully recertified as compliant with API 1173.

In 2016, PG&E became the first utility to receive the chemical industry's RC14001® management system standard. RC 14001 was developed as a standard issued through the American Chemistry Council for process safety; community communications.

[1]In 2014 all known remaining cast-iron pipe was decommissioned.



**Figure 1 – Key Gas Performance Metrics**

## 1. Structure of the Gas Safety Plan

The 2019 Gas Safety Plan (Plan) reports on the progress PG&E has made on its goal to become the safest, most reliable gas company in the United States (U.S.), and details the work performed in 2018. The Plan reiterates PG&E's commitment, mission, and vision to safely and reliably deliver affordable and clean energy to our customers and communities. In alignment with California's regulatory framework,[1] this Plan explains how PG&E puts the safety of the public, customers, employees and contractors first, and how the Company has made safety investments in processes and infrastructure that are consistent with best practices in the gas industry.

The following sections of the Plan provide more information on how PG&E is achieving Gas Safety Excellence, and include updates on the Company's safety goals and commitments to public, customer, employee, and contractor safety.

- **Gas Safety Excellence Management System:** A safety management system provides the framework and structure to drive operational excellence to create industry-leading safety and reliability performance across the organization. It is a systematic process to protect, manage, and improve performance in dimensions of safety that are critical to reducing risks. This section describes PG&E Gas Operations' safety management system that permeates every aspect of gas operations known as the "Gas Safety Excellence Management System."
- **Safety Culture, Process Safety, and Asset Management:** Safety culture, process safety, and asset management together form the foundation of Gas Safety Excellence. These sections review how PG&E manages risk—both the inherent risk of the assets *and* the risk of working on those assets safely. This section describes how the Company identifies risk, prioritizes risks and then works to mitigate them, highlighting the three major categories of gas system risk the Company manages: loss of containment, loss of gas supply, and inadequate emergency response.
- **Workforce Safety and Compliance Framework:** These sections review how PG&E qualifies, trains, and engages the workforce to mitigate risk by working on assets safely and performing work right the first time. These sections include information about PG&E's workforce training and qualifications programs, and how PG&E achieves compliance.
- **Continuous Improvement:** This section presents PG&E's efforts to continuously improve processes and procedures.

## 2. The Pursuit of Gas Safety Excellence

Gas Safety Excellence is demonstrated by:

- Putting ***SAFETY*** and people at the heart of everything
- Investing in the ***RELIABILITY*** and integrity of PG&E's gas system
- Continuously improving the effectiveness and ***AFFORDABILITY*** of PG&E's processes
- Supporting emissions reduction and working to advance PG&E's comprehensive ***CLEAN*** energy goals


**Figure 2 – PG&E Gas Safety Excellence Management System**

The Gas Safety Excellence Management System is PG&E Gas Operations' safety management system developed to achieve the vision of becoming the safest, most reliable, affordable, and clean gas utility in the nation. This safety management system provides the structure to systematically manage and maintain operational excellence in asset management, safety culture, and process safety, with a commitment to continuous improvement and in compliance with best-in-class industry standards. The Gas Safety Excellence Management System consists of the following sixteen elements that focus on supporting performance management to achieve our goals:

1. Leadership Commitment, Accountability and Employee Participation
2. Asset Management and Life Cycle Planning
3. Risk Assessment and Management
4. Incident Investigation and Corrective Action(s)
5. Compliance with Legal, Regulatory and other Operational Requirements
6. Operational Planning and Control(s)
7. Communication and Stakeholder Engagement
8. Information, Documentation and Records Management
9. Contractor Management and Third Party Services
10. Training, Competency and Awareness
11. Management of Change
12. Monitoring and Measurement
13. Emergency Preparedness and Response
14. Auditing
15. Quality Management and Continuous Improvement
16. Management Review

PG&E's Gas Safety Excellence Management System strives to enable employees to do their work right the first time to deliver high-value, quality services.

## 3. PG&E'S GOALS

Gas Operations' annual goals are developed through the "Line of Sight" process. This process incorporates Executive Guidance and key themes and strategies developed through PG&E's annual, multi-year strategic and work plan development processes: Session D, Session 1 and Session 2.[2] "Line of Sight" goals in 2018 aligned business strategy with six key themes: Safe, Reliable, Affordable, Customer, People, and Compliance. This planning process results in strategic goals to drive action throughout the business. Related goals and metrics cascade throughout the organization to provide each employee a line of sight to how their actions support PG&E's vision. These items are discussed in more detail throughout this update.

### a) PUBLIC SAFETY

In 2018, PG&E had success in three primary safety areas: In-Line Inspections (ILI), Emergency Response Time, and Third-Party Dig-Ins.

- **In-Line Inspection:** In 2018, PG&E increased piggability to roughly 32 percent of the approximately 6,600 miles of the Gas Transmission system and used ILI tools to inspect over 297 miles of transmission pipeline. PG&E plans to upgrade approximately two-thirds of its transmission system (about 4,100 miles) to accept ILI tools by the end of 2026.
- **Emergency Response Time:** PG&E exceeded its target and achieved first quartile performance with a 20.6-minute average response time to gas odor calls, responding to 140,740 gas odor calls in 2018.
- **Third Party Dig-In:** In 2018, PG&E experienced 1.61 dig-ins per 1,000 Underground Service Alert (USA) tickets, out-performing its 2018 target of 1.84 dig-ins per 1,000 USA tickets.

### b) WORKFORCE SAFETY

PG&E's goal is to provide a safe and secure workplace where each employee is appropriately trained and equipped to complete their work right the first time. PG&E's goal is zero safety incidents.

Toward that end, PG&E designed the One PG&E Occupational Health and Safety Plan ("One PG&E Health & Safety Plan"), in part, using an analysis of the leading drivers of injury to determine plan elements. The One PG&E Health & Safety Plan is developed by Corporate Safety and Health with input from all lines of business, and is a multi-year plan focused on areas where injuries and incidents are occurring. Each line of business (LOB) adopts the initiatives and implements the practices contained therein throughout the year. The 2018 One PG&E Health & Safety Plan focused on eight initiatives

relating to Musculoskeletal Disorders, Motor Vehicle Safety, Health and Wellness, Safety Management Systems, Serious Injury or Fatality (SIF), Contractor Safety, Injury Management, and Supervisor Leadership Development.

In 2018, Gas Operations employees were involved in 29 Lost Time Injuries, a 22 percent decrease from 2017. In 2018, the California Occupational Safety and Health Administration (OSHA) recordable rate for Lost Time Injuries decreased by 8.9 percent. This may result from PG&E's increased emphasis on the twenty-four hour, seven days a week Nurse Care Line and early reporting. In 2018, 77.6 percent of employees who called the Nurse Care Line reported discomfort or an injury within 24 hours, exceeding the target of 75.6 percent. This renewed emphasis on early intervention has had a positive effect on workforce injuries. Based on the review of our data, PG&E believes that speaking to a healthcare professional about an injury or illness within 24 hours contributes greatly to the reduced severity and recovery time of an injury or illness. Through consistent application of reporting and preventative efforts, the serious lost time injuries have begun to follow the OSHA recordable curve and shows improvement.

In 2018, Gas Operations had six safety incidents that had the potential to cause a SIF. A SIF committee comprising department representatives evaluates the severity of the incident. Once an incident is determined to be a SIF, a causal evaluation team is assembled to investigate the facts of the incident, determine the contributing factors, and identify the causal factors. The team also develops comprehensive corrective actions to minimize and/or prevent reoccurrence. Upon completion of the internal investigation, a written report is presented to the Corrective Action Review Board to evaluate and accept the corrective actions. A third party then evaluates and scores the quality of the corrective actions. PG&E added additional evaluation measures, such as Timely Corrective Action Completion and Quality of Corrective Actions, to focus on the quality and timely closure of corrective actions from SIF investigations. In 2018, Gas Operations completed 95 percent of the corrective actions in a timely manner.

Another area of focus continues to be Motor Vehicle Safety. In 2018, there were nine Serious Preventable Motor Vehicle Incidents (SPMVI), a 36 percent decrease from 2017. In 2017, the Company installed an in-cab coaching technology to over 2,600 gas vehicles and developed a metric to score employees' driving behaviors. The technology tracks quick acceleration and hard braking which is then applied per 1,000 miles driven. This ratio yields a Safe Driving Rate in which a lower ratio is preferred. In 2017, Gas Operations scored a Safe Driving Rate of 9.4 and

**Figure 3 – Examples of PG&E Gas Motor Vehicles**

established a 2018 target of 8.6. In 2018, Gas Operations finished with a Safe Driving Rate of 6.2, a 34 percent reduction from the previous year. The Safe Driving Rate for vehicles with the in-cab technology are showing positive results as indicated by the decrease in the number of SPMVIs. The technology alerts drivers when their vehicle accelerates too fast or brakes too hard. These are both leading indicators to incidents that have the potential to cause extensive damage or a SPMVI.

While we reduced our SPMVI count, we had a 4 percent increase of Preventable Motor Vehicle Incidents (PMVI). In 2018, there were 147 PMVIs compared to 142 in 2017. PMVIs are incidents that do not cause extensive damage, such as a backing incident in a parking lot.

As the Company continues to improve its motor vehicle safety program, plans to conduct more driver observations, evaluate backing sensor technology, enhance driver safety training, and promote awareness campaigns, PG&E is optimistic that it will continue to reduce OSHA recordable injuries and motor vehicle incidents.

### 4. Rewarding Safety Excellence

PG&E's performance goals reinforce expectations regarding management decisions and allocation of resources.

PG&E awards employees and contractors for their safety excellence by encouraging safe behavior and practices. These awards include:

- Eagle Eye Award – Recipients of this award can include those who submit Corrective Action Program (CAP) items that can decrease the risk of fatalities or injuries, damage to assets, reliability issues, and environmental impact. Any employee can submit an Eagle Eye nomination.
- Caught Being Safe – Under this program, rewards and recognition are provided for employees who demonstrate safe behavior, speak up and take action to promote a positive safety culture, and/or support the One PG&E Health & Safety Plan. As a token of appreciation, the employees who nominate them are also eligible to receive rewards and recognition.
- Process Safety Ambassador Award – This award recognizes teams and individuals for going above and beyond in applying the keys to Process Safety to their work, such as having a questioning attitude, taking time to evaluate the hazards prior to starting a task, and reporting a CAP.

## II. Safety Culture

PG&E's commitment to strengthening our safety culture and performance is reinforced in the Company's Mission, Vision, and Culture. Figure 4 illustrates PG&E's mission, vision and culture statements that are the foundation of our decision-making process.

The imperative to put safety first drives everything we do and creates an understanding for our employees that their actions must reflect that priority. In 2015, PG&E launched a series of workshops to enhance the safety skills of our leaders and promote a speak-up, listen up, and follow up culture. As of mid-December 2018, approximately 99 percent of our leaders involved in operations field work—from crew leads to senior leadership—have completed the workshops [see Section V.2 *Workforce Safety Projects*]. Additional companywide efforts, such as the introduction of Operational Learning concepts, the creation of Learning Teams, the Reach Every Employee (REE) initiative, the redefined Contractor Safety Program, and the enterprise-wide CAP reinforce and enable our employees' and contractors' commitment to improve safety culture and performance.

We measure our safety culture progress in a variety of ways, as follows:

- Continued independent third-party verification of our Company's systems and processes, including the American Petroleum Institute's (API) Recommended Practice (RP) 1173, Pipeline Safety Management System Requirements.[3] PG&E initially earned a certificate of compliance with the requirements of API RP 1173 from an independent third-party auditor in November 2015. In November 2018, PG&E earned a renewal of this certificate.
- The CAP has been implemented across the entire Company. One CAP metric used as an indicator of safety culture health is the number of anonymous submittals. In 2018, the companywide anonymous submission rate was 2.5 percent of all issues submitted to CAP. Of the issues submitted to CAP that were related to Gas Operations, 2.1 percent were anonymous. CAP's low anonymous submission rate is an indication that employees are willing to speak up and be recognized for their concerns and ideas [see Section II.1.a *Corrective Action Program*].


**Figure 4 – PG&E's Mission, Vision, and Culture Statements**

- In 2018, we deployed our All Employee Survey to gain valuable employee feedback and attitudes on a wide variety of topics such as Safety, PG&E's Speak-Up Culture, Compliance & Ethics, Leadership Communications and Workforce Empowerment. With this feedback in mind, leaders look for areas of concern and opportunities for improvement.

## 1. EMPLOYEE ENGAGEMENT

In 2018, PG&E created new processes to enhance employee engagement. These initiatives included: Lean Management, Operational Learning, Reach Every Employee, and Organizational Health Index.

**Lean Management.** In 2018, Gas Operations implemented meetings called "huddles" throughout the LOB. Teams schedule huddles on a set cadence to discuss issues and opportunities and to share best practices. Huddles are also used to set expectations for the day and discuss work execution from the previous day [see *Section VII.2. Lean Capability Center*]. PG&E has created a line of sight between organizational objectives and the work performed. By aligning corporate strategies and work plans, PG&E supports a fluid bottom-up flow of ideas and feedback for continuous improvement.

To show the focus on engagement, PG&E leadership created specific engagement activities around key aspects of work, leveraging employee feedback, and facilitating the development of initiatives based on the feedback. For example, leaders identified top business priorities for each function and developed Lean Deployment Plans to target these areas. Additionally, employees have designated time set aside for Problem Solving sessions where roadblocks are identified and employees are given the opportunity to help develop a solution. "Lean Bootcamp" was launched for core tools targeting Supervisors, Managers, and Superintendents with 51 percent currently trained.

Lean also encourages leaders within Gas Operations to spend more time engaging with their employees directly. Leaders regularly visit locations where the work is occurring to meet employees, hear firsthand their thoughts on what is working well and where improvements are needed, and to observe the work being performed to see for themselves what opportunities for improvement exist.

**Operational Learning.** In addition to Lean Management, in 2018, the Corporate Safety and Health organization and Gas Safety & Health Department introduced key concepts and tools related to Operational Learning to many of the leaders and employees in Gas Operations. Operational Learning is a process that focuses on understanding the difference between how work is planned and how work is actually done. Operational Learning is part of PG&E's Five-Year Executive Guidance and is a major initiative under the Safety Leadership Focus Area in the One PG&E Health & Safety Plan.

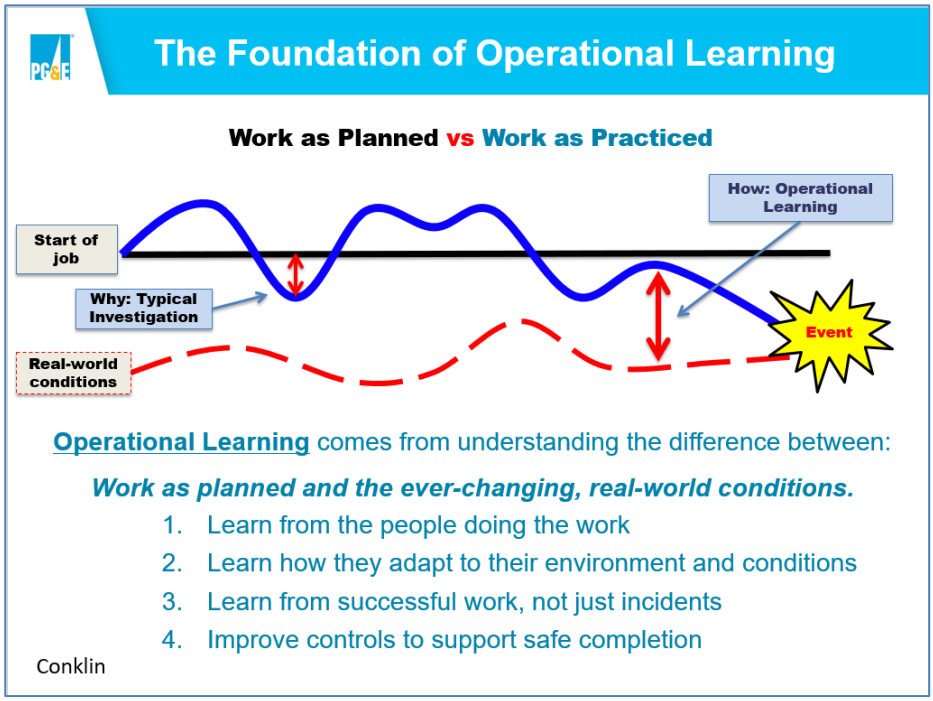



**Figure 5 – Occupational Learning Process From Todd Conklin, Ph.D.**

The way to understand how work is done and understand the obstacles employees face to make systemic change, is to engage in open and unfiltered conversations with employees. These conversations provide the opportunity to those who do the work to describe how failure and success really occur in the field. By learning this information, leaders can better understand how peoples' actions and assessments made sense at the time, given the circumstances that surrounded them. Often from these conversations, leaders realize that human error can be a symptom of trouble deeper inside a system. Identifying and correcting these systemic issues helps assure employees that when they make an error, they can "fail safely" such that injury can be avoided. The important cultural shift that comes from incorporating Operational Learning concepts is to move from a culture of blame to a culture of learning.

In 2018, avenues by which Gas Operations leaders and employees received this information are:

- 2018 Safety Summits, organized by each department for their respective employees, which contained Operational Learning concepts within the Safety Leadership Development Initiative segment of the One PG&E Safety & Health Plan;
- 2018 Gas Operations Line of Sight Extended Leadership Team Meeting; and
- 2017-2018: Several department-specific meetings and workshops where guest speakers, such as Todd Conklin, Ph.D., an internationally recognized expert in Organizational Culture and Human Performance, delivered material related to Operational Learning.

Figure 6 – A Team That Appreciated the Reach Every Employee initiative

Learning Teams are another type of activity that supports Operational Learning concepts, as well as PG&E's Speak Up, Listen Up, and Follow Up culture. Corporate Safety and Health established Learning Teams as a result of benchmarking safety best practices across several different industries. Learning Teams are formed by gathering a group of front-line employees, led by a trained facilitator, to discuss how work is done and where gaps exist. As a group, the Learning Team identifies and understands strengths in a system, as well as opportunities for improvement. Gas Operations began integrating Learning Teams throughout the LOB. In 2017 and 2018, Gas Operations employees participated in three learning teams, focused on Gas CAP, Gas Pipeline Operations and Maintenance for compressor stations, and an enterprise-wide team focused on prevention of motor vehicle incidents.

**Reach Every Employee (REE).** Starting in January 2018, as part of an enterprise-wide effort to engage all employees in PG&E's Speak-Up Culture, Gas Operations began the REE initiative, a process and framework for all leaders to discuss safety with each direct report, either one-on-one, or in small groups. REE was designed to create opportunities for regular, meaningful conversations between supervisors and their employees, across all levels of the Company, to foster a safe environment for employees to speak up about safety concerns, potential barriers that exist to working safely, and reinforce that "getting the job done" should never be achieved at the cost of safety. More broadly, REE helps create a safe environment for speaking up at PG&E by reinforcing the concept that leaders should actively listen to employee concerns, support and help employees take actions, and be an advocate for employees when they are vulnerable. Conversations based on the REE model are expected to continue every year.

One example of REE's effectiveness in encouraging employees to speak up, includes a Gas superintendent who discovered that some of his team members who were normally reserved in team meetings became relaxed and opened up during one-on-one conversations. During those conversations, individuals provided input on topics such as workload, huddles, and project designs. The team members appreciated the one-on-one conversations with their superintendent because it helped them communicate their concerns.

**Organizational Health Index.** One of the ways that PG&E measures employee engagement is through the Organizational Health Index (OHI). OHI is an annual employee survey that collects feedback regarding management behaviors and organizational outcomes, including how we align on a shared

direction, execute accordingly, and learn and innovate along the way. The 2018 survey results showed an overall two-point increase compared to 2017, and highlighted strengths including a strong safety culture and improved leadership practices. That said, the overall health score was still considered third quartile,[4] so detailed action plans were created to support our aspirations of achieving top quartile health by 2021. These action plans focused on improving key management practices through the use of Lean tools and behaviors including continuous improvement, performance transparency, meaningful rewards, and engaging employees closest to the work to solve problems and improve processes.

## a) Corrective Action Program

Gas Operations launched the Gas CAP in 2013 to offer employees a method to identify and report issues, or ideas, related to gas assets and processes. Submissions include employee concerns, suggestions, operational events, internal or external audit findings, data requests, or issues with facilities, tools, records, training, and safety.

The CAP process employs a standardized approach (Figure 7), including a CAP Review Team, composed of Subject Matter Experts (SME) from various Gas departments, that meets regularly to review CAP issues submitted the previous business day. The team's function is to categorize each issue, assess it for risk, and assign it to an owner. The role of the issue owner is to investigate and identify the causes underlying the issue and to address them appropriately by implementing corrective actions to mitigate risks and/or prevent recurrence. Initiators receive an email when the item they submitted is assigned and again when it is closed. This affords the initiator the opportunity to learn how the issue was resolved, and to provide feedback on their satisfaction with the results. The CAP provides real-time data and ensures transparency and accountability. The system is designed to provide trending capabilities and a continuous improvement loop to capture lessons learned and to improve the safety and reliability of PG&E's operations.

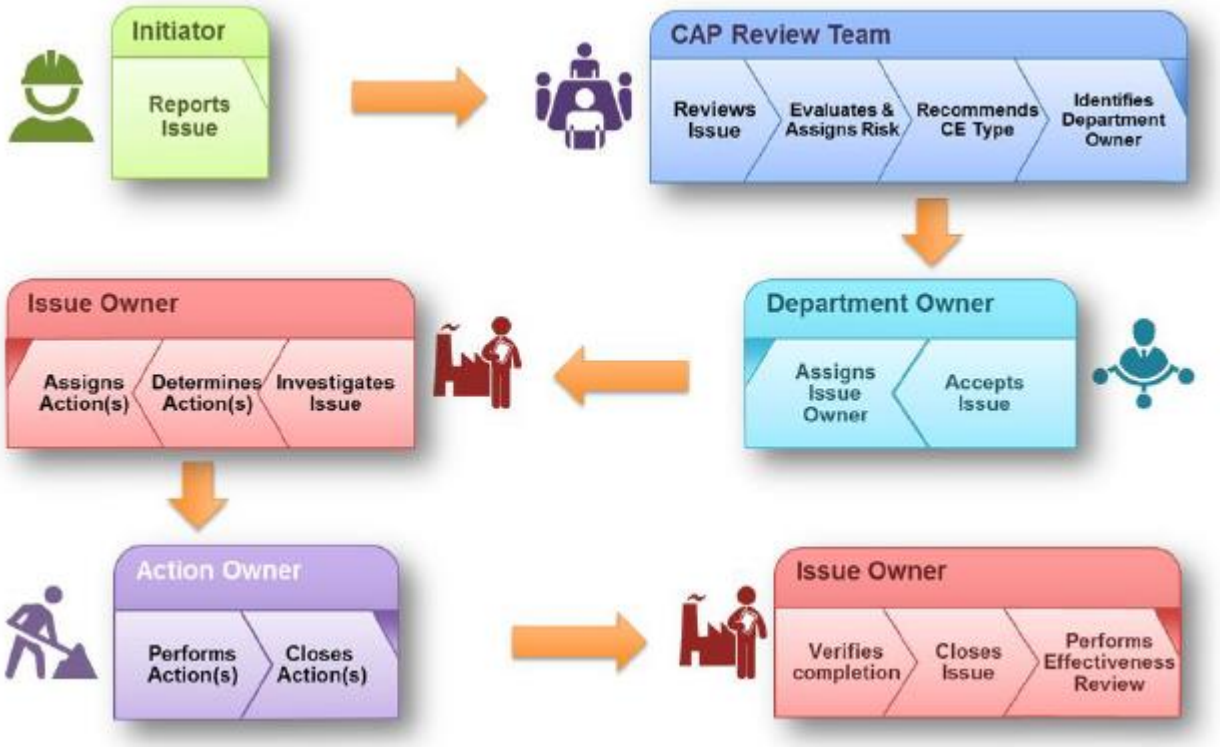



**Figure 7 – CAP Process**

PG&E's 2018 goal was to engage at least 33 percent of the Gas Operations workforce to use CAP, and it slightly exceeded that goal. In 2018, Gas Operations employees submitted 15,378 issues—averaging just over 1,280 per month—and closed 13,882 issues.

To ensure transparency, leaders receive an Executive CAP Dashboard Report (Figure 8) each week that details how their organization is performing on their CAP items. Key performance indicators reported in 2018[5] include:

- Percent of Unique Initiators – This is the number of employee submissions divided by the total count of employees. The 2018 goal was greater than or equal to 33 percent of unique initiators.
- Average closure satisfaction (1-5 scale) is the sum of survey scores divided by the number of survey submissions. The 2018 goal was an average closure satisfaction greater than or equal to 3.5, where 1 is "very satisfied" and 5 is "did not meet expectations."
- Quality closure (percent) is the number of CAP issues passing quality review divided by the number of CAP issues reviewed. The 2018 goal for quality closure was greater than or equal to 92 percent.
- Average Age of Open High-Risk Issues (days) – This is the number of days high-risk issues are open divided by the number of open high-risk issues. The 2018 goal for average age of open high-risk issues was 230 days.

- Average Age of Open Medium-Risk Issues (days) – This is the number of days medium-risk issues are open/number of open medium-risk issues. The 2018 goal for average age of open medium-risk issues was less than or equal to 230 days.[6]

Figure 8 shows how Gas Operations performed against the above mentioned key performance indicators.


**Figure 8 – CAP Metrics**

In 2017, the CAP Department routinely conducted monthly quality closure reviews on all high and medium-risk issues (as determined by a CAP risk matrix), as well as a sampling of low-risk issues. An example of a high-risk issue is an employee fatality or serious injury. An example of a medium-risk issue is limited loss of service. An example of a low-risk issue is limited or no damage to assets. In 2018, the CAP Department began reviewing all closed issues, regardless of risk level. These closure reviews are performed to confirm that issues are adequately addressed and properly documented.

In 2018, the CAP Department conducted problem solving sessions with members of the CAP Review Team to further streamline its processes. All suggested improvements were implemented in August 2018, including those such as meeting frequency, member engagement and composition, and roles and responsibilities.

The Gas CAP process continues to mature and serves an important role in Gas Operations to identify and mitigate operational and safety issues and implement process improvements.

## b) Compliance and Ethics Helpline

PG&E's Compliance and Ethics (C&E) Helpline is a toll-free telephone number available to employees, contractors, consultants, suppliers, and customers 24 hours a day, 7 days a week. The C&E Helpline, managed for PG&E by NAVEX Global, enables callers to request guidance about our Code of Conduct or make a good-faith report of violations of our Code of Conduct, fraud, accounting issues, or illegal activity. Callers may remain anonymous. In addition to calling, other methods to contact C&E to

request guidance or submit a report include making a web-based report (also managed for PG&E by NAVEX Global) or contacting C&E directly.

Concerns raised with C&E through its Helpline or any other method are documented and tracked to closure. PG&E has a strict policy against retaliation against anyone who speaks up or is involved in an investigation. The C&E Helpline is part of PG&E's commitment to fostering a workplace where everyone feels safe to ask for guidance, share ideas or raise concerns—and one where everyone is confident that those concerns will be heard and taken seriously.

In addition to the C&E Helpline, PG&E's Federal Court-Appointed Monitor[7] has a dedicated hotline, email, and website that employees and the public can call with concerns. Although the hotline is not equipped to handle safety emergencies or other issues requiring immediate attention, it is another resource for employees to raise issues or concerns.

### c) Material Problem Reporting

PG&E also encourages employees to report and act on problems with any materials, tools, gas/electric/other equipment or infrastructure through the Material Problem Reporting (MPR) system. PG&E leverages the CAP reporting process to route material related problems to the MPR system. The MPR process is cross-functional and relies on employees at all levels of the business to identify potential safety issues stemming from material problems.

MPRs can be identified from two different sources:

1) A material arrives at PG&E's facilities; the PG&E team may identify "Incoming MPRs."
2) As work is performed with materials, personnel may identify "Field MPRs."

Incoming MPRs that are quality tested and found to fail at receipt prompt the creation of a Supplier Corrective Action Request (SCAR), requiring the supplier to resolve the issue. The SCAR process and system is managed by Supplier Quality Assurance (SQA) to ensure proper corrective actions are implemented. In 2018, this process had an average cycle time of 32 days, with a target of 20 days. The target for this process in 2019 is 20 days.

Field MPRs tend to be more complex, and as a result, may require more time to resolve. They require collecting the part from the field, shipping it to engineering, performing an investigation and interviews on method of installation, and material testing in a test lab to validate the method of failure. After the conditions and method of failure are determined, the material may be sent back to the manufacturer if it is proven to be defective. In 2018, Field MPR resolution had a 133-day average cycle as compared to its target of 70 days. The target for this process in 2019 is 70 days.

## 2. PG&E Corporate and Gas Safety Committees

PG&E's safety governance structure drives a consistent safety culture and aligns to PG&E's safety strategy and results. Table 1 describes PG&E's Corporate and Gas Operations safety committees. The monthly Gas Safety Council has standing agenda items for the Enterprise Safety Committee and Grassroots Teams. Gas senior leadership then communicates the information from those meetings to the Gas Operations Safety Council and the Grassroots Safety Team. This allows information to align and flow between the enterprise and Gas Operations.

| Table 1 – Safety Committees | |
|---|---|
| **Board of Directors Safety and Nuclear Oversight Committee** | Oversees matters relating to safety, operational performance and compliance. Conducts an annual evaluation of PG&E's performance in accordance with its Corporate Governance Guidelines. |
| **Enterprise Safety Committee** | Provides overall governance of safety; guides the enterprise safety strategy and philosophy; and drives continuous improvement of public, employee, and contractor safety performance. |
| **Gas Operations Safety Council** | Sponsors initiatives to improve LOB safety. Monitors Line of Business safety performance and initiatives so that safety initiatives adequately address risks. |
| **Gas Operations Grassroots Safety Teams** | Employee-led efforts to identify opportunities to improve safety, define and validate possible solutions, and implement and promote safety initiatives. |

See Attachments 1 and 2 for the charters for the Board of Directors Safety and Nuclear Oversight Committee and the Enterprise Safety Committee.[8]

# III. Process Safety

Process Safety Management[9] focuses on preventing low frequency, high consequence incidents, and mitigating the consequences from these incidents. The Process Safety Management System is used for engineering new facilities, modifying existing facilities, maintaining equipment, and ensuring safe operation.

The Process Safety Management System contains four foundational blocks (Figure 9): Commit to Process Safety, Understand Hazards and Risk, Manage Risk, and Learn from Experience. PG&E is improving process safety performance by strengthening performance in each of these areas.

When process safety performance gaps are identified, plans are developed and implemented to close them. A follow-up assessment is conducted to ensure progress remains on track and to verify performance improvement.


**Figure 9 – The PG&E Process Safety Management System**

Process Safety Highlights from 2018 include:

**Commit to Process Safety.** Guided by the elements set by the Center for Chemical Process Safety (CCPS), PG&E's commitment to implement process safety aligns with API RP 754 *Process Safety Performance Indicators for the Refining and Petrochemical Industries*.[10] Process Safety and Gas Safety Excellence teams used a risk-sorting criteria to track and trend process safety leading and lagging indicators. This helps identify emerging issues before incidents occur. The Process Safety team performed field location visits to engage the workforce in improving the Process Safety Management System.

**Understand Hazards and Risk.** Process Safety Management is a key component in reducing PG&E's Operational Risk Exposure. In 2018, PG&E used process safety principles in its large overpressure (OP) event reduction initiative [see Section IV.5.m. *Mitigating the Risk of Loss of Containment: Overpressure Elimination Initiative*]. In addition, the team took the lead role in investigating large OP events. The team also continued to focus on maturing design risk assessments and simplifying project design-phase Process Hazard Analysis (PHA) activities and checklists. Finally, in 2018, the team drove increased consistency in risk estimation by aligning the risk matrices among groups (i.e., Gas CAP, Enterprise CAP, and Process Safety).

**Manage Risk.** Process Safety efforts support risk mitigation. In 2018, risk mitigation continued through management of change (MOC) process improvements at manned Compression and Processing (C&P) and Measurement and Control (M&C) facilities. The team initiated MOC audits and developed the

Management of Organizational Change procedure. In addition, the team developed and conducted API RP 754 training, updated the Pre-Startup Safety Reviews (PSSR) procedure and checklist, and updated PHA and PSSR trainings. The Process Safety team revised and focused the Process Safety Management training to reach a larger population within Gas Operations.

**Learn from Experience.** PG&E strives to continuously improve in process safety. Process Safety engineers support investigations and lead cause evaluations, as part of the CAP process [see Table 26]. Cause evaluations are conducted to identify the cause of an incident, issue, or why an error occurred, to implement recommendations or safeguards that will reduce the risk (severity and/or probability) of recurrence and to apply continuous improvement. In some cases, for select incidents (e.g., dig-ins) the team bundles incident causes together to perform a Common Cause Evaluation. These evaluations include the identification and implementation of corrective actions so that PG&E can reduce the risk that similar incidents will occur in the future. Corrective actions resulting from PG&E's investigations are implemented every day to strengthen safeguards. In addition, lessons learned from incidents are shared through Process Safety Moments. Process Safety Moments are a standing agenda item within Gas Operations' monthly Risk and Compliance Committee (RCC) meetings. Cross functional teams are assigned to present Process Safety Moments during these RCC meetings.

# IV. Asset Management

PG&E builds, operates, and maintains natural gas infrastructure to transport, store, and deliver gas to customers over Northern and Central California. PG&E faces inherent risks associated with operating an asset system that passes through populated areas and a wide variety of terrain. The three primary risks confronting PG&E's natural gas system are a loss of gas containment, a loss of gas supply, and an inadequate response to emergencies. The third component of PG&E's Gas Safety Excellence Management System is an asset management system to address these categories of risk and find the balance between asset risk, cost, and performance. The basis of achieving safety through asset management is to know PG&E assets and their condition, understand the risks to those assets, implement risk reduction strategies, and optimize asset risk, cost, and performance. The following section describes PG&E's asset management system, the asset families, how PG&E's Gas Operations manages risk, and the current risk portfolio.

## 1. Asset Management System

PG&E maintains an asset management system to help drive the business toward achieving its commitment to the safe, reliable, affordable management and operation of PG&E's gas assets. Using the international Publicly Available Specification (PAS) 55-1, International Organization for

Standardization (ISO) 55001, and API 1173 standards as guidance, PG&E's asset management system focuses on:

- Identifying and reducing operational and enterprise risk;
- Maintaining an asset management framework and directing organizational focus on the most important asset risks and opportunities;
- Proactively managing the condition of gas assets; and
- Meeting or exceeding the requirements of federal, state, and local codes, regulations and requirements in an environmentally sustainable manner.

The Gas Safety Excellence Policy (TD-01)[11] lays the foundation for PG&E's Gas Asset Management system, while the vision and strategy for enhancing the system is documented in the Strategic Asset Management Plan. PG&E also maintains risk-based Asset Management Plans for each of its nine gas asset families. Finally, PG&E reports regularly to the California Public Utilities Commission (CPUC) on its safety and reliability investments.[12]

## 2. Asset Family Structure

Since assets can face different types of risk, PG&E developed an asset family structure to recognize and manage these differences, yet drive consistency in the way PG&E thinks about and addresses risks.

PG&E identified nine asset families within Gas Operations which are illustrated in Figure 10:

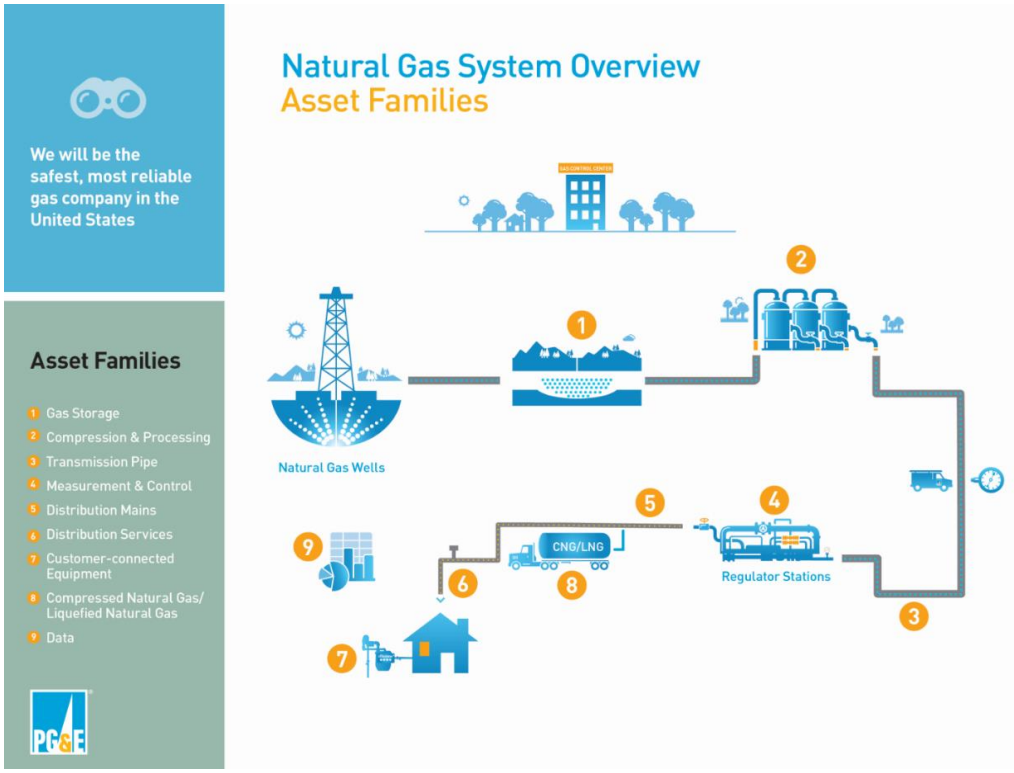



**Figure 10 – Natural Gas System Overview – Asset Families**

Each asset family has an Asset Family Owner who is responsible for knowing the asset condition and the risks to the assets, and developing a risk-based Asset Management Plan, which is a 5-year plan for managing gas assets. For changes to PG&E's Asset Management Plans, please see Attachment 4**.**

By associating each asset with a family, and designating an Asset Family Owner, Gas Operations works to (1) adequately identify each threat; (2) appropriately assess the condition of the asset and the quality of the data about the asset; (3) identify and assess the threats and risks facing the asset; and (4) develop and execute effective mitigation efforts. The Asset Family Owner leads the preparation of the Asset Management Plan for each asset family that describes:

- Asset inventory and condition
- Asset threats and risks
- Desired state for the assets and strategic objectives for achieving desired state
- Programs and risk mitigations
- Areas for continual improvement

These Asset Management Plans are living documents evolving as new asset information becomes available. The following section summarizes the types of assets in each family, the function these assets serve in the gas system, and progress towards achieving Asset Management Plan objectives.

## a) Gas Storage

Figure 11 – Rig and Well Platform

The Gas Storage Asset Family includes PG&E's owned and operated underground natural gas storage facilities at McDonald Island, Los Medanos, and Pleasant Creek. In concert with the Compression and Processing Asset Family, these assets perform a key role in system reliability. The primary assets within this family include 115 storage wells, 14 miles of transmission pipe, well controls for each injection and withdrawal well, and 3,404 acres of storage reservoirs with over 102 billion cubic feet of working gas capacity.

The Gas Storage Asset Management Plan describes the strategy for mitigating and managing risk for this asset family and achieving the established asset management objectives. Examples of key objectives included in the Asset Management Plan are shown in Table 2.

Furthermore, as a result of the 2015 SoCalGas Aliso Canyon incident that resulted in an uncontrolled flow of gas propagating from the ground to the wellhead, the underground storage industry has seen a major shift in the requirements around design, risk and integrity management, and Operations and Maintenance (O&M) for wells and reservoirs. The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) issued its Interim Final Rule in January 2017 adopting all of API RPs 1170[13] and 1171;[14] the Division of Oil, Gas and Geothermal Resources (DOGGR) issued its final regulations on June 29, 2018 with an effective date of October 1, 2018. In response to

these regulatory changes, PG&E's Gas Storage Asset Family completed an evaluation of DOGGR and PHMSA regulations, amended its Risk and Integrity Management Plan, and drafted a 7-year plan to meet the deadlines established by the regulations.

| Table 2 – Gas Storage Asset Management Plan Objectives and Progress To-Date | |
|---|---|
| **Overall Objective/Goals** | **Progress Towards Goal** |
| Complete baseline well production casing assessments on 115 wells by 2025 | Number of baseline assessments performed:<br>2013 – 2016: 27 wells<br>2017: 8 wells<br>2018: 13 wells |
| Evaluate and incorporate Well Integrity Management Plan (WELL) enhancements | 2016: Submitted final WELL documentation to DOGGR for approval and identified improvements to WELL to incorporate in scheduled revisions of the publication.<br>2017: Published updates of WELL to include enhanced design.<br>2018: Amended Risk & Integrity Management plan and submitted to DOGGR in April 2018. Completed evaluation of final DOGGR regulations when issued. |
| Assess work on transmission pipeline through Transmission Integrity Management Program (TIMP) | 2016: Completed written monitoring and assessment plans; Began development of 10-Year Storage Pipe Plan to assess pipe integrity.<br>2017: 2019 Gas Transmission and Storage (GT&S) submission included funding request for strength testing pipeline in the Storage Asset Family.<br>2018: Replaced 1.65 miles of transmission pipe. |
| Continue Process Hazard Analysis (PHA) and Pre-Startup Safety Reviews (PSSR) on all well, surface equipment, and pipeline in storage asset family | Number of PHAs and PSSRs complete:<br>2014: 2 PHAs and 0 PSSRs<br>2015: 3 PHAs and 7 PSSRs<br>2016: 4 PHAs and 11 PSSRs<br>2017: 2 PHAs and 10 PSSRs<br>2018: 15 PHAs and 5 PSSRs |

The Gas Storage Asset Management Plan describes these objectives in more detail.

## b) Compression and Processing (C&P)

PG&E's C&P facilities move gas from receipt points to customer delivery locations and provide for injection and withdrawal of gas at PG&E's underground gas storage facilities. Gas processing equipment provides gas that is free from particulates and is sufficiently dehydrated and odorized so that it can be transported to the gas transmission and distribution systems meeting quality requirements. The C&P asset family includes nine transmission compressor stations. Storage compressors are also installed at PG&E's three underground storage facilities. Major assets include the 38 company-owned compressor units, as well as associated equipment such as filter-separators, pumps, motor control centers, station piping, among others. Additionally, this asset family includes approximately 100 gas odorizer units installed systemwide. Together, stations support the system's reliability and the odor added to gas helps keep PG&E customers safe when gas arrives at their service point.

Figure 12 – PG&E's Burney Compressor Station

The C&P Asset Management Plan describes PG&E's roadmap for achieving strategic objectives related to the C&P assets. Key strategic objectives for C&P assets include the following:

| Table 3 – Compression and Processing Asset Management Plan Objectives and Progress To-Date | |
|---|---|
| **Overall Objective/Goal** | **Progress Towards Goal** |
| Reduce total number of compressor unscheduled shutdowns by 10 percent over two-year average. | Number of unscheduled shutdowns (including rental units) per year: 2018 Target = 245; 2018 Actual = 214 |
| Evaluate 100 percent of transmission station features by end of 2019. | Improved actual/target production ratio year-over-year from 2016-2018. Added additional assets to scope. Actively working to improve data accessibility. |
| Apply Facility Integrity Management principles to all stations by 2025. | Facility Integrity Management Program (FIMP) Maturity model was developed in 2015.<br>FIMP maturity score currently 34 percent based on 2018 re-baselined model. |
| Complete physical security upgrades at critical facilities by 2023. | Stations currently being completed according to schedule. |
| Complete critical documents defined by TD-4551S for all facilities by 2021.[(a)] | Full-scale production implemented. Drafted eight procedures to support production. |

(a) See Attachment 9.

The C&P Asset Management Plan describes these objectives in more detail.

## c) Transmission Pipe

The Transmission Pipe asset family consists of approximately 6,600 miles of line pipe and major components, such as valves and fittings, used in transporting natural gas.[15] PG&E's Transmission Integrity Management Program (TIMP) governs how PG&E identifies and evaluates risks, reduces risk through risk mitigation activities, and assesses integrity performance within the Transmission Pipe asset family. TIMP is a core foundation of PG&E's ongoing efforts to provide safe and reliable service, consistent with industry best practices, and based on the federal TIMP regulations.[16] The Transmission Pipe Asset Management Plan describes the roadmap for mitigating and managing risk for this asset family and achieving the established asset management objectives. The plan's objectives include the following:

**Figure 13 – L-131 Newly Installed Transmission Pipe**

| Table 4 – Transmission Pipe Asset Management Plan Objectives and Progress To-Date | |
|---|---|
| **Overall Objective/Goal** | **Progress Towards Goal** |
| Apply integrity management principles to transmission pipelines covering 100 percent of population living along transmission pipelines by 2030 | 84 percent of population living within potential impact radius (PIR) covered by Integrity Management principles.<br>Implemented a crack management program.<br>Achieved ILI progress targets. 32.2 percent of system is now piggable.<br>Completed Line 132 integrity assessment.<br>Replaced 4.8 miles of Line 131 in Livermore (Figure 13). |
| Meet 100 percent of system capacity obligations and eliminate high risk manual operations in peak day conditions by 2021 | Eliminated 2 high risk manual operations.<br>Line 147 pressure restored, improving reliability.<br>Completed Moraga pipeline work, improving capacity.<br>Implemented load forecasting methodology refinements |
| Update PG&E's gas transmission assets and technology to improve recognition and response to significant transmission incidents by 2021 | See Section IV.7.a for additional information on system visibility progress.<br>Installed 46 automated valves.<br>Installed 15 local actuators to improve isolation time. |
| Maintain a first quartile Damage Prevention program to further reduce transmission dig-ins | See Section IV.5.a for more information on PG&E's Damage Prevention Program and progress.<br>See Section IV.5.b for more information on line marker progress. |

The Transmission Asset Management Plan describes these objectives in more detail.

## d) Measurement and Control (M&C)

PG&E's M&C assets monitor, measure, and control pressure and flow within the gas transmission and distribution systems. The assets in this family perform a critical role in system safety by protecting downstream assets from system pressure excursions and gas quality degradation. Additionally, in concert with the C&P Asset Family, these assets perform a key role in overall system reliability.

Figure 14– M&C Simple Station-Above Ground

The physical assets within this family include three gas terminals, 385 gas transmission stations (both simple and complex), 422 transmission large volume customers, 75 automated valve sites, 2,476 distribution district regulator stations, 2,147 distribution high pressure regulating sets, 26 large customer meter sets, and 48 gas quality analyzers. PG&E's M&C equipment is located above and below ground, as well as within vaults and buildings. Examples of M&C simple transmission stations are shown in Figures 14 and 15.

Figure 15 – M&C Simple Station-Vaulted

The M&C Asset Management Plan describes PG&E's roadmap for achieving strategic objectives related to the M&C assets. Key strategic objectives for M&C assets include the following:

| Table 5 – Measurement and Control Asset Management Plan Strategic Objectives and Progress To-Date | |
|---|---|
| **Overall Objective/Goal** | **Progress Towards Goal** |
| Apply Facility Integrity Management principles to all transmission and distribution stations by 2025. | FIMP Maturity model was developed in 2015.<br>FIMP maturity score currently 34 percent based on 2018 re-baselined model. |
| Install secondary overpressure protection at 50 percent of H-14 facilities within 5 years. | Large overpressure (OP) events per year:<br>2014 – 6; 2015 – 7; 2016 – 10; 2017 – 11; 2018 – 5. Strategy for mitigation of facilities that are most susceptible to large OP events has been developed and is in execution. |
| Complete physical security upgrades at critical facilities by 2023. | Stations currently being completed according to schedule. |
| Accomplish obsolescence management based on condition, maintaining regular turnover of the fleet. | Continuing station rebuilds; developed process to manage controls obsolescence and piloting processes for additional equipment types. |
| Complete critical documents defined by TD-4551S for all facilities by 2021.[(a)] | Full-scale production implemented. Drafted eight procedures to support production. |
| Evaluate 100 percent of transmission station features by 2019. | Improved actual/target production ratio year-over-year from 2016-2018. Added additional assets to scope. Actively working to improve data accessibility. |

(a) See Attachment 9.

The M&C Asset Management Plan describes these objectives in more detail.

## e) Distribution Mains and Services

**Figure 16 – A Distribution Main Replacement Project**

This asset family includes over 42,800 miles of pipeline that connects to the gas M&C asset family on the upstream side and transports natural gas to customers throughout the service area. It also includes over 3.5 million service lines that deliver gas from the distribution mains to the assets in the Customer Connected Equipment (CCE) family on the downstream side. The programs associated with the Distribution Mains and Services asset family are focused on the inspection, analysis, and replacement of Distribution Mains and Services assets. PG&E continues to identify and assess threats to Distribution Mains and Services assets and works to mitigate those threats, including through its Distribution Integrity Management Program (DIMP). Some key strategic objectives include the following:

| Table 6 – Key Distribution Mains and Services Metrics | |
|---|---|
| **PG&E's Commitment to Safety** | **Progress Towards Goal** |
| Achieve 1st quartile for 3rd-party dig-ins in 2018 | PG&E set a 1st quartile 2018 target of 1.84 dig-ins per 1,000 tickets. In 2018, PG&E experienced 1.61 dig-ins per 1,000 tickets and outperformed the target for 2018. |
| Achieve a replacement rate that limits asset age to 100 years by 2030 | 2013: 69 miles installed<br>2014: 66 miles installed<br>2015: 102 miles installed<br>2016: 120 miles installed<br>2017: 145 miles installed (exceeded the target of 130 miles)<br>2018: 165 miles installed (exceeded target of 163 miles) |
| Identify all potential cross-bores and remediate by 2023 | Inspections planned 2013 through 2018: 183,070<br>Inspections completed 2013 through 2018: 181,430 |

The Distribution Mains and Services Asset Management Plan describes these objectives in more detail.

## f) Customer Connected Equipment (CCE)

The CCE Asset Family is composed of approximately 4.5 million meters and associated regulators, over-protection devices, shut-off valves, piping, and fittings that connect the gas distribution service to the customer. Customer meters are used to measure gas usage to support the billing function.

Figure 17 – PG&E Employee Working on CCE

The CCE Asset Management Plan provides an overview of the CCE assets, threats to these assets and efforts underway to manage these threats. The plan presents the asset inventory, an assessment of condition and overview of key risks to the CCE assets. The plan also includes long term strategic objectives and an overview of the key programs in progress to mitigate these risks. The plan's key objectives are included in Table 7:

| Table 7 – Customer Connected Equipment Asset Management Plan Strategic Objectives and Progress To-Date | |
|---|---|
| **PG&E's Commitment to Safety** | **Progress Towards Goal** |
| Limit the steady state backlog of 60,000-70,000 non-hazardous meter set leaks for repair annually | 2018 End of Year Inventory: 84,571 (developing a plan to get back on track with this strategic objective). |
| Identify and remove problematic regulators by 2018 | 1,661 replaced in 2018 vs 1,300 planned. |

The CCE Asset Management Plan describes these objectives in more detail.

## g) Liquefied Natural Gas and Compressed Natural Gas

The Liquefied Natural Gas/Compressed Natural Gas asset family consists of portable assets that provide natural gas supplies to offset or supplement pipeline flowing supplies for planned outages, winter peak load shaving, unplanned outages, and in emergency situations. The Liquefied Natural Gas/ Compressed Natural Gas asset family consists of over 200 portable Liquefied Natural Gas and

Compressed Natural Gas units. In 2018, there were no loss of containment incidents for portable assets [see Table 8].

The Liquefied Natural Gas/ Compressed Natural Gas asset family also includes 32 Compressed Natural Gas station assets to supply the natural gas that fuels PG&E and third-party vehicles and provides very high-pressure gas supply to the portable Compressed Natural Gas equipment. Over the last few years, PG&E has instituted an industry-leading inspection program to assure the integrity of customer Compressed Natural Gas vehicle fuel systems. In 2018, 100 percent of PG&E's natural gas fueling customers authorized to fill at our stations submitted their 3-year vehicle certificates of inspection. In 2018, there was 1 significant loss of containment incident for Compressed Natural Gas Station assets.

**Figure 18 – A Large-scale LNG Injection Site**

| Table 8 – Liquefied Natural Gas/Compressed Natural Gas Safety Success | |
|---|---|
| **PG&E's Commitment to Safety** | **Progress Towards Goal** |
| Driving towards zero significant liquefied natural gas/compressed natural gas loss of containment incidents | 2018 Activities: Continued maintenance of Liquefied Natural Gas/Compressed Natural Gas equipment and assets. Liquefied Natural Gas/Compressed Natural Gas equipment training development and operating training. |
| Implementing an industry-leading inspection program to improve safety inspection certifications from less than 20 percent to 99 percent of Compressed Natural Gas fuel customer vehicles | 2018: 100 percent of natural gas fueling customers authorized to fill at our facilities have submitted their presented 3-year cylinder certification. |
| Reduce risk of portable natural gas transportation traffic incidents by reducing equipment issues through an improved maintenance program | 2018: Continued maintenance of Liquefied Natural Gas/Compressed Natural Gas portable over-the-road assets by dedicated fleet mechanics have resulted in continued decrease of transport incidents. |

The Liquefied Natural Gas and Compressed Natural Gas Station Asset Management Plan describes these objectives in more detail.

## h) DATA

In 2018, PG&E Gas Operations determined that creating an asset family specifically for data is consistent with industry best practice and will provide the appropriate attention and resources to the essential data sets required for the safe and efficient operation of PG&E's gas business. Data should be properly managed to have an appropriate life cycle, generation and disposal considerations, and quality control check points. Other asset-intensive organizations, such as transit authorities and rail companies, employ data asset management strategies, and PG&E is leveraging a similar approach. The benefits expected from implementing this data management approach include a strategic approach to data

management, clear accountability for data management and ownership, enabling efficient business decisions, reducing/eliminating duplicative data clean-up efforts and redundant data analyses, prioritizing most impactful data management initiatives, optimized asset life cycle decision making, enhancements in risk modeling (probabilistic) and quantifying risk reduction, and ability to streamline data collection efforts, thus reducing burden of data collection on field personnel.

To achieve this and to the extent possible, PG&E will leverage the existing asset management framework currently utilized for physical assets. Strategic goals for the gas data asset family include:

- Developing an Asset Management Plan for data in Gas Operations;
- Developing an asset register with essential datasets and pertinent metadata including the quality, condition, and location of the data;
- Developing a framework to assess risk for Gas Operations data;
- Developing data governance document including clearly defined data owners, stewards, and systems of record; and
- Improving completeness and accuracy of digital data to support data-driven risk management and work prioritization by 2022.

## 3. Risk Management Process

Transporting natural gas involves moving a flammable product under pressure. As a result, risk management is an important part of the natural gas business. PG&E's Enterprise and Operational Risk Management team prioritizes risks based on how likely an incident is to occur and how severe it might be. While the hazards and risks associated with natural gas are inherent, multiple layers of protection placed on top of one another safeguard against the failure of any one layer. Therefore, PG&E builds in multiple layers of protection into Company processes and plans.

To identify and address risk, PG&E follows a comprehensive enterprise and operational risk management process. PG&E's Enterprise and Operational Risk Management plans allow PG&E to manage assets and risks at an enterprise and operational level. PG&E defines "Enterprise Risks" as those that could have more than one fatality[17] or potentially have a catastrophic impact.[18] Enterprise Risks and associated mitigation plans are reported to the Board of Directors each year during Session D, typically held in the first to second quarter of each year. Session D is intended to reflect the highest risks to the Company; mitigation of these risks is addressed in the corporate strategy and the executable investment plans as part of Session 1 and Session 2, respectively.

Operational risks are actively managed at the Line of Business level, with oversight provided by each Line of Business's RCC, which meets monthly. Each Line of Business RCC is charged with oversight of risk management activities within the LOB including, but not limited to, reviewing risk assessments, approving risk response plans, and overseeing their implementation. By assessing and managing risks from both points of view, PG&E can better manage the interdependencies and drive for consistency in risk management across the Company. In addition, this process increases senior management and board engagement in risk-informed decision-making by involving them in decisions as the process unfolds, and gives those individuals charged with managing specific assets line of sight to other risks in the enterprise. Since the appointment of the Federal Monitor in 2017, the monitor has been actively engaged in PG&E's risk analyses and helping to improve operations. For example, the monitor attends and participates in Gas Operations' RCC meetings, and also is actively engaged in our integrity management analyses.

**Figure 19 – A PG&E Welder**

Gas Operations identifies, assesses and ranks its risks in a Risk Register in accordance with the Enterprise Operational Risk Management guidelines. The Gas Operations Risk Register is governed by the Gas Operations RCC. Gas Operations' top risks are communicated to PG&E's executive leadership team at Session D. Risks, including the key risks for each asset family identified during Session D, are captured within the Asset Management Plans, mitigation programs, and work projects. As the result of the risk refresh process[19] and the 2018 Session D, Gas Operations identified 32 risks. Of these 32 risks, 5 were enterprise risks and are reflected in Table 9 below.

| Table 9 – 2018 Gas Operations Enterprise Risks | |
|---|---|
| **Risk** | **Description of Risk and Risk Drivers** |
| Transmission Pipeline Failure – Rupture With Ignition | Rupture of transmission pipeline may result in loss of containment and/or uncontrolled gas flow leading to potential public safety issues, prolonged outages, property damages and/or significant environmental damage.<br><br>The drivers of this risk include: External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing Related Defects, Welding/Fabrication Related Defects, Equipment Failure, Weather and Related Outside Forces – Land Movement (including Seismic), First, Second, and Third-Party Damage, and Incorrect Operations. |
| Failure to Maintain Capacity for System Demands | The risk of not maintaining adequate capacity to meet customer demand on the gas system may result in customer curtailments, controlled/uncontrolled gas outages, gas surge-backs into homes, serious injury, and possible fatality.<br><br>The driver of this risk is performing safety related work in a constrained system during winter when demands are high. |
| M&C Failure – Release of Gas With Ignition Downstream | The risk of failure at a gas M&C transmission or distribution facility with loss of pressure control may result in loss of containment with ignition downstream at customer location.<br><br>The drivers of this risk include Incorrect Operations and Equipment Related Defects. |
| Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore | The risk of release of gas with ignition on distribution facilities (Non-Cross Bore) may result in loss of containment, migration, and ignition of gas, leading to safety impact and/or property damage.<br><br>The drivers of this risk include: Corrosion, Manufacturing Related Defects, Material or Welding Related Defects, Equipment Failure, Excavation Damage, Incorrect Operations, Natural Forces, and Other Outside Force Damage. |
| Natural Gas Well Failure – Loss of Containment With Ignition at Storage Facility | The risk of failure at gas storage facility (reservoir) may result in loss of containment with ignition leading to significant impact on public or employee safety, prolonged outages or net replacement of supply, property damage and/or environmental damage.<br><br>The drivers of this risk include: Internal Corrosion and/or Erosion, External Corrosion, Third-Party Damage, and Welding/Fabrication Related Defects. |

Risks impacting more than one Line of Business are called Cross-Cutting Risks. These risks also follow the enterprise and operational risk management process. The Cross-Cutting Risks are owned by a single Line of Business with other impacted Lines of Business providing their input and subject matter expertise during the risk management process. Gas Operations is impacted by several cross-cutting risks owned by other LOBs as displayed in Table 10 below.

| Table 10 – Enterprise Risk Management: Cross-Cutting Risks | |
|---|---|
| **Risk** | **Risk Description** |
| Records and Information Management (RIM) | Not implementing fully an effective RIM program and controlling data quality may result in the failure to construct, operate, or maintain a safe system. Additionally, inadequate business processes and system controls related to the collection, maintenance and disposition of records and information can result in non-compliance, security gaps, and insufficient or inaccurate data for critical decision making. |
| Cyber Attack | Introduction of malware or execution of commands by authorized and unauthorized users or hackers, use of infected removable media, exposure to phishing, visitation to infected websites, or exploitation of remote connections may lead to the disruption of the confidentiality, integrity, and/or availability of business control applications, computing, data, or networks. |
| Contractor Safety | Failure to comply with contractor pre-qualification and field oversight processes may result in serious injury and/or fatalities. |
| Employee Safety | The inability to fully identify, evaluate, and mitigate workplace exposures may result in serious injury and/or fatalities. |
| Emergency Preparedness and Response | The risk of inadequate plans and poor response execution to a catastrophic emergency may result in safety concerns, extended outages, regulatory action, and reputational damage. This risk includes business continuity for the enterprise outside of the event. |
| Skilled and Qualified Workforce | The risk of an employee or non-employee working without meeting appropriate legal, regulatory and PG&E-defined requirements. "Requirements" include qualifications (skills, competencies, abilities, knowledge, certifications) for the defined job or work. This may result in one or more of the following: work procedure errors, legal or regulatory non-compliance, cybersecurity breaches, localized outages, damage to property or assets belonging to PG&E, another corporation, a government organization or a member of the public, injury or death to an employee or member of the public. |

PG&E continues to improve its risk management process. PG&E is an active participant in the CPUC's proceedings to advance a "risk-informed" process. In Decision 14-12-025, the CPUC adopted a risk-based decision-making framework into the Rate Case Plan for energy utilities. The framework includes the Safety Model Assessment Proceeding (S-MAP) and the Risk Assessment Mitigation Phase (RAMP). S-MAP's focus is on the models each utility is using to evaluate risk with the intent of developing a single model for all utilities. RAMP's focus is on risk mitigation, alternatives analysis, risk spend efficiency, and a quantitative measure of expected risk reduction. PG&E filed its first RAMP on November 30, 2017. The five Gas Operations enterprise risks listed in Table 9 were included in the RAMP submittal.

## 4. Records and Information Management

PG&E's Gas Operations records management team, as part of the Enterprise Records and Information Management (ERIM) Program, focuses on the deployment of consistent, integrated processes that support records development associated with operational safety, regulatory compliance, and knowledge management. ERIM works with all of PG&E to assess and inventory physical and electronic records, establish specialized plans for vital records in partnership with the business, and monitor the process controls for protecting and storing records. Examples of RIM accomplishments in 2018 include:

- Provided key records management support for Gas Operations' PAS 55/ISO 14001 Certifications; Minor non-conformance for records lifted;
- Updated and recertified Gas Operations records inventory;

- Developed 26 records process maps for identified Gas Operations business processes;
- Continued physical records remediation in Gas Operations field offices;
- Completed 18-month program to assess all Gas Operations field offices to identify RIM Program gaps; completed all identified remediations; and
- Restructured Gas Operations RIM team to align with Gas Operations Mega Process structure.

The RIM Ambassador network, composed of Gas Operations staff, continues to be an effective way of communicating records management information throughout the LOB. In addition to the mandatory records training that all PG&E employees receive, the Gas RIM team provides quarterly training to the ambassadors and supports them as they coach their peers in meeting PG&E's recordkeeping requirements. In 2019, these offerings will be available to all of PG&E. Additionally, the full-time ERIM Coordinator network supports all LOBs and all territories throughout PG&E by providing records management resources to the field.

Gas RIM continues to implement and refine the comprehensive roadmap which was initially launched in May 2014. The Gas RIM roadmap defines and tracks progress of projects and initiatives to support compliance and risk reduction. Table 11 details some key RIM roadmap initiatives and drivers.

**Table 11 – Gas Operations Records and Information Management Roadmap Highlights**

| Key Roadmap Initiatives | Roadmap Drivers |
|---|---|
| ERIM Compliance Assessment and Monitoring | • Records-related remedies and recommendations adopted by the CPUC in the San Bruno Order Instituting Investigation (OII) Penalties decision issued in April 2015 and outlined in PG&E's Initial Compliance Plan associated with Investigation 14-11-008, an OII associated with PG&E's gas distribution record-keeping practices.<br>• ARMA International's Information Governance Maturity Model.<br>• Continued certification of PAS 55-1 and ISO 55001, API 1173 and RC 14001. |
| 2019 Records Inventory | |
| Disposition Program Implementation | |

## 5. Mitigating the Risk of Loss of Containment

PG&E takes a proactive approach to reducing the risk of loss of containment, or the unintended release of natural gas. The mitigation programs and projects to address loss of containment vary significantly in size and scope, from actively promoting "Call Before You Dig" and installing pipeline markers over the assets as visual identifiers, to inspecting, testing, and replacing assets that may be deemed beyond their useful lives. PG&E remains focused on identifying the right work to protect the public from a loss of containment incident.

### a) Damage Prevention

Damage Prevention consists of multiple processes working in collaboration to educate contractors and homeowners about safe excavation practices near underground infrastructure. Activities, reviewed

annually and described in the next sections, include Public Awareness, Dig-in Reduction Team (DiRT), Locate & Mark, and Pipeline Patrol & Monitoring.

Damage Prevention includes marking the field location of underground facilities as requested through the Underground Service Alert ("USA") One-Call system—commonly referred to as 811, USA ticket management, investigations associated with dig-ins and damage claims, and Public Awareness. The marking of underground utilities is governed by California Government Code 4216 and the process is driven by industry best practices.

Table 12 describes other key Damage Prevention programs.

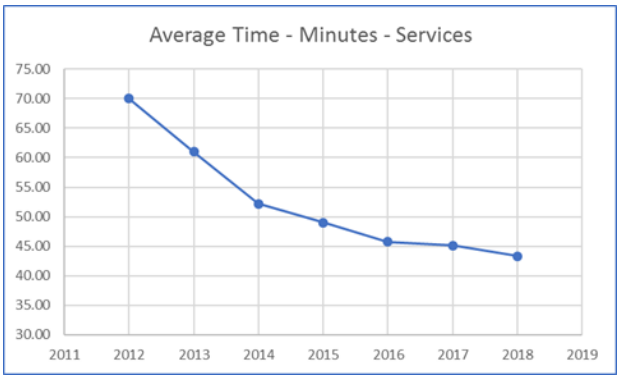
| Table 12 – Damage Prevention Programs | |
|---|---|
| 811 Ambassador | The 811 Ambassador Program provides a response mechanism for PG&E employees to take corrective action when they observe excavation with no delineation or markings. All PG&E employees are 811 Ambassadors. Employees learn how to identify excavation-related delineations and utility operator markings as required by the California One Call Law. If an employee observes excavation without the required marks, they call the Damage Prevention Hotline and in response, a DiRT member is dispatched to the job site to assess whether the excavation complies with California's One Call Law. If the excavation is found to be in non-compliance with California's One Call Law, the DiRT member takes several actions. S/he requests all excavation be stopped, educates the excavator about the requirements of California's One Call Law and the reason for the non-compliance, provides excavation safety materials, and instructs the excavator to correct the noncompliance activity prior to continuing any excavation. In 2018, the Damage Prevention Hotline received 3,001 811 calls. |
| Gold Shovel Standard | PG&E continues to participate in the Gold Shovel Standard. PG&E began this program that is now run by a third-party and available to utilities across the nation. The program sets safety criteria that second-party contractors are required to meet to be eligible to do work on behalf of the Utility. The Gold Shovel Standard became an internationally recognized program, with companies in Canada adopting and implementing its certification requirements. The Gold Shovel Standard program is one way that PG&E is making its own communities safer, but also bringing best safety practices to the industry.<br><br>PG&E requires contractors excavating on behalf of PG&E to obtain the Gold Shovel certification. PG&E acknowledges all contractors who practice safe excavation and monitor offenders who fail to demonstrate safe practices. Unsafe contractors lose their certification. |
| Damage Prevention Manual & Training | Providing clear and concise instruction around dig-in prevention measures like troubleshooting "difficult to locate" facilities. |

In addition, since 2012, PG&E has improved its Shut-In Gas Performance, which tracks the company's ability to quickly stop the flow of gas when the company is notified of potentially dangerous public safety events such as dig-ins, impacts to meters from vehicles, pipe ruptures, explosions, or material failures. The Shut-In Gas performance specifically measures the number of minutes required for a qualified PG&E responder to arrive onsite and stop the flow of gas from PG&E's distribution network. PG&E measures performance for damages impacting either gas service lines or meters/risers

(Services) or damages impacting gas mains. In 2018 PG&E's Shut-In Gas Performance was on average 43.3 minutes for services and 88.77 minutes for mains.

| Table 13 – Shut-In Gas Performance (average number of minutes) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2014 | 20115 | 2016 | 2017 | 2018 |
| Services | 70.00 | 61.00 | 52.20 | 49.00 | 45.76 | 45.16 | 43.30 |
| Mains | 192.00 | 147.00 | 120.77 | 102.80 | 104.43 | 103.78 | 88.77 |

Since 2012, PG&E has improved its overall make safe performance on events involving services by 38 percent, and events involving mains by 54 percent.



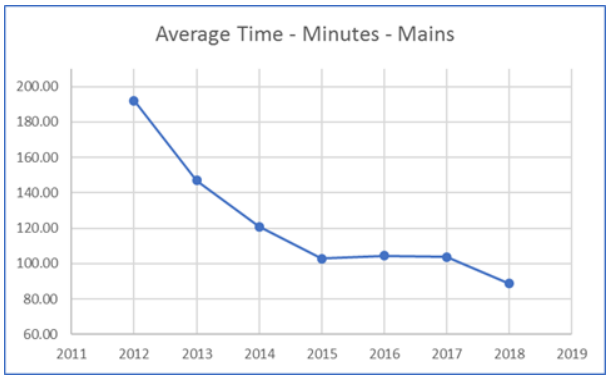




**Figure 20 – Shut-In Gas Performance**

PG&E will continue its efforts to improve its Shut-In Gas Performance.

## i. Public Awareness

PG&E's Public Awareness Program conducts educational outreach activities for excavators, local public officials, emergency responders, and the public who live and work in PG&E's service territory. The program communicates safe excavation practices, required actions prior to excavating near underground pipelines, availability of pipeline location information, and other gas safety information through a variety of methods throughout the year including bill inserts, e-mails, brochures, mass media advertising, press releases and participation in community meetings and events.

**PG&E conducted 226 "811 Call Before You Dig" contractor workshops, reaching over 6,600 attendees, representing over 600 excavation companies or municipalities.**

PG&E communicates gas safety information multiple times each year, and in 2018, reached approximately 4 million paper bill customers and sent over 2 million e-mails to those customers who receive paperless billing. In addition to the bill inserts and e-mail campaigns, PG&E also sent a targeted direct mail piece to over 330,000 non-customers[20] within 1,000 feet of a PG&E gas transmission pipeline, explaining their proximity to the transmission line, information about how to locate nearby gas pipelines, damage prevention measures (811), how to identify gas leaks, and what to do in the event of a gas leak. Additional targeted mailings were sent to school administrators, excavators, emergency responders, public officials, landscapers, sewer and plumbing companies, farmers, homeowner associations, master meter accounts, and those who live or work near PG&E's un-odorized pipelines or storage and compressor facilities. Table 14 identifies highlights from the Program's 2018 activities.


**Figure 21 – Examples of 811 Social Media Campaign**

| Table 14 – Public Awareness Highlights |
|---|
| Developed gas and electric safety activity books for grade school aged children. Promoted the new materials to teachers and day care workers through a Facebook campaign, resulting in over 2,600 additional visits to PG&E's educational resources webpage. |
| Executed a social media campaign targeting homeowners, landscapers and farmers in areas with high damage rates, promoting the importance of calling 811 before digging. These campaigns reached over 214,000 customers. |
| Continued to conduct targeted outreach in cities with a high number of dig-ins. The outreach included job site visits, 811 training for top damaging companies and meeting with local leadership to discuss continued partnership for community safety. These targeted efforts resulted in over 12,000 field visits. |
| Completed 12 bilingual 811 workshops, with a total of 320 participants (farmers, day workers, and unlicensed/soon-to-be contractors). |

### ii. Dig-In Reduction Team

PG&E continues to push for improved performance in dig-in prevention by conducting factual investigations of excavation damage to PG&E's facilities, identifying process improvements to reduce damages, and actively pursuing cost recovery from contractors responsible for excavation damage. The Dig-In Reduction Team is a proactive program that directly and positively affects public and employee

safety by striving to reduce the number of excavation damage incidents. PG&E's Dig-In Reduction programs were instrumental in reducing the average number of dig-ins per 1,000 USA tickets from 1.89 in 2017 to 1.61 in 2018.

Table 15 below provides information on some dig-in prevention projects or process improvements.

| Table 15 – Dig-In Reduction Team Programs Under Damage Prevention | |
|---|---|
| **PG&E's Commitment to Safety** | **Promoting Safety** |
| Dig-in Reduction Team (DiRT) | Deploys investigators to oversee and enhance PG&E's ability to investigate dig-ins, patrol active dig-ins and excavations, and intervene when unsafe activities are identified. |
| Pipeline Patrol | Identifies and intercepts threats to the transmission system via aerial and ground patrolling. Pipeline Patrol notifies DiRT as needed. DiRT will perform tasks listed above, as appropriate. |
| 811 Workshops | Conducts safe digging workshops throughout the service territory. |

* Beginning January 1, 2016, contractors who wish to excavate or subcontract out excavation work for PG&E must obtain Gold Shovel Standard Certification by making a commitment to safe digging practices in accordance with the California "One Call Law" (California Government Code 4216) and the Common Ground Alliance best practices for excavation.

### iii. Locate and Mark Program

The Locate and Mark Program is designed to mitigate the potential risk of damage to underground facilities by identifying and marking assets for potential excavators within a 48-hour window. Federal pipeline safety regulations[21] and California state law[22] require that PG&E belong to, and share the cost of operating, the regional "one-call" notification system. Builders, contractors, and others planning to excavate, must use this system to notify underground facility owners, like PG&E, of their plans to excavate. PG&E then provides the excavators with information about the location of its underground facilities, both natural gas and electric. Information is typically provided by having a PG&E locator visit the work site and place color-coded surface markings to show where underground pipes and wires are located. Because of its large service territory, PG&E belongs to two regional one-call systems which share a common toll-free, 3-digit "811" telephone number. The California one-call systems are commonly referred to as Underground Service Alert ("USA"). In 2018, PG&E received over 1.1 million USA tickets.

In December 2018, the CPUC opened an OII involving data that PG&E maintained from 2012 to 2017 regarding the timeliness with which it responded to 811 notifications.[23] PG&E takes the issues raised in the OII seriously and has worked hard to correct them since they were brought to senior management's attention. As such, PG&E implemented a comprehensive corrective action plan (Compliance Plan) with demonstrated results. This Compliance Plan sets out thirty corrective actions across five core areas: Cultural, Process & Procedures, Tools & Technology, Employees & Contractors, and

**Exceeding federal requirements, PG&E's Pipeline Patrol Program seeks to conduct patrols of the entire transmission system monthly.**

Internal & External Controls. Of the Compliance Plan's 30 corrective actions, 22 are complete, and the others are in progress and are being closely monitored.[24] PG&E has been and continues to be on a mission to improve its safety, compliance and ethics culture and to foster a non-retaliatory environment where all employees can confidently and safely speak up, and leaders are consistently listening to and following up on issues raised by employees. Such transformations take time, and PG&E is steadfastly committed to this important work.

### iv. Pipeline Patrol and Monitoring

Pipeline Patrol is a federally required activity that is essential to protecting the integrity of PG&E gas transmission facilities from external threats and in doing so, helps to increase public safety. Patrol is performed by operator-qualified personnel who observe surface conditions near the Right-of-Way (ROW) of transmission pipelines and selected distribution facilities. Patrollers identify and report a variety of observations including abnormal operating conditions (AOC), potential threats to pipeline integrity (e.g., digging, farm-field ripping, boring, blasting, etc.), new construction that may affect Class Location or High Consequence Areas, vegetative cover, and structural encroachments.


**Figure 22 – Patrol Aircraft With Wing Mounted Camera**

PG&E primarily utilizes aerial methods to conduct patrols, with ground personnel dispatched to investigate observations made from the air. Exceeding federal requirements, PG&E's Pipeline Patrol Program seeks to conduct patrols of the entire transmission system monthly, as well as meet an internal goal to patrol pipelines located in High Consequence Areas (populated areas) a second time each month, as conditions permit. Special patrols may also be performed following natural disasters or other incidents as necessary. Aerial patrols provide real-time knowledge of on the ground activities and the surveillance helps PG&E to identify and stop unsafe excavation practices before dig-ins occur.

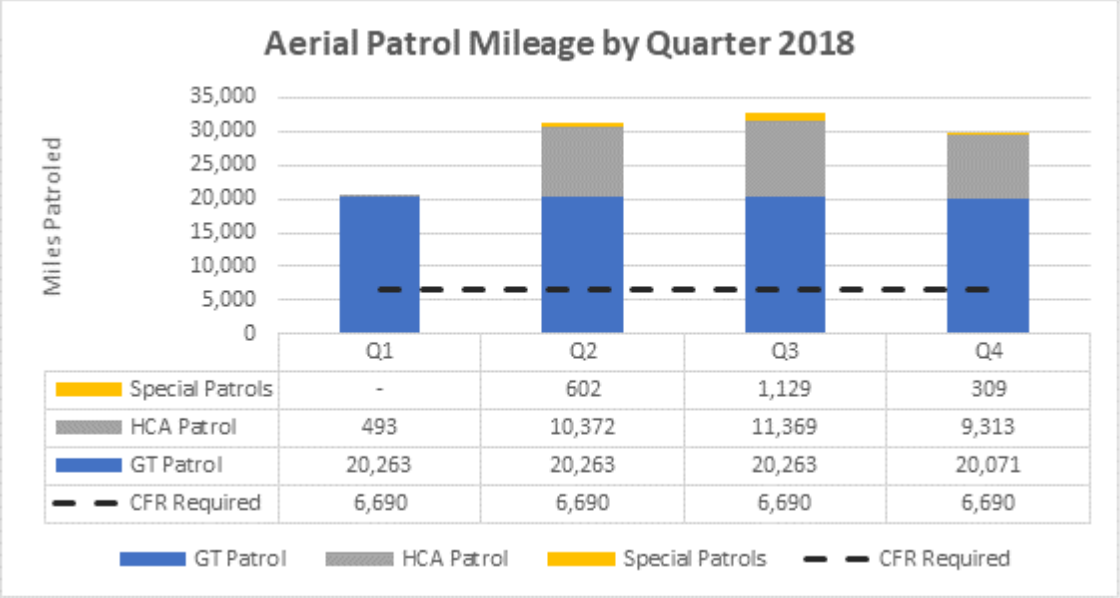



**Figure 23 – Aerial Patrol Mileage by Quarter 2018**

In 2018, pipeline mileage covered by aerial patrols totaled more than 114,488 miles. Patrol Achievements for 2018 include implementation of a Distribution Patrolling Program, revision of Patrol Procedure TD-4412P-07 (see Attachment 5), and continual enhancement of Mobile Solutions for Patrolling.

## b) Pipeline Markers

Pipeline markers and indicators are important damage prevention tools used to indicate the approximate location of the respective pipeline along its route, to prevent "dig-ins" from occurring. Installing markers is required by pipeline safety regulations because markers contribute to public awareness and damage prevention, which in-turn reduces the risk of loss of containment.

Pipeline Markers are signs on the surface above or near the natural gas pipelines located at frequent intervals along the pipeline ROW. The markers are typically found at various important points along the pipeline route including highway, railway, waterway intersections, spans, angle points (bends), and other road crossings. These markers display the name of the operator and a telephone number where the operator can be reached in the event of an emergency. They are meant to be highly visible along the ROW and appear in different forms as the examples in Figure 24.

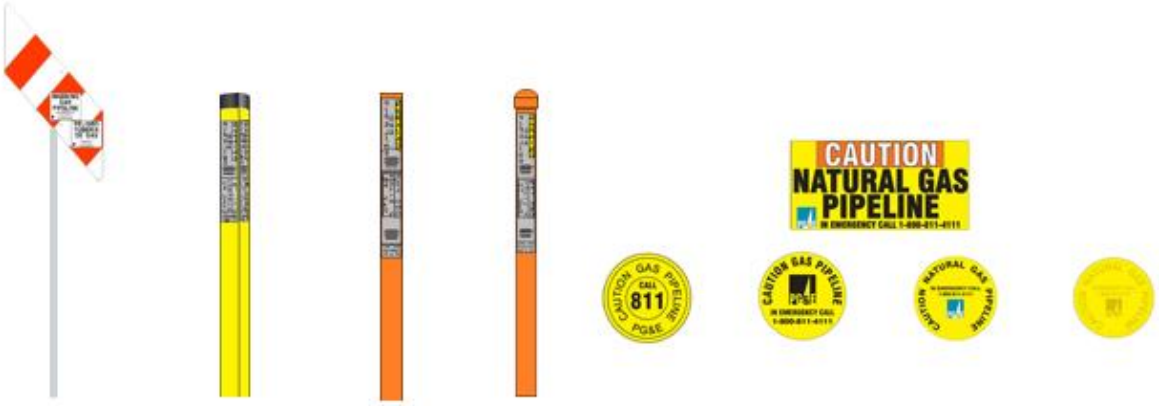



**Figure 24 – Types of Pipeline Markers**

In the event of an emergency or natural disaster, markers may be the only indication to the public and emergency responders that natural gas pipelines are in the area, subject to third-party removal or damage, despite being properly installed.

In 2018, PG&E installed 1695 new markers where road and railroad crossings intersect the pipeline, 378 pipeline markers within a person's unassisted line of sight along the pipeline, and repaired or replaced 531 existing pipeline markers. New decals with current telephone numbers were applied, thereby increasing community safety and gas transmission pipeline visibility above ground.

**Figure 25 – Crew After Completion of the Installation of a New Pipeline Crossing Marker**

## c) Distribution Pipeline Replacement

An important element of providing safe gas distribution service is replacing aging or at-risk assets. PG&E uses relative risk in prioritizing its pipeline replacement projects. Risk factors include age, material type, leak history, cathodic protection, seismic impact, proximity to the public, and other operational factors. In addition to gas main replacement, the program covers related service replacement and meter relocation work.

PG&E has three pipeline replacement programs: Gas Pipeline Replacement Program (GPRP), Plastic Pipe Replacement Program, and Main Replacement Reliability Program. PG&E's objective is to achieve an asset age limited to less than 100 years.

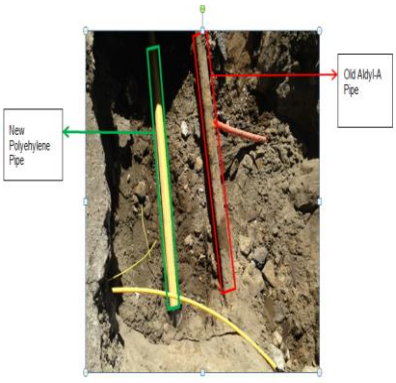



**Figure 26– Old Aldyl-A Pipe and New Polyethylene Replacement**

| Table 16 – Pipeline Replacement | | |
|---|---|---|
| **Gas Pipeline Replacement Program** | **Plastic Pipe Replacement Program** | **Main Replacement Reliability** |
| Over the past 30 years, the GPRP Program focused on the replacement of cast iron and pre-1941 steel pipe, and has enabled PG&E to deactivate all known cast iron main (over 830 miles of pipe). GPRP is now focused on replacing pre-1941 steel pipe. In 2018, the GPRP Program replaced 43.6 miles of pipe. | Since PG&E began its Plastic Pipe Replacement Program in 2012, PG&E has replaced about 410 miles. In 2018, approximately 91 miles of Aldyl-A were replaced. PG&E continues to increase the replacement of Aldyl-A year-over-year in recognition of the approximately 5,000 miles of known inventory. | The Main Replacement Reliability Program focuses on the replacement of pipeline not covered by the GPRP or Aldyl-A programs and will continue to help move the distribution systems average age closer to the national average. In 2018, PG&E replaced 30.5 miles of distribution pipe through this program. |

Figure 27 demonstrates the company's main replacement progress from 2010 to 2018.

## Main Replacement 2010-2018 Actuals

| Program | | | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 14A | GPRP | Replacement of all cast iron and some steel main installed pre-1940 | 24.8 | 28.1 | 23.4 | 31.6 | 26.8 | 27.5 | 30.4 | 36.0 | 43.6 |
| 14D | Aldyl-A | Replacement of Aldyl-A plastic and similar plastic installed pre-1985 | 0.0 | 0.0 | 17.6 | 30.7 | 32.5 | 63.5 | 80.4 | 95.1 | 90.9 |
| 50A | Reliability | Replacement of gas facilities that have reliability concerns but do not qualify for replacement under the GPRP or Aldyl-A Plastic Replacement Programs | 3.7 | 6.4 | 7.9 | 8.2 | 6.6 | 13.7 | 15.8 | 13.8 | 30.5 |
| Total | | | 28.4 | 34.4 | 48.9 | 70.5 | 65.9 | 104.7 | 126.6 | 144.9 | 165.0 |
| Trend | | | | 21% | 42% | 44% | -7% | 59% | 21% | 14% | 14% |

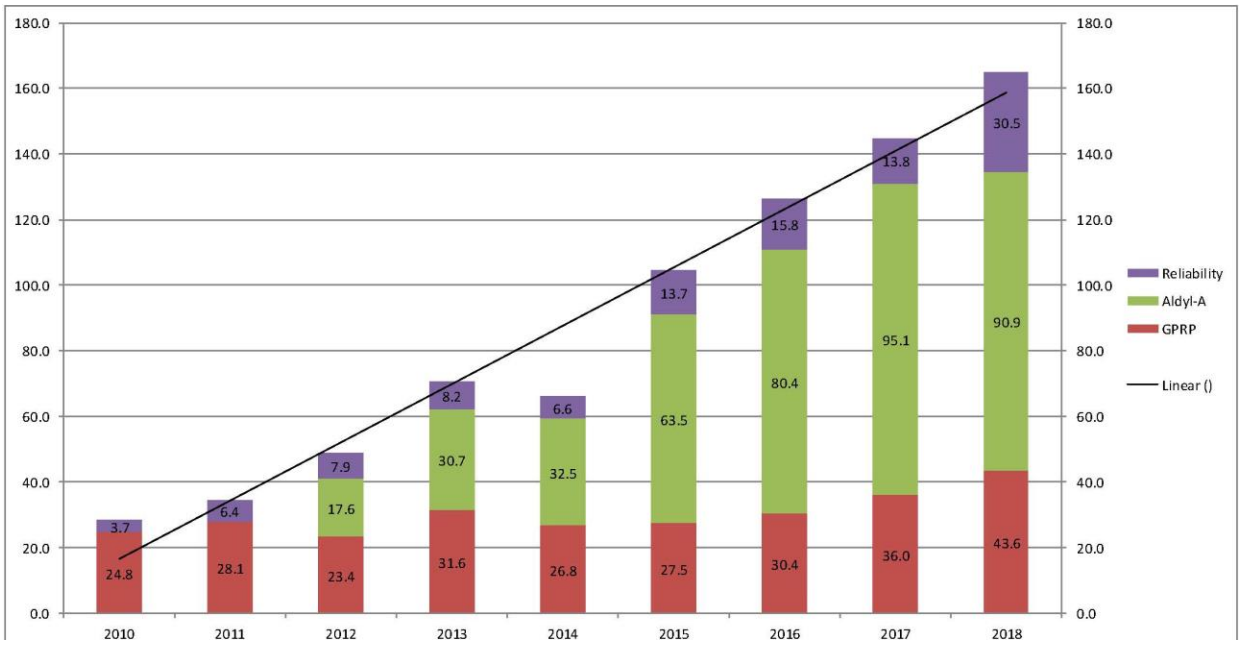



**Figure 27 – Main Replacement Progress 2010-2018 (in miles)**

## d) Cross-Bore Mitigation

A cross-bore[25] is a gas main or service that has been installed unintentionally, using trenchless technology, through a wastewater or storm drain system. PG&E has an inspection program to identify and remediate gas cross-bores, and a public outreach program that provides safety information to PG&E customers, sewer districts, and public works agencies. In addition, PG&E has implemented a Gas Cross-Bore Inspection Program that uses video camera inspections to verify no damage has occurred to sewer lines when using trenchless construction methods on new construction projects.

| Cross Bore Statistics | | | |
|---|---|---|---|
| Year | Inspections Completed | Cross Bores Found | Inspections Planned |
| 2013 | 19,500 | 148 | 25,000 |
| 2014 | 33,570 | 188 | 38,000 |
| 2015 | 23,531 | 100 | 24,000 |
| 2016 | 23,653 | 94 | 23,570 |
| 2017 | 35,131 | 55 | 30,000 |
| 2018 | 46,045 | 46 | 42,500 |

Figure 28 – Cross-Bore Statistics

The goal of PG&E's Cross-Bore Inspection Program is to identify cross-bores by completing inspections of potential conflict locations and repairing all occurrences as they are discovered.

PG&E completed approximately 46,045 inspections in 2018 (bringing the total to 181,430 inspections since 2013). In 2018, PG&E found approximately 1 cross-bore per 1,000 inspections.

## e) Strength Testing

PG&E's transmission pipeline strength testing program is designed to allow PG&E to find pipeline defects that could subsequently cause a rupture or leak, and then repair these defects or anomalies in the pipeline. The strength testing takes a pipeline out of service, clears it of gas, cleans it internally, then fills it (typically with water) to pressures usually at or exceeding 1.5 times the maximum allowable operating pressure (MAOP), consistent with and pursuant to 49 Code of Federal Regulations, Part 192, Subpart J testing and documentation requirements. This process also results in a test record that establishes the operating pressures the pipe can withstand. A secondary benefit of hydrotesting for PG&E is that the pipeline is typically upgraded to allow for navigation of the cleaning tools (pigs), allowing PG&E to run ILI tools at later dates [see Section IV.5.g *In-Line Inspection*]. Thus, hydrotesting is one tool PG&E uses to maintain the margin

Figure 29 – Strength Test in Progress

of safety for the transmission pipeline and reduce the likelihood of future loss of containment incidents that could pose a risk to public safety.

PG&E's goal is to strength test or replace untested transmission pipelines by the end of 2026. Once completed, PG&E will have a test record for its entire gas transmission pipeline system. In 2018, PG&E completed approximately 286 miles of hydrotesting (Table 17). This work brings PG&E to a total of approximately 1,381 miles hydrotested since 2011. The pipeline miles strength tested in 2018 were prioritized based on a risk informed mix of integrity management threats and testing untested pipe or pipe lacking a record of a test.

**Figure 30 – Crew Replaces Vintage Pipe in Livermore**

| Table 17 – Hydrostatic Strength Testing Program | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Strength Test (miles)** | **2011-2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **Total** |
| PSEP | 539 | 135 | N/A | N/A | N/A | N/A | 674 |
| Subsequent Testing | 0 | 0 | 79 | 89 | 253 | 286 | 707 |
| **Total** | **539** | **135** | **79** | **89** | **253** | **286** | **1,381** |

In 2019, PG&E will concentrate on assessing shorter pipeline segment tests addressing National Transportation Safety Board (NTSB) commitments and re-assessing pipeline segments with integrity management threats for both manufacturing related defects and time dependent corrosion threats.

## f) Vintage Pipe Replacement

A significant portion of PG&E's natural gas transmission pipeline system, approximately 47 percent, was designed, manufactured, constructed, and installed before the advent of California's 1961 pipeline safety laws. While age alone does not pose a threat to pipeline integrity, PG&E has determined, consistent with industry practice, that some vintage pipeline features, pipelines with certain welds, bends, and fittings located in areas subject to land movement, are most appropriately managed through replacement.

In 2018, PG&E refreshed its program information using new risk results from the previous year. This update included a revised risk methodology from 2017 which changed our strategic risk prioritization approach to replacing pipe. PG&E redefined high-risk land movement areas, prioritized projects based on total risk, and redefined pipe with lower risk to be monitored for risk change through our In-Line Inspection and Geohazard programs in lieu of replacement or retirement. Due to the revised risk

methodology, PG&E has now identified approximately 146 miles (Tier 1 and Tier 2) of transmission pipe,[26] with some of the characteristics that make it more susceptible to certain construction threats. Of those 146 miles identified, PG&E has further identified approximately 123 miles (Tier 1) of high risk pipe targeting replacement or retirement where vintage fabrication and construction threats interact with high likelihood of land movement in populated areas.[27] Additionally, PG&E is monitoring an additional approximately 1,312 miles of pipeline with girth welds through In-Line Inspection and the Geohazard programs. In 2018, approximately 20.6 miles of vintage pipe was replaced. PG&E plans to mitigate approximately 2.9 miles of vintage pipe in 2019.

**Table 18 – Vintage Pipe Replacement Program**

| | Miles Replaced | Additional Miles Addressed | Percentage of High Risk Mileage Addressed[(a)] |
|---|---|---|---|
| **Pre-2015** | 20.2 miles | 1.3 miles | 20 percent |
| **2015** | 5.9 miles | 12.7 miles | 41 percent |
| **2016** | 6.7 miles | 8.8 miles | 45 percent |
| **2017** | 3.5 miles | 11.5 miles | 61 percent |
| **2018** | 20.6 miles | 0 miles | 74 percent |
| **Program Target:** | 146 miles | | 100 percent |

(a) High risk mileage addressed includes pipeline retirements and mileage replaced in other pipe replacement programs from 2015-2018.

As PG&E continues to monitor and assess characteristics of vintage pipelines interacting with land movement through improved data quality and collection, its replacement or retirements are prioritized by addressing sections of pipeline closest to highest density population areas with a high likelihood of ground movement. At PG&E's current and planned rate, the program will address the risk of pipe containing vintage fabrication and construction threats that interact with high risk of land movement for high population density areas by 2027.

## g) In-Line Inspection

PG&E's In-Line Inspection Program uses technologically advanced inspection tools, often called "smart pigs," to reliably assess the internal and external condition of transmission pipe so that action can be taken when issues are identified. Prior to running an ILI tool in a pipeline, a pipeline must be modified with portals called "launchers" and "receivers," and pipeline features that would obstruct the passage of the tool to make the pipeline piggable must be replaced. After the pipeline is upgraded to accommodate an ILI tool, cleaning and inspection "runs" are conducted to collect data about the pipe. This data is analyzed for pipeline anomalies that must be remediated through the Direct Examination and Repair process where the anomaly is exposed, examined and repaired as necessary. The information from Direct Examination and Repair is used to generate mitigation activities to improve the long-term safety and reliability of the pipeline.

Figure 31 – ROSEN Electro Magnetic Acoustic Transducer (EMAT) Tool Before an Inspection on L-300A

**In-Line Inspection is the MOST RELIABLE pipeline integrity assessment tool currently available to natural gas pipeline operators to assess the internal and external condition of transmission line pipe.**

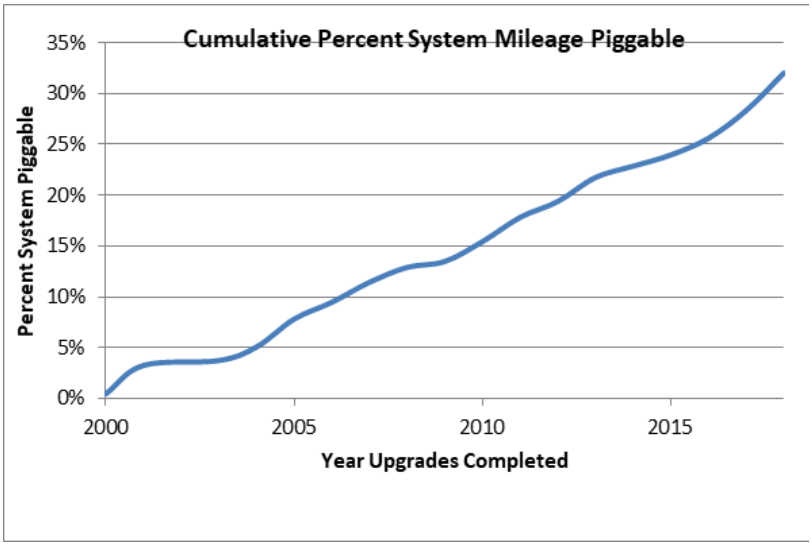



Figure 32 – Progress to-date to upgrade pipelines

The Traditional[28] In-Line Inspection Program is ramping up to complete more projects in the next eight years than ever before to reach the goal of 66 percent total system mileage piggable by 2026. As of 2018, approximately 32 percent of the system is piggable. In 2018 alone, PG&E upgraded 243 miles which is a 12 percent increase to overall piggable mileage. In addition, PG&E inspected a total of 297.4 miles with 139 of those miles assessed with ILI for the first time. Much of PG&E's pipeline was installed decades before in-line inspection was invented. Today, about 35 percent

of the PG&E system is not capable of supporting the running of traditional ILI tools because of design elements like low pressure and/or low flows, small diameter pipelines, and short sections of pipeline or facility configurations, such as drips or blow downs. Figure 32 details PG&E's progress to-date to upgrade pipelines to make them capable of accepting traditional ILI tools.

## h) Corrosion Control

All of PG&E's metallic assets are susceptible to corrosion—a natural, time-dependent process where metal degrades (rusts) due to its interaction with the environment. Gas transmission, storage, and distribution assets primarily composed of steel pipe carrying compressed natural gas may experience degradation due to External Corrosion, Internal Corrosion, or Stress Corrosion Cracking (SCC). External corrosion is degradation of the pipe due to interaction of the steel with the atmosphere, soil (buried piping), and/or water (submerged piping). Internal corrosion is degradation of the pipe due to interaction of the steel with the natural gas being transported. SCC is degradation of the pipe due to cracks induced from the combined influence of tensile stress[29] and a corrosive environment. The material degradation associated with all forms of corrosion may reduce the integrity of steel assets and threaten PG&E's ability to safely and reliably transport natural gas. PG&E assesses the risk of External Corrosion, Internal Corrosion, and SCC independently because each requires a different form of mitigation.

**Figure 33 – PG&E Employee Installing a Galvanic Anode**

Given the risk profile associated with corrosion, PG&E has sought out highly qualified corrosion experts from around the country, enhanced procedures, and incorporated systematic, risk-infomed methodologies to its corrosion control approach. PG&E's efforts are resulting in more accurate data on which to make decisions related to the identification and mitigation of corrosion risks, improving the safety and reliability of PG&E's assets.

For example, PG&E mitigates the threat of External Corrosion by installing assets with appropriate coatings and by applying cathodic protection to buried or submerged structures. Cathodic Protection mitigates corrosion through administering direct current through the soil and/or water to steel piping. Coatings mitigate corrosion by forming a barrier between the steel and environment. As coating systems on buried and submerged piping systems cannot readily be inspected for degradation, the use of cathodic protection in conjunction with coatings provides additional protection for buried or submerged assets.

PG&E also monitors for conditions that may limit the ability to maintain adequate levels of cathodic protection on buried or submerged assets. Such conditions include electrically shorted casings and electrical interference from electric transmission equipment, municipal rail systems, and other operators' corrosion control systems. Overall, corrosion control at PG&E consists of the programs below:

**Table 19 – Corrosion Control Programs**

| Program | Program Description |
|---|---|
| Atmospheric Corrosion | Addresses deterioration of coating systems on assets designed for above ground use. Program includes field inspections and mitigation. |
| Casings | Identifies and remediates electrically contacted cased crossings. |
| Cathodic Protection (CP New, CP Replace, 850 Off) | Designs, installs, and maintains cathodic protection systems to prevent corrosion. In addition, PG&E is surveying and enhancing Transmission CP levels system wide. |
| Close Interval Survey | Collects survey data pertinent to Cathodic Protection levels, coating condition, and other issues at intervals between test points. |
| Corrosion Investigations | Investigates the cause of insufficient cathodic protection levels or other issues and recommends mitigating solutions. |
| Enhanced Cathodic Protection Resurvey | Evaluates cathodic protection area boundaries and protection status and updates documentation to ensure that Cathodic Protection systems are operating properly. |
| Electrical Interference – AC | Mitigates the threat of alternating current interference with investigative modeling and installation of grounding and/or shielding equipment. |
| Electrical Interference – DC | Addresses the risk of direct current interference with investigation and installation of Cathodic Protection, bonding, or other equipment. |
| Internal Corrosion | Monitors for and mitigates the threat of Internal Corrosion in gas pipelines. |
| Routine Maintenance | Pipeline safety regulations require PG&E to conduct rectifier checks; pipe-to-soil, casing-to-soil, and other reads; and atmospheric corrosion inspections on a regular basis. |
| Test Stations | Installs or replaces test stations in areas along the piping system where cathodic protection monitoring is required. |

PG&E continues to advance its goal of building a best-in-class corrosion control program by incorporating industry corrosion control standards, peer operator experience, third-party evaluations, and corrosion research into its standards and procedures. PG&E actively participates in corrosion research conducted by the Pipeline Research Council International (PRCI) and supports efforts to incorporate the results of such research into corrosion control regulations and standards through its participation in National Association of Corrosion Engineers (NACE) International, the Interstate Natural Gas Association of America (INGAA), and the American Gas Association (AGA).

### i) Earthquake Fault Crossings

PG&E's Fault Crossings Program addresses the specific threat of land movement at active earthquake faults that subject a pipeline to external loads due to seismic events. The program is

consistent with California law that requires natural gas operators to prepare for and minimize damage to pipelines from earthquakes. PG&E performs system-wide studies to address both the anticipated geologic movement and pipeline mechanical properties to manage the integrity of the pipe (Table 20). Additional mitigation work is then prioritized, following each study, by considering the likelihood of failure (the probability that the fault will trigger a seismic event), and the consequences of failure (including the impact on the local population, PG&E system reliability, and the environment). Mitigation typically includes modified trench designs, trench adjustment, pipe replacement, or installation of automated isolation valves.

**Table 20 – Earthquake Fault Crossing Program**

| | Studies[e] | Crossings Mitigated[f] |
|---|---|---|
| **Pre-2015** | 52 | 24 |
| **2015** | 65 | 18[a] |
| **2016** | 65 | 6[b] |
| **2017** | 22 | 7[c] |
| **2018** | 34[g] | 25[d] |

(a) 2015 – 14 crossings were FFS per current design. 4 crossings replaced.

(b) 2016 – 3 crossings were FFS per current design. 3 crossings replaced.

(c) 2017 – 5 crossings were FFS per current design. 2 crossings replaced

(d) 2018-20 crossings were FFS per current design and 2 were considered mitigated by existing Valve Automation. 3 crossings were replaced.

(e) Studies are conducted to determine if pipe is fit FFS with geological, pipe assessments.

(f) Crossing is mitigated if pipe meets or is designed, retrofitted, or replaced to satisfy the FFS criteria.

(g) The difference between this report and PG&E's Transmission Pipeline Compliance Report 2019-01 submitted on January 30, 2019 is timing of data confirmation.


**Figure 34 – Pipeline 2402-01 Replacement Crossing the Hayward Fault in Downtown Hayward in August 2018**

## j) Leak Survey

Pipeline safety regulations require PG&E to conduct routine leak surveys on its gas system to find gas leaks. The frequency of the leak surveys depends on the type of facility, operating pressure, and class location of the pipe.

PG&E outlines current requirements, standards, and guidelines for the Leak Survey and Detection Program in its procedures. In 2018, PG&E surveyed over one million gas distribution pipeline services, over 13,000 gas transmission pipeline miles, and performed daily leak surveys on 115 wells in compliance with DOGGR's emergency gas storage regulations. In addition, PG&E performed quarterly surveys in compliance with California Air Resources Board (CARB) regulations at PG&E's gas storage facilities and

compressor stations. PG&E conducts leak surveys on more assets today because CPUC's General Order (GO) 112F changed the survey frequency for some gas transmission pipelines.

In 2015, PG&E implemented the use of an advanced leak detection technology, Picarro Surveyor, into a standard leak management operating model. Since 2017, PG&E's operating model is being used in each division as a standalone process. This has created additional efficiencies and lower overall cost to the Company. Using this model, we have been able to complete our compliance survey in a more timely fashion. The second step in the model's process is to immediately repair all hazardous leaks identified during the survey and to schedule for repair all identified leaks that meet the schedulable leak criteria. Finally, PG&E bundles the scheduled leak repair job packages allowing a more efficient and effective repair strategy. PG&E continued this process in 2018 and met 75 percent of its 3-year distribution system compliance survey requirements using its local Picarro approach. All repairs were made by local crews through the use of the same bundle approach used in the standard operating model.

PG&E transitioned from a 4-year survey cycle in 2017, to a 3-year survey in 2018 as a result of Best Practice 15 in the Leak Abatement Order Instituting Rulemaking (OIR) decision.[30] PG&E will continue its expanded use of the Picarro technology in all of its divisions, completing at least 75 percent[31] of its gas distribution compliance survey. The expanded use of the Picarro technology and the acceleration of leak survey cycle will continue to support PG&E in its ability to: (1) find and fix more leaks, thereby eliminating more potential hazards to the public; (2) significantly reduce the number of Grade 2 open leaks present on the system at any time (the leaks that occur between surveys); and (3) reduce greenhouse gas (GHG) emissions.

In addition, in 2018, PG&E began the Super Emitter survey across the entire distribution service territory in response to the Leak Abatement OIR, Best Practice 21. PG&E defines a Super Emitter leak as one that emits more than 10 standard cubic feet per hour of methane. As a result, in 2018, PG&E completed the Super Emitter survey on 85 percent of its gas distribution services. The purpose of this survey is for Picarro to identify and measure the leak flow rates of super emitters as they are found during compliance survey. The data will then inform PG&E of the prevalence of these leaks and the emission reduction that can be gained by repairing them quickly. In 2019, PG&E will continue the Super Emitter survey across the entire system.

To further enhance its distribution Leak Survey process, initiatives are in progress to continue to support PG&E's transition to a 3-year leak survey cycle, including implementing technology to enable an end-to-end paperless leak survey process, and integration with enterprise systems.

Summaries of PG&E's 2018 Leak Survey cycles for its distribution and transmission pipeline systems are shown in Table 21 below:

| Table 21 – Leak Survey Frequency | | |
|---|---|---|
| **Facility Types** | | **Survey Frequency** |
| All Company facilities w/in business districts and public buildings | Distribution (MAOP <60 psig) | Annual |
| Buried metallic facilities not under Cathodic Protection and not covered by an annual requirement | | 3 years |
| Balance of underground distribution facilities | | 3 years |
| Department of Transportation All Odorized Transmission | Transmission (MAOP > 60 psig) | Semi-Annual |
| Gathering: Class 1, 2, 3 and 4 | Transmission (MAOP > 60 psig) | Semi-Annual |
| Stations: Class 1, 2, 3, and 4 | Transmission (MAOP > 60 psig) | Semi-Annual |
| Perimeter of Enclosed Electric Substations and Switching Stations | | Every 6 months |
| Wellhead, attached pipelines, and surrounding area in 100-ft radius | Gas Storage | Daily |
| Method 21 on all above ground components at 3 Underground Storage Facilities and 9 Compressor Stations | Gas Storage and Compressors | Quarterly |

## k) Leak Repair

Pipeline safety regulations and guidelines require PG&E to repair certain leaks. In 2018, PG&E's trained and operator-qualified personnel classified leaks into three grades (Grade 1, 2, and 3)[32] based on the severity and location of the leak, the risk the leak presents to persons or property, and the likelihood that the leak will become more serious within a specified amount of time. PG&E's leak grading practices for Grade 3 leaks exceed industry guidance, as set by the American Society of Mechanical Engineers (ASME) Gas Piping Technology Committee Guide for Gas Transmission and Distribution (T&D) Piping systems.[33] PG&E also repairs, rather than rechecks, above-ground Grade 3 leaks on its distribution system, and has begun repairing all Grade 3 leaks on its transmission system within 12 months of discovery in accordance with the CPUC's GO 112F. In 2018, PG&E repaired 2,017 below-ground Grade 3 distribution leaks to further reduce GHG emissions and in response to the Leak Abatement OIR, Best Practice 21. Best Practice 21 requires that PG&E repairs all leaks within a maximum of three years after discovery, within reasonable conditions or costs, to eliminate the backlog of leaks.

In 2018, PG&E used its continuous improvement approach to more efficiently bundle and schedule leak repairs. Having all the work required in an area at one time provides opportunity to bundle work locations and effectively maximize the utilization of resources. In 2018, PG&E repaired over 41,000 gradable leaks on the gas distribution and transmission system. Those repairs aided PG&E in maintaining a low open leak inventory of 239 Grade 2 leaks at the end of the year.

Figure 35 – PG&E's Maintenance & Construction Crew at Work

PG&E continues to review and improve its standards, procedures, field processes and equipment to further reduce the public safety risk of and the emissions from gas leaks.

## l) Overpressure Elimination Initiative

A pipeline that operates at higher than the MAOP presents an operational risk to the safety of the public, employees, and contractors working on the facilities. When a pipeline operates above its MAOP, it is known as an abnormal operating condition and is described as an overpressurization (OP) event. OP events have the potential to overstress pipelines and may lead to loss of containment. Large OP events (see Figure 36) pose significant safety and operational impacts to PG&E's gas system. In 2012, PG&E began an initiative to eliminate system OP events and reduce operational risk. In 2016, PG&E identified human performance and equipment failure as the two most common causes for OP events. Actions to eliminate OP events were implemented including: station design and construction best practices; lock-out/tag-out process improvements; distribution of information around associated OP risk factors through training and communication initiatives.

**PG&E's overpressure management achieves top quartile results among benchmarked domestic pipelines.**

In 2017, the focus on corrective actions was again directed at human performance and equipment failure. Human performance training was rolled out to PG&E's Gas leadership, with communication targeted at sharing OP elimination strategies. PG&E continued to install Supervisory Control and Data Acquisition (SCADA) points to increase system real-time visibility in the Gas Control Center (GCC); along with installing sulfur filters on pilot-operated equipment. An extensive benchmarking effort with European operators plus a review of European regulations led to the development of a strategy that supports the goal to eliminate OP events with the deployment of a secondary overpressure protection device under certain conditions. Large Volume Customer primary regulation sets also received accelerated inspections.

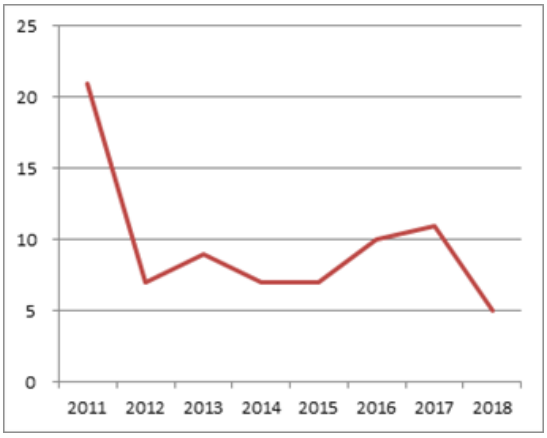



Figure 36 – Large OP Events

In 2018, PG&E began its strategy to install secondary over pressure protection devices on our pilot-operated regulation equipment. PG&E has a strategic goal of installing secondary overpressure protection devices at 50 percent of our pilot-operated sites by the end of 2022. The reasons why pilot-operated regulation equipment is particularly vulnerable to large overpressure events are twofold: (1) they can fail due to gas quality issues, such as debris, sulfur, liquids, or black powder; and (2) they

tend to have a design that causes both the regulator and the monitor to fail in an open position, therefore resulting in a loss of regulation.

PG&E currently has 1,511 distribution pilot-operated stations and 292 transmission pilot-operated stations. At the end of 2018, PG&E had a total of 237 pilot-operated stations in which a secondary overpressure protection device has been installed.

At the end of 2018, the National Transportation Safety Board (NTSB) published a Safety Recommendation Report in response to a September 2018 overpressure event in Merrimack Valley, Massachusetts, also known as the Merrimack event. The recommendations in the NTSB report focused on the specific causes of this event, including implementation of professional engineering review, record completeness, management of change process, and additional control procedures during operations. For PG&E's low-pressure systems, the approach to reduce the likelihood of a Merrimack-type event and other reasonable possible drivers of an overpressure event is to augment code-required pressure control and overpressure protection devices (first layer) with a slam-shut (second layer) that is activated by high and low pressure, supplemented by a third layer of overpressure protection. PG&E's view is that overpressure events can be caused by several different drivers, which can include design-related issues similar to the Merrimack event, equipment-related causes, construction activities, third-party damage, and human performance issues during maintenance. PG&E's strategy is to protect our asset and operations against all possible modes of failure.

PG&E continues to modify operations and upgrade gas system regulation equipment to provide greater separation between normal operating pressures and the MAOP. Each activity builds on the goal to eliminate OP events, thereby contributing to system safety.

### m) Community Pipeline Safety Initiative

The shareholder-funded Community Pipeline Safety Initiative focused on enhancing safety and reducing risk to PG&E's gas transmission pipelines. The program involves working collaboratively with more than 12,000 customers in more than 380 communities to check the area above PG&E's 6,750 miles[34] of gas transmission pipeline. When structures and vegetation are located too close to the pipeline, they can delay critical access for first responders and safety crews or threaten the integrity of the pipeline. The program was initially anticipated as a five-year initiative ending in December 2017 but has been extended through December 2019 due to long-lead permitting and the amount of time it has taken to reach agreements with some customers and municipalities. The final 27 miles of vegetation clearing is expected to be completed in 2019.

This safety program began with a comprehensive centerline survey completed in December 2013 that allowed PG&E to precisely locate and monitor its gas transmission pipelines and input the data into

a new Geographic Information System (GIS). Efforts to date have also included replacing damaged or aging pipeline markers and, in some cases, installing new markers throughout PG&E's service area. The markers observations have evolved to be an ongoing markers maintenance program under Gas Transmission patrols. The remaining Community Pipeline Safety Initiative projects are listed below:

- **Structure Projects** – The program team is working with local municipalities and commercial and residential private property owners to address 360 miles of structures that are located within PG&E right-of-ways and could interfere with access to the pipeline and its ongoing safe operation. When a structure is identified in the pipeline ROW, PG&E works with the local jurisdiction or property owner to remove and/or relocate the structure outside of the ROW and away from the pipeline.
- **Vegetation Projects** – The program team is working with cities, counties and private property owners to clear 1,553 miles of vegetation (trees and brush) from the area above the transmission pipeline that could impede access in an emergency or for critical maintenance work or cause potential damage to the pipe. When trees are located too close to the gas pipeline, they can also interfere with PG&E's ability to monitor the area and ensure the pipeline is operating safely. In addition, the presence of tree roots can adversely affect the risk profile of the pipeline as it relates to susceptibility to external corrosion and structural damage to the pipeline due to tree movement caused by weather related and outside force events (e.g., high winds, unstable soil, lightning, heavy rains, seismic). There is also a greater likelihood of third parties digging into the pipeline and causing damage if the pipeline area is not clearly visible. PG&E offers tree replacements and restoration for any trees that need to be removed for safety reasons.

Since the Community Pipeline Safety Initiative began in 2013, PG&E has cleared a total of 359.5 structure miles and 1,526 vegetation miles, improving the overall safety and reliability of the gas transmission system. Going forward, PG&E is committed to continuing to work with customers to keep the area around the gas pipeline safe and clear, as part of our ongoing pipeline O&M.

Vegetation Miles Addressed

| | Act + Fcst | Cumulative % | Complete |
|---|---|---|---|
| 2013 | 115 | 7% | 115 |
| 2014 | 146 | 17% | 146 |
| 2015 | 380 | 41% | 380 |
| 2016 | 540 | 76% | 540 |
| 2017 | 258 | 93% | 258 |
| 2018 | 87 | 98% | 87 |
| 2019 | 27 | 100% | |
| Total | 1,553 | | 1,526 |

As of 12/31/18, approx. 98% of vegetation miles have been addressed (1526/1553)

Structure Miles Addressed

| | Act + Fcst | Cumulative % | Complete |
|---|---|---|---|
| 2013 | 5 | 1% | 5 |
| 2014 | 110 | 32% | 110 |
| 2015 | 93 | 58% | 93 |
| 2016 | 114 | 90% | 114 |
| 2017 | 30 | 98% | 30 |
| 2018 | 7.5 | 99% | 7.5 |
| 2019 | 0.5 | 100% | |
| Total | 360 | | 359.5 |

As of 12/31/18, approx. 98% of structure miles have been addressed (359.5/360)

**Figure 37 – Overall Community Pipeline Safety Initiative Program Metrics (2013-2018)**

## 6. Mitigating the Risk of Loss of Supply

In 2018, PG&E transported and delivered about 982 billion cubic feet of gas.[35] PG&E works year-round to assure system reliability through its management of system pressure, capacity, monitoring, and controls. The following sections discuss PG&E's programs designed to mitigate the risk of losing gas supply.

### a) System Pressure and Capacity

PG&E designs and operates its gas system to ensure safe pressure regulation and adequate gas supplies. PG&E continuously monitors the pressure of its system [see Section IV.7.a *Gas System Operations and Control*]. Additionally, PG&E measures and works to reduce overpressure incidents. PG&E's gas systems are designed to meet all expected core demands (residential and small commercial customers), with non-core demand (large commercial, industrial, or institutional customers) assumed fully curtailed, at a design temperature that is the coldest temperature that may be reached once in every 90 years (referred to as an Abnormal Peak Day, or APD). Also, PG&E's gas systems are designed to meet all expected demand, core and non-core, at the coldest temperature that may be reached once in every two years (referred to as a Cold Winter Day, or CWD).

PG&E's gas system was successfully tested in real-time in December 2013, when it experienced two days below the one-day-in-two-year CWD standard. Sacramento experienced temperatures below the Cold Winter Day criteria for five consecutive days. However, PG&E was able to provide continuous gas service to all core customers and, consistent with system planning, requested curtailments of up to 61 non-core customers, whose rate agreement includes a curtailment provision.

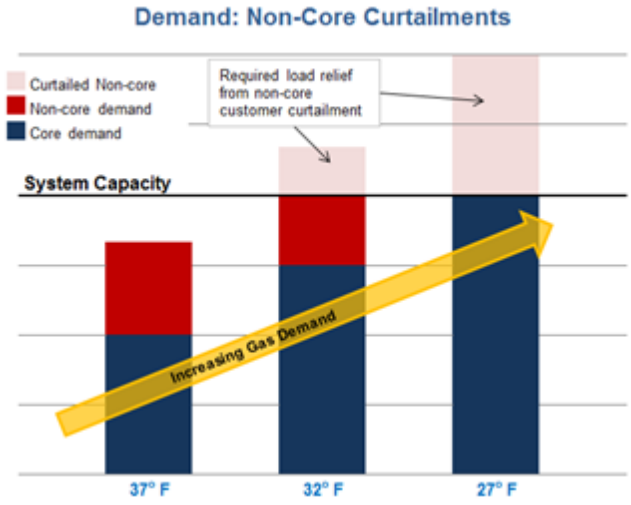



Figure 38 – How Demand for Gas Affects Capacity

Insufficient capacity can result in reliability issues that pose significant public health and safety risks. For instance, a lack of pipeline capacity could lead to a loss of gas service that customers depend on for daily life activities including space heating, water heating, and cooking. In very cold weather, loss of space heating can itself be life-threatening and can prompt customers to use unsafe heating alternatives. Loss of gas service can also lead to extinguished pilots and the subsequent potential for uncombusted gas entering affected buildings. In some scenarios, loss of gas service due to insufficient local pipeline capacity could affect electric generation, which could also result in health and safety concerns.

PG&E drives the quality of its planning effort through a matrix of tools, processes, personnel, standards, internal and external data, and documentation that provides the appropriate level of oversight and control to its management team.

| Gas System Planning | Network Investment Plan | 2018 |
|---|---|---|
| Obtains information from a variety of sources to determine possible load growth and other potential changes that may affect system capacity requirements. In addition, systems are studied as needed to ensure that planned pipeline operations are managed for minimum impact on capacity. | A multi-year program that analyzes PG&E's gas systems to optimize system design. The objective is to efficiently incorporate various safety-related pipeline efforts into design work driven by other factors. This effort is intended to identify and correct design inefficiencies. | **In 2018, PG&E completed or updated 21 network investment plans.**<br>• 1 Local Transmission<br>• 18 Distribution<br>• 2 Combined Local T&D systems |

Figure 39 – Gas System Planning

## b) Operations Clearance Procedure

An important part of public and employee safety is the use of the Gas Clearance procedure. The Clearance procedure provides an added safety step or layer of protection to confirm that a plan and procedure to protect employee and public safety is in place before work is performed on the gas system. The Clearance Procedure is used for all work that impacts gas flows, pressures, remote monitoring and control, or gas quality. All clearances are approved by Gas Control.

In 2018, the Operational Change (OC) Documentation process leveraged the clearance process to collect critical documents. Timely updates to our systems of record, based on documentation of work

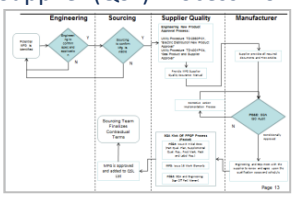
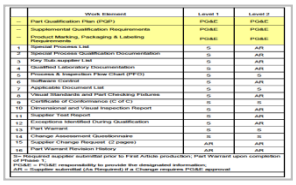
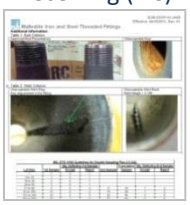
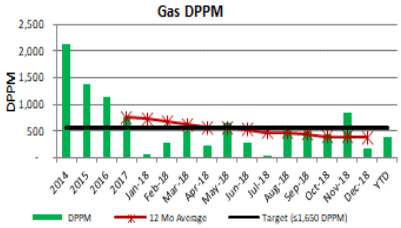
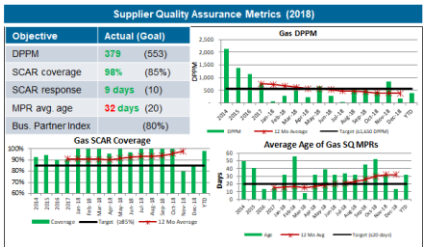
completed in the field, is critical to safety of PG&E personnel and customers. The as-built process is our vehicle for gathering complete documentation of work. The OC Documentation Process was designed by Asset Knowledge Management and the GCC to collect critical as-built documents soon after gas containing assets are made operational, making it possible to update safety and compliance-critical information early in the as-built process. The GCC uses this information to direct clearances for work. Finally, our maintenance departments use the information to perform maintenance per regulation to ensure the integrity of our systems.

Gas Control creates clearances to help manage safety risk during work performed by field personnel. By incorporating the OC Documentation Process into the clearance process, clearances now can also be used for collecting documents about other safety and compliance-related work that has just happened.

### c) Supplier Quality Assurance (SQA) for Distribution and Transmission

The SQA organization is responsible for assuring the safety and quality of material provided by PG&E's suppliers. If non-conforming material is purchased to be used in pressurized gas systems it might introduce a safety risk to employees, the public, and to the gas infrastructure.

PG&E's SQA group collaborates with engineering, construction, and supply chain to create rigorous standards for incoming material and assures that qualified suppliers provide material that meets PG&E's product qualification requirements. While the process for materials and suppliers for gas distribution and transmission are adapted to the unique needs of the business, Figure 40 illustrates the general SQA process. Using this process, SQA has reduced an overall 50 percent year over year in Defective Parts Per Million (DPPM) to 379. The DPPM target for 2019 is 284.

| 1. Qualification | 2. Material Inspection | 3. Material Problem Reports |
|---|---|---|
| Supplier (QSL) Process Flow<br>  <br>Product Qualification (PPQP)<br>  | Receiving (DC)<br>  <br>Source (Supplier)<br>  | Material Problem Reports (MPR)<br>  <br>*[See Section II.1.c *Material Problem Reporting]* for more detail on the Material Problem Reporting process. |
| **4. Supplier Corrective Action** | **5. Defective Parts per Million** | **6. Supplier Feedback** |
| SCAR[(a)] / Failure Analysis<br>  | Defective Parts Per Million<br>  | Supplier Scorecard<br>  |

(a) Source: PG&E Corporation Supplier Corrective Action Request.

**Figure 40 – How PG&E Manages Suppliers**

SQA achieved industry best-in-class performance since 2013 for quality programs driving supplied material to be 99.96 percent defect free. Eighty seven percent of PG&E's supply base has achieved third-party ISO 9001 certification of their Quality Management System (QMS). SQA was re-certified to ISO 9001:2015 QMS and had zero non-conformities for all four audits. Through PG&E's cross functional teams and supplier partners, SQA processed 288 Supplier Change Requests and three supplier material recalls. In addition, SQA initiated an annual supplier survey to identify improvement opportunities. A 90 percent approval score showed the areas of opportunity as SQA works toward 100 percent.

## 7. Mitigating the Risk of Inadequate Response and Recovery

In addition to the programs that PG&E has in place to mitigate the risk of loss of containment and loss of supply, PG&E is prepared to respond to and recover from incidents. PG&E's policies and procedures have been revised to provide effective system controls for both equipment and personnel to limit damage from accidents, explosions, fires and dangerous conditions. It is PG&E's policy to:

- Plan for natural and manmade emergencies such as fires, floods, storms, earthquakes, cyber disruptions, and terrorist incidents;

- Respond rapidly and effectively, consistent with the National Incident Management System principles, including the use of the Incident Command System, to protect the public and to restore essential utility service following such emergencies;
- Help alleviate emergency related hardships; and
- Assist communities to return to normal activity.

All PG&E emergency planning and response activities are governed by the following priorities:

- Protect the health and welfare of the public, PG&E responders, and others;
- Protect the property of the public, PG&E, and others;
- Restore gas and electric service and power generation;
- Restore critical business functions and move towards business as usual; and
- Inform customers, governmental agencies and representatives, the news media, and other constituencies.

| Objective | Description |
|---|---|
| **Establish Command** | Determine the Incident Commander, set up an Incident Command Post (ICP), activate Emergency Center(s), if necessary |
| **Assess Situation** | Gather information about emergency, assess the situation in coordination with appropriate 911 agency(ies) and PG&E Gas Control Center |
| **Make Safe** | Make area safe for public, employees and others |
| **Communicate/Notify** | Communicate to/notify the appropriate PG&E personnel, regulatory agencies, public agencies such as fire, police, city and county emergency operations, GCC, customers and media |
| **Restore** | Restore gas service |
| **Recover** | Deactivate ICP and/or Emergency Centers and return to business as usual |

**Figure 41 – Key Incident Response Objectives**

PG&E uses the structure of the Incident Command System to complete key steps in responding to incidents. The key incident response objectives in Figure 41 represent a typical process flow through the cycle of an incident. However, incidents may not necessarily follow this exact sequence. For example, it may be appropriate to "Make Safe" at several points during the response process and not just after "Assess the Situation."

The next section discusses programs in place to mitigate threats to enable PG&E to respond in a timely manner.

## a) Gas System Operations and Control

PG&E's Gas Control Center (GCC) monitors and controls the flow of gas across PG&E's system 24 hours a day, 365 days per year, so that natural gas is received and delivered safely and reliably to customers. The GCC provides near instantaneous visibility on the gas system. This allows PG&E to prevent, quickly react to, and mitigate issues that may pose a safety risk to the public and PG&E employees.

| | | | | |
|---|---|---|---|---|
| Transmission | 18.3K<br>Transmission SCADA points | 100%<br>Visibility into Transmission system Backbone | 55%<br>Visibility into Transmission local transmission[(a)] | 107<br>Transmission Devices installed 2011-2018 |
| Distribution | 21.7K<br>Distribution SCADA points | 60%<br>Visibility into Distribution system | | 1,442<br>Distribution Devices installed 2011-2018 |

(a) This value is down from last year's report due to a change in the source data for the total number of gas transmission stations.

**Figure 42 – PG&E's Progress in Enhancing System Visibility Through SCADA**


**Figure 43 – PG&E's Gas Control Center Features a 90 Foot-Long Video Wall With Current Operational Information to Augment The Gas SCADA System**

PG&E's Gas Transmission Control Center, Gas Distribution Control Center, and Gas Dispatch functions are co-located in a single facility. The co-location of these three functions enables the company to better communicate, share information, and monitor the systems to provide superior emergency response coordination. This visibility, monitoring, control, and response capability is important to PG&E's Gas Safety Excellence vision. For the GCC to be effective, a key control need is situational awareness—the ability to identify, process, and comprehend the critical elements of information about what is happening. Billions of data records, composed of a mix of near real-time gas system operational data and a variety of geospatial, time dependent, and historical information that relates to the gas system provide critical information to Gas Control to aid in decision-making. This data interacts with alarms to focus the operators' attention on abnormal situations. They are also bundled to display clear information to operators so they can quickly assess a developing issue.

## b) Cyber Security

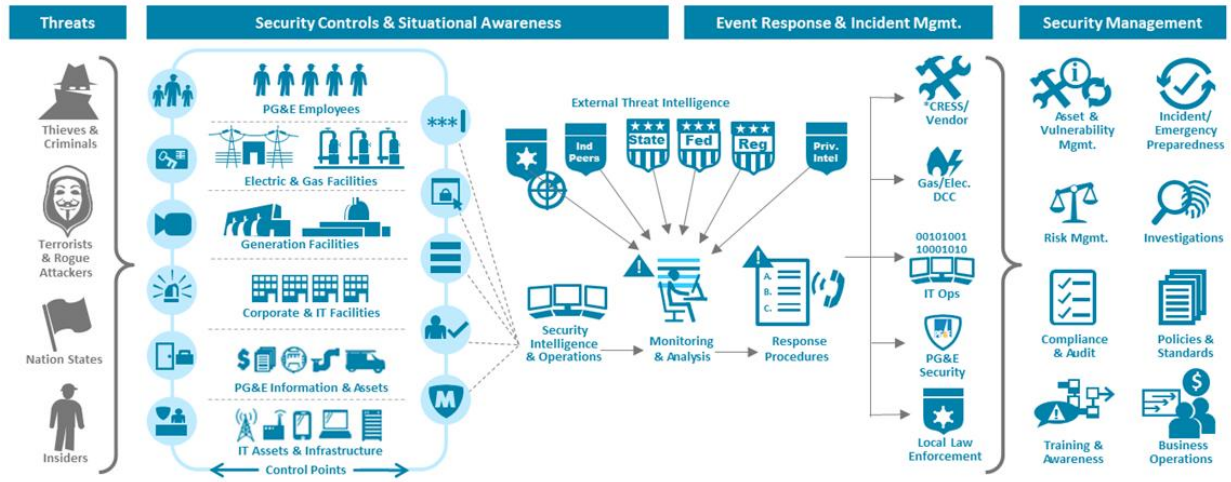
PG&E's commitment to security directly contributes to our mission to deliver safe, reliable, affordable and clean energy. PG&E's natural gas operations incorporate significant risk management activities, including those that address cyber-attack threats. PG&E's Cybersecurity organization advises Gas Operations on cybersecurity risk remediation and mitigation activities to protect information and operational technology, with a focus on control systems. PG&E's gas control systems are considered critical digital assets, and therefore require protection through continual control and mitigation improvements. Control and mitigation investments are reviewed and updated on an annual basis.

PG&E Cybersecurity's mission is to deliver and maintain an integrated program to safeguard PG&E digital assets by:

- Identifying cybersecurity risks and defining mitigating strategies
- Building, deploying, and operating effective security technologies and processes
- Proactively monitoring for and responding to cyber-threats
- Collaborating with public and private entities to drive standards and best practices

Figure 44 – Examples of Active PG&E Government Partners

PG&E's Security Program (which includes both cyber and physical security aspects) effectively manages cybersecurity risks and proactively adapts to evolving threats and changing business needs. The Security Program, based on industry best practices, is designed to enable informed risk decision making necessary to support the safe, reliable, affordable, and clean delivery of energy to customers.




* CRESS is Corporate Real Estate Strategy and Service

**Figure 45 – PG&E Unified Cyber/Physical Security Program Effectively Manages Risk and Proactively Adapts to Evolving Threats and Changing Business Needs**

PG&E uses industry best practices, such as the National Institute of Standards and Technology Cybersecurity Framework, to ensure Cybersecurity controls and mitigations are suitably robust to identify, protect, detect, respond, and recover from cyber-attacks.

The PG&E Security Program also applies a defense-in-depth strategy with layered controls, so assets are deployed with multiple protections at each layer of the technology stack (network, application, endpoint, application, and data).

Given continual cybersecurity threats and the evolving sophistication of adversary attacks, PG&E's Security Program is regularly assessed to validate strategic direction and improve alignment with current industry best practices. Assessments can occur through participation in cybersecurity events, such as the 2018 PG&E Cybersecurity Exercise. This exercise consisted of three parts: (1) a simulated cyber-attack by a foreign nation state targeting industrial control systems and corporate enterprise networks, enabled by PG&E insiders; (2) an executive table top discussion of key strategic issues to consider in the wake of a catastrophic cyber-attack; and (3) an external roundtable to spark dialog between company executives, senior industry partners and federal, state, and local officials. It is through the results of cybersecurity exercises that PG&E is better able to identify and plan control improvements that strengthen Gas Safety.

In addition, in 2018, PG&E participated in a voluntary assessment to have PG&E's Security Architecture reviewed by the Federal Energy Regulatory Commission (FERC) and the Department of Homeland Security Transportation Security Administration (DHS-TSA). The purpose of the review was to gain a comprehensive understanding of PG&E's overall cybersecurity posture, to identify potential areas of concern, and to articulate actionable recommendations and observations for positive change.

PG&E also has a Security Awareness and Training Program which is an enterprise security communication strategy focused on maintaining and strengthening PG&E's security culture. Regular security communications instruct employees to keep the Company's assets and information secure. The PG&E Security Awareness and Training Program communicates security best practices, tips, and risks, and helps employees understand the importance of protecting PG&E information and assets. One component of the Security Awareness and Training Program enlists the enterprise-wide workforce to help socialize standards and act as early adopters and leaders for security improvements. The Security Awareness and Training Program integrates security awareness into PG&E's culture, establishes employee engagement themes developed based on security assessments and threat intelligence information, and ultimately reduces security risk.

Protecting PG&E from ever-changing cybersecurity threats landscape enables us to conduct our work in a secure manner that protects our customers, employees, and assets.

### c) Valve Automation

PG&E's Valve Automation Program is designed to accelerate emergency response and minimize the time of exposure in the event of an unintended release of gas. The Valve Automation Program allows certain gas transmission pipelines to be rapidly isolated through remote and automatic control valve technology. Installation of automated isolation capabilities on transmission pipelines in populated areas may reduce property damage and danger to emergency personnel and the public in the event of a pipeline rupture. PG&E's control room personnel have received training to develop a "bias for action." This training helps them recognize and act on system conditions warranting immediate isolation of pipeline systems and planned SCADA installations to continue to increase system visibility are ongoing [see Section IV.7.a. *Gas System Operations and Control*].

The Valve Automation Program builds upon the scope and principles in PG&E's Pipeline Safety Enhancement Plan that replaced, automated, and upgraded gas shut-off valves across PG&E's gas transmission system starting in 2011. In 2018, an additional 46 valves were automated through the Valve Automation Program. In the 2019 GT&S Rate Case, PG&E proposed automating 80 valves between 2019 and 2021.

**Figure 46 – A Complicated Valve Completed in 2018**

| Table 22 – Valves Automated | | | | |
|---|---|---|---|---|
| | PSEP | 2015 GT&S Rate Case | | Total (PSEP and 2015 GT&S Rate Case) |
| | | 2015-2017 | 2018 | |
| Valve Automation (units) | 217 | 74 | 46 | **337** |

## d) Emergency Preparedness and Response

PG&E's Gas Emergency Response practice is documented primarily in the Gas System Operations Control Room Management Manual and the Gas Emergency Response Plan (GERP). For changes to PG&E's GERP, please see Attachment 4.

### i. Gas System Operations Control Room Management Manual

Gas Control is responsible for the overall operation of PG&E's gas system, and therefore closely monitors and coordinates emergency notifications, dispatching, system isolations, and restorations.

Gas Control personnel primarily use SCADA system data to monitor and control critical assets remotely. The SCADA system alerts Gas Control of gas system irregularities via alarms. When these alarms go off, Gas Control can immediately initiate and execute shutdown zone plans or direct field personnel to respond to critical locations for the execution of manual valve operations. In addition, Gas Control notifies appropriate 911 agencies and departments within PG&E so that emergency response resources are informed and dispatched.

To maintain compliance and aid in the management of abnormal and/or emergency operating conditions, PG&E regularly trains gas control personnel on the Gas System Operations Control Room Management Manual. For changes to PG&E's Gas System Operations Control Room Management Manual, please see Attachment 4.

### ii. Company Emergency Response Plan

The purpose of the Company Emergency Response Plan (CERP) is to assist the gas and electric businesses with a safe, efficient, and coordinated response to an emergency. For changes to PG&E's CERP, please see Attachment 4.

The CERP provides a broad outline of PG&E's organizational structure and describes the activities undertaken in response to emergency situations. The CERP presents a response structure with clear roles and responsibilities and identifies coordination efforts with outside organizations (government, media, other gas and electric utilities, essential community services, vendors, public agencies, first responders, and contractors).

The CERP follows a logical flow from general emergency response concepts and guidelines to specific emergency management organizational structure, roles, responsibilities, and processes. When appropriate, the plan also references supporting procedures and other response materials.

In addition, PG&E maintains business continuity plans, which describe how PG&E will continue its critical business processes in the event of a disruption to facilities, technology or personnel.

### iii. Gas Emergency Response Plan

The GERP[36] provides detailed information about PG&E's response to gas emergencies. It supports the response to all emergencies broadly as "One PG&E" through the integration with the CERP and the other LOB emergency response plans, which are annexes to the CERP.

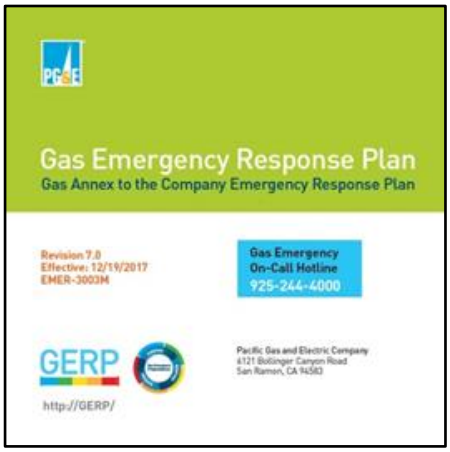



**Figure 47 – The Gas Emergency Response Plan as of Dec. 31, 2018**

The GERP provides an outline of the Gas Operations organizational structure and describes the activities undertaken in response to incidents. It provides a response structure with clear roles and responsibilities, a communication framework, and identifies coordination and response integration efforts with outside organizations and community first responder agencies.

The GERP outlines gas specific criteria to PG&E's Incident Levels that are provided in the CERP. The Incident Levels categorize and support PG&E in understanding the complexity of an incident and the actions that may be employed at each level (e.g., emergency center activations, resources requests, etc.). To ensure a consistent and well-coordinated response to emergencies, the Company has adopted the following incident classification system:

- Incident Level 1 – Routine
- Incident Level 2 – Elevated
- Incident Level 3 – Serious
- Incident Level 4 – Severe
- Incident Level 5 – Catastrophic

### iv. Gas Emergency Preparedness Team

The Gas Emergency Preparedness Team assists Gas Operations with emergency planning, preparedness, response, and review. This group maintains the GERP, leads exercises, facilitates after action reviews, and participates in industry activities designed to impart best practices. The group facilitates the use of the Incident Command System, a systematic, proactive approach for all levels of governmental and non-governmental organizations and the private sector to work together during an

incident to reduce the loss of life, damage to property and harm to the environment. Further, the team supports the Gas organization's local emergency centers, called Operations Emergency Centers, and the Gas Emergency Center, which is co-located with the GCC. These centers are activated according to criteria outlined in PG&E's GERP.

**Throughout 2018, the Gas Emergency Preparedness Group:**

- Conducted 54 instructor led trainings
- Facilitated 8 Operations Emergency Center exercises
- Facilitated 1 Gas Emergency Center exercise (which included senior leadership participation in command and general staff Incident Command System roles)
- Supported the response to 10 emergency activations requiring activation of the local operations emergency center

Frequent outreach to first responders helps strengthen how PG&E coordinates when emergencies happen. In 2018, Public Safety Emergency Preparedness completed the following efforts in partnership and close coordination with first responders and local governments:

**Figure 48 – Delivered 455 First Responder Workshops to more than 8,000 first responders. These workshops train First Responders to safely respond to gas and electric emergencies and exactly how to access the PG&E gas transmission pipeline mapping system.**

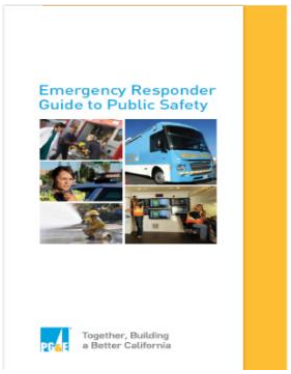



**Figure 50 – Hosted two Public Safety Liaison Meetings across the service territory to share PG&E's emergency response plans. Representatives from federal, state, county and city governmental agencies attended these meetings.**

**Figure 49 – Met with the 373 fire departments responding to gas incidents. These meetings focused on contingency plans in the event of an emergency.**


**Figure 51 – Public Safety Emergency Preparedness attended and presented Public Safety materials for both gas and electric at 18 Safety Fairs and Conferences reaching over 3,700 people, including first responders and the public.**

Figure 53 – Supported 276 811 Dig-In Reduction and safety-related activities in collaboration with the Damage Prevention team to improve safety within PG&E's communities and reduce the incidents of third party dig-ins.

Figure 52 – Supported over 100 incident response activities (including dig-ins). Public Safety Emergency Preparedness acted as an Agency Representative between PG&E and the first responder community.


# V. Workforce Safety

PG&E's work requires well-trained personnel to correctly perform work activities. As a result, the Company invests in recruiting and retaining, provides ongoing development and training, and maintains supportive controls for employee and contractor work.

For example, employees are required to don the appropriate Personal Protective Equipment (PPE) when they are in the field. Employees can refer to PG&E's PPE Matrix which documents the minimum PPE required when performing a certain task. PG&E annually reviews its PPE Matrix to evaluate the appropriateness of current PPE requirements. Employees in the field also document the controls for any identified hazards associated with their tasks using a Job Site Safety Analysis (JSSA) form. In 2018, PG&E revised the Job Site Safety Analysis (JSSA) document to include SIF checklists and additional guidance for control measures. PG&E's PPE Matrix and JSSA are vital resources for employees as they plan their work prior to executing in the field.

PG&E believes that well-trained, fully-engaged employees are a key component of Gas Safety Excellence.

## 1. Workforce Size

PG&E's internal employee workforce works in conjunction with qualified contractors to perform quality work and maintain the safety of PG&E's gas system. Gas Operations engages the Workforce

Planning function and Human Resources partners to determine the appropriate workforce size and types of roles that are required to fulfill our annual work objectives. We recruit qualified and talented employees and, at times, rely on the unique capabilities of various contracting firms during periods of peak or unique workload. PG&E has robust training programs and training facilities to develop its workforce so each of our employees has the knowledge to perform his or her job safely and confidently. Safety training starts on day one as part of new employee orientation and continues throughout each employee's career.

## 2. Workforce Safety Projects

In 2018, PG&E deployed several projects designed to improve employee safety. Table 23 summarizes four workforce safety projects. In addition, PG&E continues its phone-free driving policy, which has helped to reduce motor vehicle-related incidents.

**Table 23 – Examples of PG&E's 2018 Workforce Safety Projects**

| Serious Incidents and Fatalities (SIF) | Safety Leadership Development (SLD) | Personal Protective Equipment Matrix/Job Site Safety Analysis Revision | Vehicle Safety Technology – In-Cab Coaching |
|---|---|---|---|
| Program focuses efforts on addressing tasks and incidents that have the potential to cause a Serious Incident or Fatality. Incidents that have potential for serious injury or fatality receive a deeper evaluation and increased management oversight to prevent repeat occurrences.<br><br>[See Section I.3.b. Workforce Safety] | Program designed to improve the enterprise safety performance by improving the leadership experience and awareness of safety behaviors. Taught in six all-day workshops over an 18-month period, this program includes one-on-one coaching by Safety Leadership Coaches and 360-degree feedback surveys.<br><br>At the end of 2017, 86 percent of the 209 leaders, including supervisors and foremen, started and completed the six sessions of training.<br><br>In 2018, the remaining 14 percent of leaders in Gas completed SLD. Additional crew leads were provided a 2-day crew lead course with similar leadership development content. | Collaborative development of a field guide, available for use by all employees, to evaluate the correct Personal Protective Equipment for the task being performed. The project team developed a matrix based on the tasks performed by each department with a goal of reducing injuries due to incorrect Personal Protective Equipment.<br><br>The Job-Site Safety Analysis document was also revised to include Serious Injury or Fatality Checklist. If tasks are conducted that have a potential for a SIF, employees will have additional discussions using the SIF Field Guide to mitigate the additional hazards. | Program focuses on in-cab coaching technology in PG&E vehicles to help us become better drivers. The tool provides real-time, audible feedback to the driver when risky behaviors occur, such as speeding, hard acceleration and hard braking.<br><br>In 2018, over 2,600 vehicles were equipped with an in-cab coaching device.<br>[See Section I.3.b Workforce Safety] |

## 3. WORKFORCE TRAINING

**Figure 54 – A portion of PG&E's Utility Village at the Gas Safety Academy**

In August 2017, PG&E opened a state-of-the-art gas training facility, the PG&E Gas Safety Academy in Winters, California. The facility's master plan was established following industry benchmarking by and input from a cross-section of PG&E's technical workforce.

The facility includes a utility village which provides realistic residential and commercial scenarios for leak survey, leak pinpointing, and emergency response. Other features include an industry-leading M&C flow lab to provide hands-on training for instrumentation and regulation equipment, a construction training area that includes hands-on excavation, shoring, other construction-related activities, and an excavator simulation room.

**Table 24 – PG&E Number of Courses Developed or Enhanced from 2012 through 2018**

| | |
|---|---|
| 2018 | 122 |
| 2017 | 162 |
| 2016 | 214 |
| 2015 | 107 |
| 2014 | 78 |
| 2013 | 88 |
| 2012 | 14 |
| Total | 785 |

In 2018, Gas Operations trained approximately 22,894 student days, including technical, apprentice, and leadership. As of December 31, 2018, PG&E had developed or enhanced 785 courses since 2012 (Table 24).

In 2018, the Gas Safety Academy became certified as a Class A test facility through the Department of Motor Vehicles, so PG&E employees can train and test to obtain their Class A Driver license. In addition, the weld shop at the Gas Safety Academy became an accredited test facility through the American Welding society. PG&E continues to enhance and continuously improve the training, so that all classifications in Gas Operations have initial and refresher training. For example, in 2018, the Locate and Mark Program was revised to include both classroom and structured on-the-job training. The Locate and Mark Program was accredited by the National Utility Locating Contractors Association as an accredited locating and training company. PG&E also converted to a new crane testing and certification process through the National Commission for the Certification of Crane Operators and successfully had 333 employees certified in 2018. In late 2018 and transitioning into 2019, PG&E Academy continues to partner with the Gas Qualifications Department to prioritize and create Operator Qualification refresher training to ensure a skilled, qualified, and competent Gas Operations workforce.

In addition to providing employees training, PG&E Academy partnered with the Gas Public Safety department to develop gas safety training for emergency first responders in the 373 fire departments within PG&E's gas service territory.

The goal of PG&E Academy is to continuously maintain our curriculum to ensure it mirrors current safety practices, procedures, regulatory requirements and new equipment in the field. The recommendations in Table 25 are the output of a partnership between the line of business, SMEs, and PG&E Academy. The importance of the partnership is to ensure that PG&E Academy's projects are aligned to Gas Operations key initiative and high-risk, high consequence tasks utilizing SME expertise to ensure that the training mirrors actual field conditions and scenarios. The purpose of the partnership is that employees are trained to be safe, competent, and compliant to effectively perform the job task or function trained.

**Table 25 – Gas Operation Training Recommendations 2012-2018**

| 2012 Recommendation | Progress as of Dec 31, 2018 |
|---|---|
| Develop programs that support employees throughout their career | • Courses were developed and aligned to business need and results are measurable.<br>• Completed and enhanced apprentice and new employee programs developed to advance employees to journey-level competency.<br>• Increased focus on refresher training to maintain skill and competence of existing workforce. |
| Broaden technology solutions and leverage external curriculum | • Tablets deployed at new Gas Safety Academy.<br>• A Virtual Learning (VL) studio was commissioned and placed in service at the Gas Safety Academy in Winters. Five additional topic areas were taught as VL in 2018 – which reduces non-productive time and travel costs and increases consistency and quality of procedural updates and training. |
| Implement continuous training improvement processes | • The Gas Operations Training Governance Committee has continued to review and approve all redesigned and new curriculum.<br>• Training Effectiveness studies in partnership with Quality Management and Operator Qualifications teams to determine how effective key training programs are and how to improve them.<br>• The Academy partnered with the LOB and the Gas Qualifications department to develop technical training and qualification profiles for Gas Operations employees to ensure consistency amongst job classifications and to provide line of sight into who is trained and qualified to perform the work. |

## 4. Gas Operator Qualifications

PG&E's Gas Qualifications Department maintains and implements qualification programs covering welding, plastic pipe joining, and operator qualifications pursuant to federal and state regulations and industry best-practices.

PG&E requires that all employees, contractors and third-party installers of pipelines be appropriately trained, and possess all requisite qualifications to perform tasks on pipeline facilities. A qualified operator has the expertise to complete work correctly and is part of the team that helps PG&E meet its commitment to public and employee safety.

**Figure 55 – Employees Taking Written Operator Qualification Exam**

Pipeline tasks require specific competencies to be performed safely and reliably. These competencies are

reflected in the "Knowledge, Skills, and Abilities" (KSA) needed for each task; KSAs are determined by a group of SMEs specific to each topic. An individual's KSAs are assessed via a combination of written and performance (practical demonstration) evaluations and candidates must score 100 percent on each component of an exam to be "qualified." Evaluations are primarily geared towards safety and recognizing and addressing Abnormal Operating Conditions (ACC). Qualifications must be renewed every six months, one year or three years depending on the task and applicable regulations.

The CPUC's GO 112-F added new construction activities to the federal definition of covered tasks, effective in 2017. This rule change expanded PG&E's list of tasks for which a qualification is required. The expansion is a significant development in the Operator Qualification Program and involves PG&E employees, contractors, and third-party installers working on PG&E pipeline assets. In 2018, PG&E began administering the new construction qualification exam to comply with the new requirement.

Personnel in training gain hands-on experience working under the direction and observation of a qualified employee. Working under the direction and observation of a qualified person allows a person in training to practice his or her skills in real-world conditions and gives the qualified person the opportunity to advise, to correct, and if required for safety, to take over the performance of the task.

By maintaining a qualified workforce, PG&E is in position to quickly and competently recognize and respond to any AOCs that may pose a threat to the safety of the public, employees or assets.

PG&E's Gas Qualifications Department actively participates in benchmarking and process improvement initiatives with other utilities and other industries across the country to continuously find ways to increase the expertise of the workforce. Currently, PG&E is a voting member on an ASME industry best practice standard, called Pipeline Personnel Qualification,[37] which aims to further improve the regulations covering gas industry qualifications.

## 5. Contractor Safety, Training and Oversight

Contractors are an important aspect of PG&E's technical workforce. Since contractors often work with PG&E's assets and infrastructure that directly impact employee and public safety, the Company holds contractors to the same standard of safety as PG&E employees. The CPUC's Safety Culture OII proceeding (I.15-08-019) included a report that evaluated PG&E's safety practices, including those in Gas Operations. The report recommended that the Gas organization update the contractor safety procedure to clarify responsibilities and reflect current organizations and processes, including guidelines regarding frequency of field observations. As a result, PG&E revised its Contractor Oversight Procedures in 2018.[38] The revised procedures will continue to follow a four-step process (Figure 56) for contractor safety, training and oversight. Other revisions included clarity on the number of observations to be completed for contractors performing high and medium risk work. Process improvements include contractor


**Figure 56 – Four Step Process to Contractor Safety and Oversight**

badging and a corporate contractor safety on-boarding course that all contractors must complete before working for PG&E.

Prior to starting a job, PG&E *pre-qualifies* contractors and subcontractors, and confirms they are qualified to complete the contracted work. PG&E continues to improve its contractor pre-qualification process. PG&E evaluates the contractor's qualifications and performance results, including a host of personnel injury performance metrics. As part of this qualification, contractors on major capital and expense projects such as strength testing, pipe replacement, valve automation, and ILI, are also given in-person and computer-based training on PG&E's quality and safety expectations, and typical hazards associated with the work.

Once construction on a project has started, PG&E carries out a *plan* for contractor performance and clearly communicates contract terms that hold contractors accountable for safety and quality. Job-site observations start during pre-job walk-throughs to evaluate site specific hazards prior to starting work.

PG&E then schedules regular meetings with contractors to *oversee* their work and confirm expectations are met. In addition to regular oversight, PG&E inspects contractor work and a Quality Assurance (QA) team randomly checks project completion from beginning to end. On a quarterly basis, PG&E's leadership and contractor leadership meet to understand opportunities to improve the overall Contractor Safety and Oversight Program.

After the job is complete, PG&E *evaluates* the contractor's performance using a scorecard that includes metrics on safety performance and contractual obligations. Contractors also have the opportunity to provide feedback to PG&E through a similar scorecard.

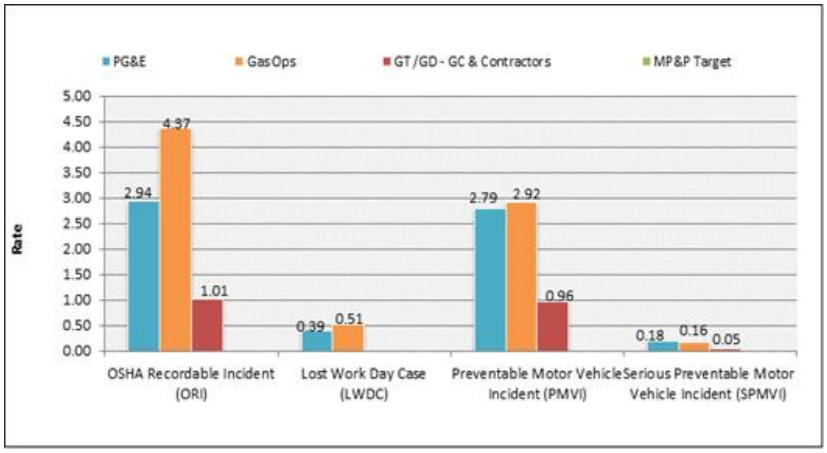


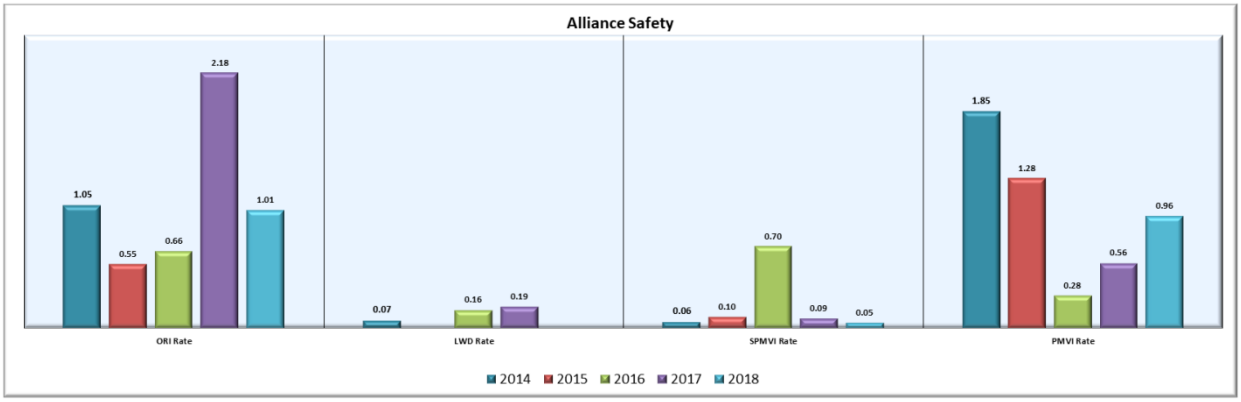

**Figure 57 – 2018 Safety Performance**

Contractor performance is tracked throughout the year and compared to Company performance. Figure 57 provides 2018 metrics on injuries and motor vehicle incidents. In 2018, PG&E Construction

Crews and Contractors (see the red bar in Figure 57) outperformed in all performance metrics when compared to Gas Operations and PG&E as a whole, and worked over 3 million hours performing higher risk work.

Year-over-year reductions in all four categories show the shift in safety behaviors and culture for Alliance Contractors. As depicted in Figure 58, the data demonstrates that between 2014 and 2018, OSHA recordables (ORI) were consistent with the exception of 2017. Lost Work Days (LWD) have remained relatively flat. SPMVIs have remained relatively flat with the exception of 2016. The PMVI Rates have fluctuated over the years; however, increased focused on tight manueavering vehicle movements and backing will be the focus for 2019 as they were the highest trends for us over the last five years.

**Figure 58 – Strategic Partner Safety Year Over Year Performance**




**PG&E believes that employees who are engaged at work and who feel recognized are far more likely to work safer, be more productive, make better decisions and produce higher quality work.**

As PG&E strives to improve project safety, quality and productivity, the Company takes every opportunity to catch people doing things right and recognize them for their specific efforts, innovations, contributions, hard work, safe work practices, good decisions, great planning, timely completion or any other specific accomplishment--no matter how small. In 2018, there was an up-tick to over 850 quality "Good Catches" turned in to PG&E's safety and construction management function. This is a 6 percent increase compared to 2017. Everybody that turned in a "Good Catch" was recognized and the "Good Catches" were shared on a weekly call with all PG&E construction and contractor leadership. Contractors continue to speak up to raise awareness and share best practices.

## 6. Partnership With Labor Unions

Union-represented employees make up almost 69 percent of PG&E's Gas workforce, and are integral to the Company providing safe and reliable gas service. PG&E frequently works with its union partners to identify opportunities for training, process improvement, and other investments in the safety of its union-represented employees and the public. In 2018, PG&E continued to collaborate with union leadership on projects such as improving emergency response and "make safe" times for blowing gas situations, enhanced lines of progression, the affordability initiatives, Estimating in Training Program, Grassroots Safety Committee Partnership, and PG&E's Leak Survey Optimization Program.


**Figure 59 – 69 Percent of Gas Operations' Workforce Is Represented by the IBEW and the ESC**

The line of progression effort has updated job duties, training and certification for almost every represented field-based position. These changes have driven improved training and certifications for the Company's workforce (NACE certification[39] for corrosion mechanics, as one example), improving the safe and compliant delivery of service.

# VI. Compliance Framework

PG&E transports and stores natural gas under the requirements of state and federal safety regulations. In 2016, PG&E adopted the Compliance Maturity Model to standardize and assess its regulatory compliance processes against industry best practices. The Model is composed of eight elements: risk assessment, program governance, guidance documents, compliance controls, communications and training, monitoring and auditing, investigation and response, and enforcement and incentives. Each element in turn has five performance thresholds. This framework provides Gas Operations a uniform outline from which to assess the performance of PG&E's compliance processes against their regulatory requirements. In 2016, a baseline performance assessment was conducted, and in 2017 the business began the work of aligning federal and state regulatory requirements to our processes and conducted periodic re-assessments against the framework's tiered performance thresholds. In 2018, Gas Operations achieved level three compliance maturity for five of the eight program elements; the remaining three elements will be reviewed in 2019. Programmatic and process controls are undergoing a strengthening to ensure that the business is both compliant with

current regulations, as well as prepared to successfully implement new and changing regulations effectively.

The Compliance Maturity Model aims to bring visibility to PG&E's regulatory requirements, validate that controls are in place to meet those requirements, and structure the monitoring and testing of those controls for effectiveness while maintaining adequate programmatic oversight to keep compliance at the core of the work that we do. This approach aligns with the "Plan, Do, Check, Act" management method that PG&E employs throughout its operations as part of Gas Safety Excellence.

While the Compliance Maturity Model structures PG&E's strategic approach to compliance, day-to-day compliance performance continues to be built upon four key enablers:

- Employee expertise
- Providing employees the right information at the right time
- Making available the right resources at the right time
- Implementing supportive controls

## 1. Building Expertise

PG&E employees require specialized skills to be able to perform their jobs constructing, operating and maintaining the natural gas systems. As detailed in *Workforce Training (Section V.3.)* and *Gas Operator Qualifications (Section V.4)*, the Company recognizes that its employees are a critical element in the compliant operation of the pipeline system every day; competent and capable employees perform work safely, effectively, and efficiently while using their knowledge and experience to identify and raise opportunities for continuous improvement.

## 2. The Right Information to Do the Work

A highly-skilled workforce is most effective when enabled with timely, accurate information from which to work. Gas pipeline work is highly technical, and if not performed correctly, could result in serious safety concerns. To enable the consistent performance of work across our service territory, written guidance documents, such as procedures and job aids, are utilized. These documents are stored electronically in the Technical Information Library and are reviewed on a routine basis so that that they reflect both regulatory requirements and best practices, as well as any lessons learned from Company or industry experiences. While this review and revision practice keeps the Company's processes at a state-of-the-industry level, it also requires significant efforts to keep all personnel performing work in accordance with these documents, are made aware of any changes and are provided with the requisite training and provided access to subject matter experts to maintain compliance.

In 2018, PG&E continued the monthly publication schedule to pace the changes experienced by people performing the work, allowing for more time to receive and digest each change to their work

between the publication date and the effective date of any given change. This shift was accompanied by a new format for email communications that separated changes based on several categories, allowing employees to more efficiently determine relevant changes.

In addition to technical guidance, employees need accurate and timely information about PG&E's pipeline assets. PG&E has two pipeline GIS mapping systems—one for transmission assets, and another for distribution assets. These systems contain geospatial information about the pipeline system including, in majority of the cases, detailed information about asset history, materials, manufacturer, and location. These systems help PG&E to effectively conduct integrity management program work, locate mains and services, and plan for construction. PG&E works continuously to improve the quality of the information in both mapping systems. Given the volume of work performed on the pipeline systems every day, it is critical to have processes that update these mapping systems accurately, and in a timely manner. As prescribed in the Compliance Maturity Model, compliance goals need to be accompanied by effective controls and performance monitoring.

## 3. The Right Resources to Do the Job

Once the correct work has been identified, PG&E determines the number of employees, contractors, and tools needed to complete that work. For example, in 2018, for Locate and Mark, PG&E added 13 employees, approximately a 7 percent increase from 2017. In 2018, PG&E added four new contractor companies to assist with Maintenance and Construction activities. In addition, PG&E continues to invest in tools to expand our capabilities; for example, state-of-the-art patrol aircraft, mobile devices, and camera technology.

## 4. Supportive Controls

A compliant company utilizes numerous processes and programs to perform at a high level; some are aimed at monitoring or improving internal processes with corresponding compliance requirements and other are aimed externally, to help PG&E identify opportunities for continuous improvement or pending regulatory changes. Table 26 below details some of these processes and programs.

**Table 26 – Compliance Processes and Programs**

**Quality Management (QM)** –The QM group assesses and provides direct feedback on the work quality for PG&E's important safety programs, including locate and mark, regulator station maintenance, and as-built record development. [See Section VII.4 *Quality Management*].

**Internal Audit (IA)** – PG&E's IA team performs arm's length reviews for all the Company's lines of business, including Gas Operations, and is responsible for assessing control adequacy.

**Non-compliance Self-Reporting** – PG&E is committed to self-reporting compliance issues and taking prompt mitigative and corrective action to prevent recurrence. PG&E filed 3 Self-Reports in 2018 in accordance with the Safety Citation Decision.

**Participation in Safety and Enforcement Division (SED) Inspections** – In advance of CPUC Safety and Enforcement Division (SED) inspections, PG&E self-evaluates gas divisions, districts and programs, such as Operator Qualification, Emergency Management and Integrity Management, and shares findings with the SED. PG&E's assessors spent approximately 12,000 hours in 2018 identifying issues and supporting resolution. PG&E strives to resolve identified issues within the same inspection cycle and respond to any data requests within the duration of the inspection.

**Cause Evaluation** – Similar to the continuous improvement mechanism in PG&E's Process Safety management framework, cause evaluations are post-incident investigations that include an incident analysis and recommendations to prevent or mitigate future reoccurrence. Cause evaluations are conducted based on business determination of identified issues. The Gas CAP team completed over 150 cause evaluations in 2018.

**Evaluation of National Transportation Safety Board (NTSB) Reports** – The NTSB investigates all serious pipeline incidents. PG&E SMEs routinely review NTSB reports to learn from pipeline incidents. As a result, PG&E may adopt new approaches to addressing threats, change work procedures or develop new training.

**Evaluation of Pipeline and Hazardous Materials Safety Administration (PHMSA) Bulletins** – PHMSA regularly issues safety advisories for pipeline operators. As new safety information comes to light at other gas companies in the US, PHMSA issues bulletins to help operators take preventative action.

# VII. CONTINUOUS IMPROVEMENT

Continuous Improvement is the mechanism through which PG&E continues to evolve from being reactive to proactive in the journey to Gas Safety Excellence. By continuously taking a critical eye to existing practices, and identifying the cause of challenges that arise, PG&E can move to correct problems before they result in compliance violations or in harm to PG&E employees or the public. While continuous improvement is embedded in PG&E programs, a few programs are highlighted below.

## 1. GAS STEWARDSHIP


The Gas Stewardship Office, established in 2017, leads Gas Operations' efforts to drive process performance management conversations and continuous improvement activities into our safety and reliability work, and to create a more affordable, compliant gas system without compromising safety or quality.

Gas Operations has embraced the notion that safety and affordability are not a trade off, but instead can be accomplished at the same time. The Stewardship Office works with key stakeholders within Gas Operations to continually identify process performance improvement opportunities and develop initiatives to implement those improvement plans.

Initiatives are generated from two main sources. First, process teams host ideation sessions to identify opportunities within its process to yield improvements. Second, any employee or contractor can submit ideas through CAP and items are flagged as affordability ideas which are then forwarded to process teams for consideration. Over 400 initiatives impacting distribution and transmission operations are currently being pursued within Gas Stewardship.

In 2017, Gas Operations implemented a tool to track and manage all Gas Stewardship initiatives from inception to completion, and uses the tool to manage progress on continuous improvement initiatives daily.

Of the current initiatives being managed within Gas Stewardship, all of them intend to either improve the safety, affordability, quality, compliance, and/or reliability of the gas transmission and distribution system. The Gas Operations Senior Leadership team performs a three-element review process on all new initiatives, reviewing each initiative to ensure it would not negatively impact safety, compliance or regulatory obligations. In addition, the Stewardship Office along with initiative owners and subject matter experts review initiatives with a 10-point filter to account for safety, compliance, regulatory and rate case implications. Initiatives with any potential implications are flagged for further review.

## 2. Lean Capability Center

Gas Operations first efforts to implement a Lean Management System in a few targeted areas was done through its Super Gas Operations (SGO) Department, from 2014 through 2017. SGO worked with the Gas Operations organization to document their processes, roles and responsibilities, and key tasks associated to helping the work performance of the process. SGO also implemented process huddles to have the appropriate discussions with cross-functional teams to understand process issues and address the challenges with the appropriate stakeholders. Key operational and process metrics were included in the huddle to provide visibility regarding the execution of the work plan, confirming that work is prioritized based on compliance and/or customer commitments, and that the job is properly closed in the system and related job documentation. By performing the above items, SGO helped gas teams better plan the work, improve the flow of work, and increase visibility into a rolling 90-day plan of "ready" work.

In 2017, building upon the successes of SGO and Gas Stewardship, Gas Operations began deploying a Lean Management System across the entire LOB. As such, SGO evolved into the Lean Capability Center (LCC)[40] which was created as the centralized hub to support each of the functions within Gas Operations in their deployment of Lean tools and practices. Lean Management (Lean) is PG&E's approach to running

Gas Operations now and into the future. It is an integrated system of principles, practices, and techniques for operational excellence based on empowering the front-line, identifying waste in our processes, and finding opportunities to continuously improve, all supporting the relentless pursuit of serving customers better. Lean improves safety, quality, and affordability while enabling meaningful performance conversations up and down the organization.

Lean is a system of complementary tools that are incorporated into the four pillars of our Lean Management system, which are referred to as "loops" because they must happen in continual cycles. These tools are critical to the success of the system.


Figure 60 – Lean Management System in Gas Operations

Examples of Lean tools and practices include: huddles and visual performance management, standard work, waste identification, problem solving, and leader standard work. The LCC is primarily responsible for establishing a consistent Lean deployment strategy for all of Gas Operations, developing Lean curriculum, facilitating training, sharing best practices, building tools to ensure the sustainability of Lean, and supporting the functional teams in their deployment.

Huddles are quick, structured conversations among team members that occur daily or several days a week. Huddles allow the right people discussing the right topics, establish appropriate metrics and targets at each level, and allows leaders to acknowledge great work by teams and/or individuals. Huddles cascade throughout the organization and follow the same general agenda to ensure consistency.

In 2018, over 600 huddles were established across Gas Operations, including huddles at the Senior Vice President level. Information is moving more freely than before from front line supervisors to the Executive level, and vice versa. For example, in 2018, the Corrosion Department used Lean huddles to identify and escalate problems with Indirect Inspection Testing (IIT) field testing reports. Next, they facilitated problem solving and coordinated with key stakeholders to develop a standard work checklist for vendors to ensure inclusion of necessary reporting items. This checklist reduced re-work and hand-offs, both of which are significant sources of waste. Their Lean efforts drastically reduced cycle time, with average report completion reduced from 81 days to 16. Simultaneously, they reduced the IIT report quality finding rate from approximately 24 percent to approximately 12 percent, and alleviated instances of non-compliance with the procedure.

Each function within Gas Operations (e.g., T&D Construction, T&D Operations, etc.) has their own Lean team led by a Functional Lean Leader with a team of Lean Coaches. Their role is to install the Lean tools and behaviors in accordance with deployment plans.

## 3. Process Management

Process Management involves planning, monitoring, and controlling the performance of a business process with the goal of meeting customer and business requirements. Process Management enables individual functions to understand and work towards common process goals. As such, Process Management promotes safety, reduces costs, increases quality and efficiency, and ensures process controls are in place.

The Process Management Playbook uses a 25-step approach to establish process management, which incorporates Lean principles and includes developing metrics, confirming the right controls are in place, and ongoing monitoring of performance. In 2018, Process Management efforts focused on processes with a significant impact (those with a high safety and/or quality risk, high number of compliance findings, etc.). Process Management teams include Process Owners, Process Managers, Process Analysts, and other key stakeholders.

For example, the Distribution Maintenance process management team within T&D Operations developed Close-Out Documentation metrics. In mid-2016, the team began capturing a metric that measures the number of days to prepare the documentation after construction completion to Compliance Desk (CD) for quality control review.

When finalizing construction work, it is important for employees to complete the required job package as part of the close out documentation. It captures the work performed on the asset and helps properly record the units in our system of record. Documentation timeliness increases asset record accuracy, which in turn increases safety for employees, customers, and system operations.

For documentation preparation (from construction completion to CD), performance improved by almost 50 percent, showing an average of 5.0 days by end of 2016, an average of 4.5 days in 2017 and an average of 3 days in 2018. See Figure 61.

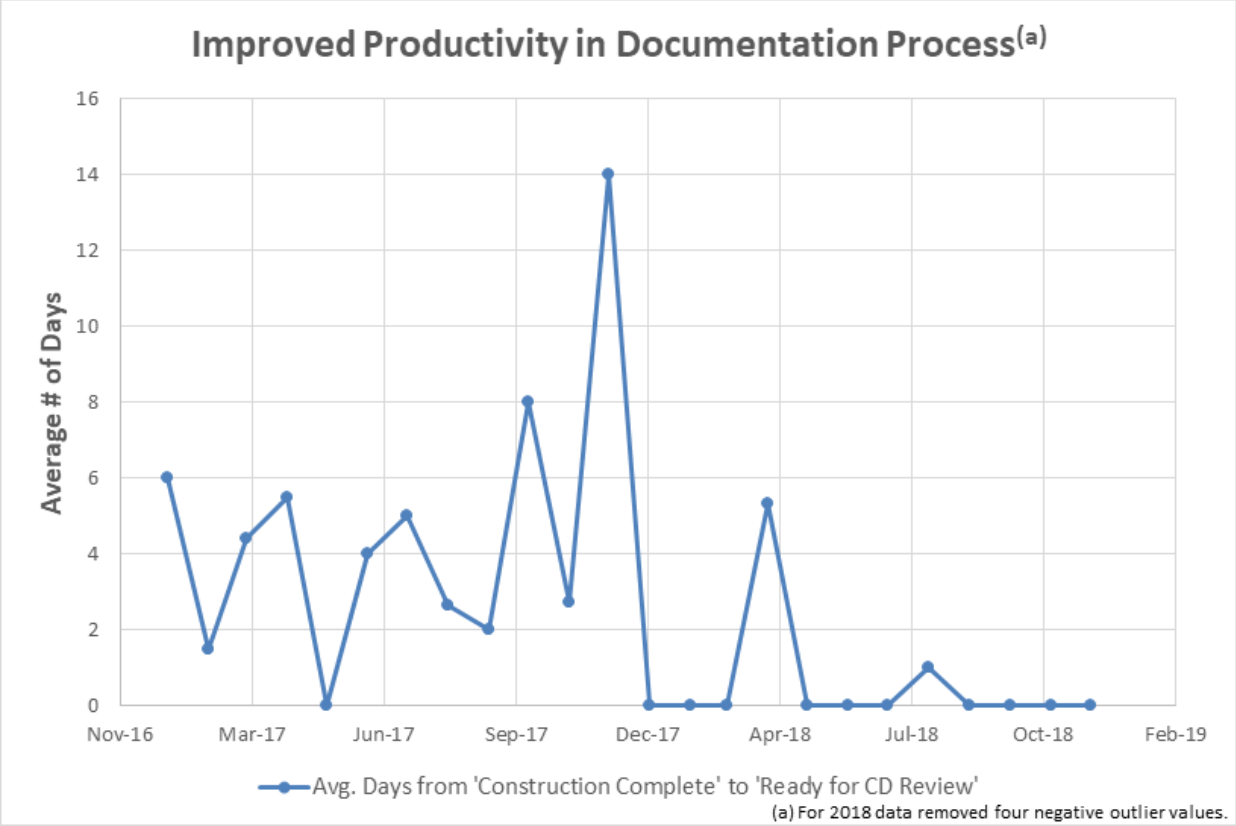



**Figure 61 – Improved Productivity in Documentation Process**

In addition to Close Out metrics, T&D Operations' CD team measured Documentation Quality. CD uses two methods to measure and develop these metrics.

- Method 1 calculates the total number of major errors found in all records in one period vs. total number of potential errors in these records (multiply by 100).
- Method 2 calculates the ratio of the number of records with at least one major error vs. the number of total records reviewed.

Since the SGO Program began in 2014 and evolved into Lean, errors in as-built documentation for the Distribution Maintenance process decreased by 90 percent by end of 2016, then continued to slowly drop. Distribution Maintenance realized many benefits, such as improved documentation productivity and documentation quality, which increased visibility to the work plan and strengthened the safety on actual construction activities. In 2018, the focus was sustaining this improvement on both the documentation productivity and quality. While there was a slight increase in 2018, the errors in as-built

documentation were significantly less than when we began this process. We remain focused on maintaining and improving performance.

As we continue to deploy the Lean Management System, Process Owners with support from the LCC will continue applying the Process Management Framework to improve the maturity of PG&E's processes.

## 4. Quality Management

The Gas Quality Management (QM) organization is responsible for centralized QA activities and helps others integrate QC points into processes within Gas Operations. QA activities include conducting quality assessments in the field and reviewing documentation and records, either as work is being performed or after-the-fact. Both approaches allow for mentoring and coaching opportunities for the people doing the work and to make corrections, when needed. In 2018, QM expanded its corrosion control program and added field assessments of exposed pipe. 2018 was a development and pilot year for this expanded program, which will be fully implemented in 2019. There are currently 16 active QM programs as of December 2018 and are shown in Table 27 below.

| Table 27 – List of Quality Management Programs as of 2018 | |
|---|---|
| Leak Survey | Post-Repair Leak Survey |
| Locate and Mark | Distribution Construction |
| Field Service | Transmission Construction |
| Valve Maintenance | Regulator Station Maintenance |
| Corrosion Control | Rotary Meter Installation and Maintenance |
| Internal Records Review | Gas Transmission and Distribution As-Builts |
| Chain of Custody | Atmospheric Corrosion Meter Inspections |
| QA Pipeline Features List (PFL) | Post Construction Asset Validation |

Continuing the journey to mature the Gas Operations QMS and build on continuous quality improvement, field quality control programs were further developed in 2017 within the T&D Construction and T&D Operations organizations. The T&D Construction organization was able to start implementing its field QC program in 2017, and T&D Operations is continuing to roll out its field QC Program into 2019. The Gas Operations organization continues to increase focus on quality control in order to identify defects early, ensure quality is controlled, and that work performance and documentation is of high quality to meet our safety, compliance, and customer expectations.

The fundamental principles in the QMS leverage the "Plan, Do, Check, Act" (PDCA) framework (refer to Figure 62) that is instrumental to PG&E's implementation of Gas Safety Excellence. PDCA is an iterative four-step management method used in business for the control and continuous improvement of

processes and products. Just as a circle has no end, the PDCA cycle should be repeated for continuous improvement.


**Figure 62 – The Quality Management System**

Accomplishments in 2018 include:

- Performed 6,350 quality assessments in the field and 25,504 in the office;
- Removed “critical” as a category of finding from the QM Field program to align with industry practice;
- Developed and piloted field assessments of exposed pipe, as part of the corrosion control program;
- Conducted additional QA assessments to support the leak re-check initiative;
- Redefined the definitions for High/Medium/Low findings to align with the Gas CAP risk ranking process, while maintaining focus on compliance and safety;
- Aligned the QA Data attribute checklists with the QC organizations;
- Instituted lean capabilities for QA Data by establishing “one source of truth” for assessment and high finding information; and

- Provided support to the Camp Fire response/recovery efforts in performing safety observations of work being performed.

Because of these accomplishments, the QA Field Quality Index metric that provides insights on quality for the key processes in Gas Operations improved from 2017-2018, with an approximate 19 percent reduction in the number of high findings.[41] Refer to Figure 63 for 2018 performance, which shows the total cumulative number of 259 high findings for QA Field.

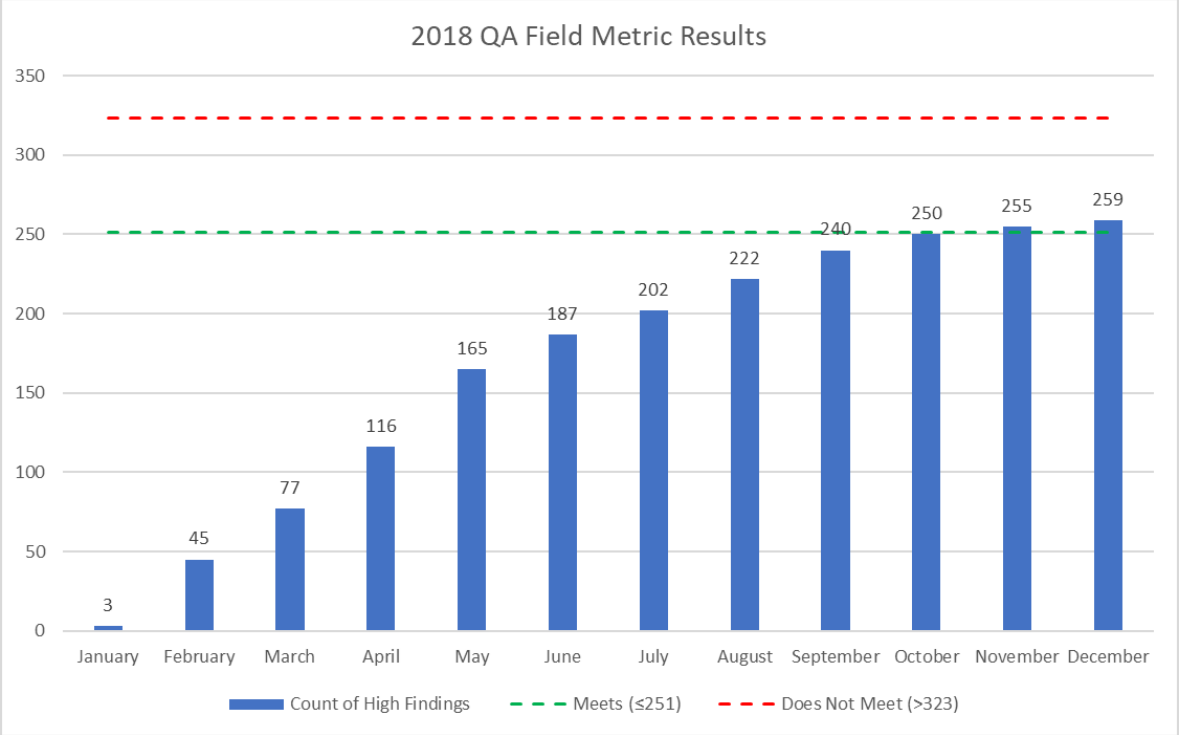



**Figure 63 – 2018 QA Field Metric Performance**

## 5. Research and Development

The Research and Development and Innovation (R&D and Innovation) Group brings innovative technologies and solutions from industry, government, and academia to the Gas Operations. PG&E continues to use the Center for Gas Safety and Innovation in Dublin, California which opened in 2017. This facility consists of work and lab space that houses groups within Gas Operations and provides them with advanced tools, testing capabilities and lab resources, with the goal of continuing to lead in the development

**Figure 64 – Field Test of The Plastic Insert Detection Tool**

of new methods and technologies to enhance gas safety. The work performed at this facility includes, among other things, working with other industry participants to find and test new products and processes, testing and evaluating Measurement and Control devices that contribute to the safety of PG&E's gas system, and conducting Non-Destructive Examination on PG&E's pipelines to ensure asset integrity.

In 2018, the R&D team partnered with leading U.S. utilities and R&D organizations to manage and implement a broad portfolio of more than 200 projects. In recognition of PG&E's innovation efforts and leadership, PG&E's R&D Manager François Rongere received the John B. McGowan Senior Research Award from the American Gas Association.

R&D is embedded in Gas Operations through Gas Safety Excellence and the continuous improvement process. R&D's work is prioritized based on the results of the Risk Management Process, so projects and innovations align with the most critical needs of the business [see Section IV.3. *Risk Management Process*].

PG&E participates in collaborative efforts with national and international R&D organizations such as PRCI, NYSEARCH, and Operations Technology Development (OTD)/Gas Technology Institute. PG&E also works closely with R&D programs at the California Energy Commission, PHMSA, the CARB and the Department of Energy.

Examples of 2018 collaborations include:

- Building upon promising results obtained in 2017 on Large Standoff Magnetometry, which is used to detect stress and defects on buried steel pipelines from above ground, other gas operators joined to co-fund a collaborative project with PRCI to investigate and model the fundamental phenomena that support the technology and to build, with suppliers, solid practices providing reliable diagnostics.
- Forming a large consortium in 2018 to industrialize a product able to detect obstacles in front of the rod of a horizontal drilling machine based on the technology ORFEUS developed in Europe and demonstrated at PG&E by OTD in 2017. The consortium also secured $1 million of funding by PHMSA.
- Continuing progress on the robotic platform developed through NYSEARCH to inspect complex pipelines inaccessible to traditional ILI tools. In 2018, the consortium made progress in extending the range of the robot using embedded energy harvesting.

R&D and Innovation was asked a few years ago to develop a new method to easily detect the presence of plastic pipe inserted into steel pipelines. A breakthrough was reached in 2018 when it was demonstrated that an ultrasonic device specially designed for this purpose can provide simple and reliable detection. This tool will allow construction crews to determine if the presence of a plastic insert

in a steel pipeline may create a risk to welding operations. A simple YES/NO interface provides the answer after a few seconds. It does not require any signal processing expertise. The tool has been tested in the laboratory and progressively improved to the point that it could be demonstrated in the field on live pipelines. The industrialization of the product is on its way now for completion in 2019.

## 6. Benchmarking and Best Practices

Benchmarking is an important step in PG&E's overall continuous improvement effort and is used to identify industry best practices. Best practices include, but are not limited to, widely-recognized natural gas practices that directly enhance public and personnel safety over time. Benchmarking is one component of understanding what may constitute an industry best practice and is accomplished by both formal and informal means. There may also be more than one single industry "best practice" in any given program area. Therefore, PG&E's best practice identification often begins with identifying a published industry standard that provides guidance and sets overall direction for a program or technical discipline and discussing with other utilities. When standards are not readily identifiable, PG&E may employ various methods, such as reaching out to industry associations, experts, and other utilities, to discuss best program approaches, and then develop detailed procedure manuals to document the practices. PG&E relies on various outlets for benchmarking best practices such as reviewing standards written by SMEs and public agency publications, and participating in industry associations. How PG&E utilizes each of these outlets is described in the next sections.

**BEST PRACTICES**

- Program Coordinator
- Steering Committee Member

**DISCUSSION GROUPS**

- Compression Operations
- Damage Prevention
- GPS/GIS and Work Management Systems
- Management of Company Standards
- Pipeline Expansion
- Pipeline Safety Management System Management
- Pipeline Safety, Compliance, Oversight
- Quality Management Task Group
- TIMP Risk Models

**OPERATIONS COMMITTEES**

- Building Energy Codes and Standards Committee
- Corrosion Control Committee
- Distribution and Transmission Engineering
- Distribution Construction and Maintenance
- Distribution Measurement Committee
- Gas Control Committee
- Operating Section Managing Committee
- Operations Safety Regulatory Action Committee
- Plastic Materials Committee
- Process Safety Committee
- Safety and Occupational Health Committee
- Supplemental Gas Committee
- Transmission Measurement Committee
- Transmission Pipeline Operations Committee
- Underground Storage Committee
- Utility and Customer Field Services Committee

### a) Industry Standards Written by Subject Matter Experts

One informal benchmarking practice that PG&E pursues is identification and use of standards written and reviewed by SMEs. Sometimes these standards are referred to as "consensus" standards, meaning that the publisher believes that they represent proven practices in that particular field. In addition to seeking best practice standards that originate in the U.S., PG&E identifies international standards for best practices, including European and ISO. PG&E has adopted for use several European

standards. In another example, PG&E pursued the certification of ISO 55001, the recently available international asset management standard, and has both achieved and sustained certification.

PG&E relies on associations such as the ASME and the API, to facilitate the development of best practices, prescribe codes and standards for the natural gas industry, to provide forums such as conferences and meetings for like members to learn about relevant best practices, publish best practice literature, industry reports, and relevant industry statistics, and to provide technical continuing education. Some of PG&E's foundational risk management and gas program activities follow ASME standards and API consensus standards that are referenced in code, such as B31.8S, Managing System Integrity of Pipeline Systems and RP 1162, Public Awareness programs.

## b) Agency Publications

PG&E reviews relevant agency documents to gain insight into what regulatory and investigation agencies view as best practices. PG&E incorporates input from previous proceedings and reviews, including the CPUC, the NTSB, PHMSA, and reviewers contracted by these entities.

As an example, PG&E has a procedure to ensure appropriate responses to PHMSA advisories and any proposed or final rulemaking notices from other regulatory agencies. The procedure expedites reviewing, assigning, and tracking of all Gas T&D related advisory bulletins and proposed or final rulemaking notices from any regulatory agency in a timely manner.

## c) Peer Associations

Benchmarking is performed with a variety of utility and non-utility entities to improve PG&E's understanding of how other companies manage various operational programs, including best practices related to safety. For instance, PG&E personnel learn about best practices from interacting with peers and industry experts in organizations such as the INGAA, AGA, NACE International (formerly known as the National Association of Corrosion Engineers), API, ASME, Southern Gas Association, Public Service Enterprise Group (PSEG), the Common Ground Alliance and other organizations.

PG&E employees participate in and present at a variety of industry conferences. These conferences are gatherings of industry representatives with similar backgrounds to discuss best practices, review emerging practices, share operating information, and build networks for future best practice sharing. Some of the peer-to-peer associations PG&E participates in are described below in more detail.

## d) American Gas Association

As part of PG&E's continuous improvement commitment to safety in Gas Operations, the Company is an active member of the AGA. The AGA helps PG&E share, validate and learn about gas safety best practices through targeted Operating Committees and Discussion groups with peer organizations. For

example, PG&E participates in the AGA SOS Survey Program by both distributing and responding to surveys with topic-specific information requests throughout the year and utilizes the data provided by other U.S. utility gas companies. In 2018, as part of the AGA effort to publish a whitepaper of best practices relating to OP events, NISOURCE consulted PG&E on our experience and practices regarding utilization pressure systems, also known as low pressure systems.

### e) Interstate Natural Gas Association of America

The INGAA and the INGAA Foundation develop consensus guidelines and position papers based on the input of its members. PG&E considers these materials to constitute evidence of natural gas transmission pipeline companies "best practices" and are widely recognized in the industry as such. INGAA has a membership base that owns approximately 200,000 miles of natural gas pipeline in the U.S. PG&E relies on INGAA to facilitate the identification, development and sharing of best practice materials.

### f) National Association of Corrosion Engineers International

PG&E also relies on NACE International to identify and develop standards, test methods and material recommendations that are widely regarded as best in the field of corrosion and specifically for Cathodic Protection and coatings. NACE International creates these materials through the subject matter expertise of its members. NACE International has over 28,000 members in over 100 countries.

### g) Western Energy Institute

The Western Energy Institute (WEI) is the premier Western association of energy companies that implements strategic, member-driven forums, identifies critical industry issues and facilitates dynamic and timely employee development opportunities. WEI provides forums for exchanging timely information on critical industry issues, information about industry best practices and skills training. PG&E also participates on several committees.

### h) Public Service Enterprise Group

The PSEG is a publicly traded diversified energy company headquartered in Newark, New Jersey and was established in 1985. The company's largest subsidiary is Public Service Electric and Gas Company (PSE&G).

The Gas and Electric Utility Peer Panel was established in 1993 and is a collaborative effort between member utility companies that focus on sharing benchmark data on an annual basis.

PSE&G developed the panel of companies for exchanging accurate and meaningful data on key performance metrics.

### i) Additional Benchmarking Efforts

In addition to the numerous associations, PG&E also uses informal means of benchmarking including using the expertise brought to the Company by new-hires and contractors with industry experience, by attending trade conferences, and by information sharing with other utilities.

PG&E also uses benchmarking to facilitate continuous improvement. When possible, PG&E benchmarks metrics to understand performance against peers.

Industry performance also informs target-setting. The following chart lists a few key safety metrics that PG&E benchmarks against other utilities:

**Table 28 – Key Benchmarking Metrics**

| PG&E's Commitment to Safety | Measurement |
|---|---|
| Emergency Odor Response | Average response time |
| Year-End Grade 2 Leak Backlog | Per 1,000 miles of mains and services |
| Year-End Grade 3 Leak Backlog | Per 1,000 miles of mains and services |
| Lost Work Day Case Rate [(a)] | Lost work days per 200,00 hours worked |
| Third Party Dig-In Reduction | Number of dig-in incidents per 1,000 tickets |

_____

(a) This measure is benchmarked at the Company level.
Comparative data associated with these benchmarks may be protected by confidentiality or non-disclosure agreements.

## VIII. Conclusion

The 2019 Gas Safety Plan update demonstrates PG&E's commitment and progress in implementing processes, programs, and procedures to achieve its vision to becoming the safest and most reliable natural gas utility in the nation even in the midst of current challenges. The Gas Safety Excellence Management System guides how PG&E operates, conducts, and manages all parts of its business by putting the safety of the public, PG&E's customers, and PG&E's employees and contractors at the center of its work; investing in the reliability and integrity of its gas system; and, by continuously improving the effectiveness and affordability of its processes. PG&E has made continued progress, but recognizes that there is more to be done in its journey to achieve Gas Safety Excellence.

# IX. ENDNOTES

1 In October 2011, the California legislature signed into law Senate Bill (SB) 705, which declared "[i]t is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority." SB 705 was codified as Public Utilities Code §§ 961 and 963(b)(3).

2 PG&E's Integrated Planning Process begins with Executive Guidance that provides the North Star for the Company and establishes PG&E's goals over the next five years. Session D identifies key risks and compliance issues for the Company and for each LOB. Session 1 outlines each LOB's goals over a 3-5 year timeline and strategies for achieving them. Session 2 translates Session 1 goals and action items from Session D into a work plan, resource plan and budget.

3 American Petroleum Institute's Recommended Practice Pipeline Safety Management System Requirements (RP 1173) outline specific best practices for safe and effective pipeline operations underpinned by a healthy safety culture.

4 3rd quartile as compared to other companies who participate in the same OHI survey administered by PG&E's third-party consultant.

5 This figure shows CAP Throughput, which is being measured in 2019, but was not tracked in 2018.

6 This figure excludes routine mapping corrections.

7 In 2017, a Federal Court-Appointed Monitor was assigned to PG&E to oversee PG&E's safety performance for the period of PG&E's court-ordered probation stemming from its conviction in connection with the San Bruno incident and resulting NTSB investigation.

8 Consistent with CPUC Safety Enforcement Division guidance, see Attachments 4 and 7 for PG&E's 2019 Gas Safety Plan change logs.

9 This system was designed based on the elements of Process Safety developed by the Center for Chemical Process Safety, a branch of the American Institute of Chemical Engineers.

10 API RP 754 identifies leading and lagging indicators for nationwide public reporting, as well as indicators for use at individual facilities including methods for the development and use of performance indicators. This comprehensive leading and lagging indicators program provides useful information for driving improvement and when acted upon contributes to reducing risks of major hazards (e.g., by identifying the underlying causes and taking action to prevent recurrence). The indicators are divided into four tiers that represent a leading and lagging continuum. Tier A is the most lagging and Tier D is the most leading.

11 See ATTACHMENT 3.

12 See PG&E's 2018-02 Gas Transmission & Storage Safety Report and PG&E's 2017-01 Gas Safety Report.

13 American Petroleum Institute (API) Recommended Practices (RP) 1170, Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage. API RP 1170 provides functional recommendations and covers facility geomechanical assessments, cavern well design and drilling, solution mining techniques & operations, including monitoring, and maintenance practices.

14 American Petroleum Institute (API) Recommended Practices (RP) 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs. API RP 1171 recommends that operators manage integrity through monitoring, maintenance and remediation practices and applies specific integrity assessments on a case-by-case basis.

**15** The Transmission Pipe asset family includes valves outside of station boundaries and not otherwise included in the Measurement and Control asset family, which are those valves defined in TD-4551S – Station Critical Documentation. An example of valves included in the Transmission Pipe asset family includes manually operated mainline valves.

**16** As set forth in 49 Code of Federal Regulations (CFR) Part 192, Subpart O.

**17** As evaluated in the Risk Assessment Mitigation Phase (RAMP) model.

**18** As evaluated in the Risk Evaluation Tool for the Risk Register, if not included in the RAMP model.

**19** Gas Operations did not perform a Risk Refresh in 2018. The 2018 Risk Refresh file was updated in the fourth quarter of 2017.

**20** A non-gas customer receives gas from other means, such as propane or other third-parties. Unlike gas customers who receive gas safety information via bill insert or electronic billing statements, a non-gas customer receives a separate direct mailing.

**21** 49 CFR §192.614.

**22** California Government Code §4216.

**23** Investigation (I).18-12-007 Order Instituting Investigation and Order to Show Cause on the Commission's Own Motion into the Operations and Practices of Pacific Gas and Electric Company with Respect to Locate and Mark Practices and Related Matters.

**24** See PG&E's 90-Day Report and Response to Locate and Mark OII Directives 1-5 Submitted March 14, 2019 in (I).18-12-007.

**25** The term cross-bore is broadly defined as an intersection of an existing underground utility or underground structure by a second utility resulting in direct contact between the transactions of the utilities. The cross bore can compromise the integrity of either utility or underground structure. Examples include gas, telecom, water, storm, and sewer among others.

**26** Identified mileage does not include girth welds or branch connections. Additionally, it does not include the miles of pipe that would be necessary when pipe replacements are rolled into engineered projects.

**27** This program does not address the threats posed when natural gas pipelines that cross active earthquake faults. Please refer to PG&E's Earthquake Fault Crossing Program in Section IV.5.i.

**28** Traditional In-Line Inspection is a term used to refer to in-line inspection tools that run via propulsion by the pressure and flows of the gas stream. Non-traditional in-line inspection methods are also being employed by PG&E under some circumstances where pressures and flows and/or pipeline lengths are too short to feasibly run traditional in-line Inspection tools.

**29** Tensile stress is when equal and opposite forces are applied on a body, in this case a pipeline.

**30** See Leak Abatement OIR Decision (D). 17-06-015.

**31** 2017 GRC Exhibit (PG&E-3), Chapter 6C, page 6C-4, fn. 10, "It will never be possible to survey the entire system with the Picarro Surveyor due to Abnormal Operating Conditions (AOC) and physical conditions that lessen the coverage of the technology…" PG&E surveyed one hundred percent of its divisions with the technology in 2018 and in doing so it covered seventy-five percent of the distribution system.

**32** As of January 1, 2017, PG&E updated its leak grading procedure, TD-4110P-09, to include direction and definition from GO-112F, footage criteria from structures, criteria for leaks in SCADA cabinets, standby requirements, and remove Grade 2+ leak grading.

**33** In addition to Leak Survey recommendations, Rulemaking 15-01-008 includes acceleration of leak repairs.

**34** This number is the original target when CPSI was established in 2013.

**35** PG&E's California Gas Transmission Pipe Ranger website Supply and Demand Archives, https://www.pge.com/pipeline/operations/cgt_supplydemand_search.page. Execute search for 12/31/2019 and preceding 364 days, then add values listed in "Total System Supply" row.

**36** The GERP complies with CFR Title 49, Transportation, Part 192—Transportation of Natural and other Gas by Pipeline: Minimum Federal Safety Standards,

Section (§) 192.615, "Procedural manual for operations, maintenance, and emergencies" and (§)192.605 "Emergency Plans."

**37** ASME B31-Q.

**38** See Attachment 8.

**39** NACE, formerly known as the National Association of Corrosion Engineers, is an international organization focused on developing industry standards for corrosion management, teaching best practices, and researching corrosion issues. NACE provides multiple certificate programs in a variety of corrosion management areas.

**40** Created as part of Gas Stewardship and was formerly known as Super Gas Operations (SGO) and Process Excellence. The Lean Capability Center includes a select group of leaders from the organization to implement the Lean Management System in Gas Operations organization

**41** QM's findings are aligned with the Gas Operations CAP Risk Matrix and thus are defined based on risk level. Examples of high findings are findings determined to have potential risk of resulting in a serious injury or fatality, failure/damage/degradation to critical assets, or resulting in significant regulatory action.

# X. APPENDIX A – LIST OF FIGURES

## XI. APPENDIX B – LIST OF TABLES

## XII. APPENDIX C – LIST OF ATTACHMENTS

Attachment 1 – PG&E Corporation Safety and Nuclear Oversight Committee, Resolution of the Board of Directors of PG&E Corporation, September 19, 2017

Attachment 2 – 2018 Safety Committee Charter

Attachment 3 – Gas Safety Excellence Policy: TD-01, Rev. 2

Attachment 4 – Change Logs for PG&E's Asset Management Plans, Gas Emergency Response Plan, Company Emergency Response Plan, and Gas System Operations Control Room Management

Attachment 5 – Patrolling Gas Pipelines; Utility Procedure TD-4412P-07, Rev. 07

Attachment 6 – Job Site Safety Analysis Form (JSSA) for Tailboard Briefing TD-4414P-F01, Rev. 0

Attachment 7 – Change Log for 2019 Gas Safety Plan

Attachment 8 – Contractor Safety Oversight Procedure – Gas Operations Utility Procedure SAFE-3001P-07 Rev. 3

Attachment 9 – Station Critical Documentation; Utility Standard TD-4551S, Rev. 2

VERIFICATION

I, the undersigned, state:

I am an officer of PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, and am authorized to make this verification for and on behalf of said corporation, and I make this verification for that reason. I have read the foregoing 2019 Gas Safety Plan and I am informed and believe the matters therein are true and on that ground I allege that the matters stated therein are true.

I declare under penalty of perjury under the laws of the state of California that the foregoing is true and correct.

Executed at San Ramon, California, on March 1, 2019.

Jesus Soto, Jr.
SENIOR VICE PRESIDENT, GAS OPERATIONS
PACIFIC GAS AND ELECTRIC COMPANY

**PACIFIC GAS AND ELECTRIC COMPANY**

**ATTACHMENT 1**

**PG&E Corporation Safety and Nuclear Oversight Committee, Resolution of the Board of Directors of PG&E Corporation, September 19, 2017**

**PG&E Corporation Safety and Nuclear Oversight Committee**

**RESOLUTION OF THE**
**BOARD OF DIRECTORS OF**
**PG&E CORPORATION**

September 19, 2017

WHEREAS, in connection with the settlement resolving the consolidated shareholder derivative litigation seeking recovery on behalf of PG&E Corporation and Pacific Gas and Electric Company (the "Utility") (together, the "Companies" or "PG&E") for alleged breaches of fiduciary duty by certain current and former officers and directors, the Companies agreed to implement certain corporate governance therapeutics, including therapeutics relating to establishment of safety oversight committees of the Companies' respective Boards of Directors;

NOW, THEREFORE, BE IT RESOLVED that, effective immediately, the Nuclear, Operations, and Safety Committee of this Board of Directors is renamed as the Safety and Nuclear Oversight Committee; and

BE IT FURTHER RESOLVED that the Safety and Nuclear Oversight Committee shall consist of at least three directors, one of whom shall be appointed as the Committee's chair; and

BE IT FURTHER RESOLVED that all members of the Safety and Nuclear Oversight Committee shall satisfy independence and qualification criteria established by this Board of Directors, as set forth in this corporation's Corporate Governance Guidelines, and shall be "independent" as defined by standards established by any stock exchange on which securities of this corporation or the Utility are traded; and

BE IT FURTHER RESOLVED that the basic responsibility of the Safety and Nuclear Oversight Committee shall be to advise and assist this Board of Directors with respect to the oversight and review of (i) policies, practices, goals, issues, risks, and compliance relating to safety (including public and employee safety), and compliance issues related to PG&E's nuclear, generation, gas and electric transmission, and gas and electric distribution operations and facilities ("Operations and Facilities"), (ii) significant operational performance and other compliance issues related to such Operations and Facilities, and (iii) risk management policies

and practices related to such Operations and Facilities. This role is one of oversight and in no way alters management's authority, responsibility, or accountability. More specifically, with respect to such Operations and Facilities, the Safety and Nuclear Oversight Committee shall, among other things:

1. Review significant policies and issues related to safety, operational performance, and compliance.

2. Review with management the principal risks related to or arising out of PG&E's Operations and Facilities (including risks that are identified through PG&E's enterprise risk management program and that are selected in consultation with this Board of Directors and its committees, as applicable), and assess the effectiveness of PG&E's programs to manage or mitigate such risks, including with respect to:

   (a) the safe and reliable operation of any nuclear facilities owned by PG&E;

   (b) integrity management programs for PG&E's gas operations and facilities; and

   (c) asset management programs for PG&E's electric operations and facilities.

3. Review and discuss how PG&E can continue to improve its safety practices and operational performance.

4. Review and discuss the results of PG&E's goals, programs, policies, and practices with respect to promoting a strong safety culture.

5. Review the impact of significant changes in law and regulations affecting safety and operational performance.

6. Advise this corporation's Compensation Committee on appropriate safety and operational goals to be included in PG&E's executive compensation programs and plans.

7. Meet at least six times per year. Such meetings shall include at least semiannual joint meetings with the Utility's Safety and Nuclear Oversight Committee, this corporation's Audit Committee, the Utility's Audit Committee, and the corporation's Compliance and

Public Policy Committee to discuss PG&E's compliance program and any other topics agreed upon by those committees.

8. (a) Review the adequacy and direction of PG&E's corporate safety functions, including the appointment and replacement of any chief safety officer of this corporation (or any officer who is similarly given direct responsibility for overseeing enterprise-wide safety matters at the corporation) (the "Chief Safety Officer"), (b) review with the Chief Safety Officer the responsibilities, budget, and staffing of the corporation's safety function, (c) periodically review PG&E's corporate safety and health functions, goals, and objectives represented in PG&E's five-year planning process, and (d) periodically review reports provided to management by the Chief Safety Officer and any chief safety officer of the Utility (or any officer who has direct responsibility for overseeing safety matters at the Utility).

9. Serve as a channel of communication between the Chief Safety Officer and this Board of Directors.

10. Meet separately with the Chief Safety Officer from time to time, at the discretion of the Chair of the Committee.

11. Report regularly (and at least semiannually) to this Board of Directors on deliberations and actions taken by the Committee, and issues considered and addressed as part of the Committee's oversight responsibilities.

BE IT FURTHER RESOLVED that the members of the Safety and Nuclear Oversight Committee shall periodically visit PG&E's nuclear and other operating facilities; and

BE IT FURTHER RESOLVED that the Chief Safety Officer shall regularly provide reports to the Safety and Nuclear Oversight Committee regarding (1) the status of PG&E's policies, practices, standards, goals, issues, risks, and compliance relating to safety, (2) activities relating to creation and instillation of safety culture at PG&E, (3) activities relating to establishment of and performance on safety metrics, and (4) such other topics as may be requested by the Committee; and

BE IT FURTHER RESOLVED that this corporation's Chief Ethics and Compliance Officer shall regularly provide reports to the Safety and Nuclear Oversight

Committee regarding activities relating to establishment of and performance on compliance and ethics metrics related to PG&E's Operations and Facilities; and

BE IT FURTHER RESOLVED that the Safety and Nuclear Oversight Committee also may request reports from any member of senior management of PG&E, that such reports shall be provided within a reasonable time of the request, and that any dispute or unreasonable delay with respect to such a request shall be documented in the Committee's minutes; and

BE IT FURTHER RESOLVED that the Safety and Nuclear Oversight Committee shall be empowered to act independently of other committees of this Board of Directors and shall not be subject to direction or limitation by any other committee of this Board, subject to applicable legal restrictions and stock exchange standards; and

BE IT FURTHER RESOLVED that the Safety and Nuclear Oversight Committee shall fix its own time and place of meetings and shall, by a majority vote of its members, and subject to the California Corporations Code and this corporation's Articles of Incorporation and Bylaws, prescribe its own rules of procedure; and

BE IT FURTHER RESOLVED that the Safety and Nuclear Oversight Committee shall have the right to retain or utilize, at this corporation's expense, the services of such firms or persons, including independent counsel or other advisors, as the Committee deems necessary or desirable to assist it in exercising its duties and responsibilities; and

BE IT FURTHER RESOLVED that the Safety and Nuclear Oversight Committee shall have the right to request and receive from this Board of Directors reasonable resources to assist it in exercising its duties and responsibilities, and that such requests, and any failure to provide such requested resources, shall be documented and explained in the minutes of the Committee and this Board; and

BE IT FURTHER RESOLVED that, unless otherwise designated by the Committee, the Corporate Secretary of this corporation, or an Assistant Corporate Secretary, shall serve as secretary to the Safety and Nuclear Oversight Committee; and

BE IT FURTHER RESOLVED that the resolution on this subject adopted by the Board of Directors on May 31, 2017 is hereby superseded.

**PACIFIC GAS AND ELECTRIC COMPANY**

**ATTACHMENT 2**

# 2018 Safety Committee Charter

# 2018 Safety Committee Charter

**Standing Committee Directive:** Provide overall governance of safety; guide the enterprise safety strategy and philosophy; and assure continuous improvement of employee, contractor, and public safety performance. This Committee replaces the Chairman's Safety Council, the Safety Culture Steering Committee, and the ECAP Steering Committee.

**In scope:**

| Agenda Topic | Frequency | Desired Outcomes |
|---|---|---|
| SIF Actual or Potential | As necessary | Inform/Input – Report findings, review associated corrective actions, and share learnings from the event. |
| One PG&E Occupational Health and Safety Plan: Planning and Updates | Monthly | Inform/Input/Decide – Update plan status and request Committee input and/or decision as necessary. |
| External Safety and Health Updates | As necessary | Inform/Input/Decide – Inform committee of external and industry health and safety related trends and developments. |
| BPR Follow-ups or Deep Dives | As necessary | Inform/Input – Resolution of questions that arise from safety effectiveness review during BPR. |
| ECAP Updates | Quarterly | Inform/Input/Decide – Update project status and request Committee input and/or decision as necessary. |
| LOB Safety Council Updates | Monthly | Inform/Input – Relevant topics from the LOB. |
| Labor Updates | Monthly | Inform/Input – Relevant topics from the union representatives. |
| DOT Updates | As necessary | Inform/Input/Decide – Update project status and request Committee input and/or decision as necessary. |
| Contractor Variance Requests | As necessary | Decide – Review and approve contractor variance requests |

**Attendees:**

- Chair: John Simon, Vice Chair: Jon Franke
- Coordinator(s): Alisa Okelo-Odongo
- Members: Todd Hohn, Kathy Kay, Michael Lewis, Jesus Soto, Julie Kane, Laurie Giammona, Jim Welsch, Tom French, Mel Christopher, Scott Sanford, Andy Williams, Gun Shim, Sumeet Singh
- Union Members: Karen Sawislak, Tom Dalzell

**How decisions are made:**

- Decisions will be made by the Safety Committee Chair, with input from committee members

**Meeting logistics:**

Two meetings per month:

- 1st meeting:
  - Cadence: Twice per month
  - Duration: ½ Hour
  - Attendees: Michael Lewis, Jesus Soto, Todd Hohn, Gregg Lemler, Jim Welsch, Mel Christopher, Scott Sanford, Andy Williams, Gun Shim, Sumeet Singh, Alisa Okelo-Odongo, Rudy Wolf, Kcammee Vreman
- 2nd Meeting:
  - Cadence: Once per month, fourth week of the month
  - Duration: 2 Hours
  - Attendees: John Simon, Jon Franke, Todd Hohn, Kathy Kay, Michael Lewis, Jesus Soto, Julie Kane, Laurie Giammona, Jim Welsch, Tom French, Mel Christopher, Scott Sanford, Andy Williams, Gun Shim, Sumeet Singh, Alisa Okelo-Odongo, and Union Members
- Agenda Creation: Coordinator will work with the Chair and Committee members

**BOD Committee supported:**

- Safety and Nuclear Oversight Committee

**PACIFIC GAS AND ELECTRIC COMPANY**

**ATTACHMENT 3**

**Gas Safety Excellence Policy: TD-01, Rev. 2**

Pacific Gas and Electric Company®

# Gas Operations Policy: TD-01

Revision 2
Publication Date: 07/18/2018
Effective Date: 08/01/2018

## Gas Safety Excellence

**Policy Statement:**

Pacific Gas and Electric Company (PG&E or Company) is committed to the safe, reliable, affordable, and clean operation and management of its gas transmission and distribution system for its employees, contractors, customers, and the public. Gas Operations has developed a safety management system, Gas Safety Excellence (GSE), which is based on three pillars: Asset Management, Safety Culture, and Process Safety. This system complies with:

- Corporate Policy SAFE-01, “Enterprise Safety Management System Policy”
- PAS 55/ISO 55001, industry-recognized standards for asset management
- The American Petroleum Institute (API) Recommended Practice (API RP) 1173 specification for pipeline safety management
- The American Chemistry Council’s Responsible Care Management System Certification, RC14001, a global standard combining the elements of ISO 14001 and Responsible Care’s guiding principles, associated with improving process safety and impact on the environment, health, safety and security (EHS&S)

This safety management system helps to proactively manage PG&E’s safety culture, the condition of gas assets, the identification and reduction of operational and enterprise risk, and the continued support of processes and procedures related to process safety, employee and contractor safety, security, communications, emergency response, and environmental stewardship.

This framework includes the following operating principles, aspirations, approach, and expectations:

- Fostering a “safety first” culture where employees and contractors understand the vision, strategic plans, and the role they play in meeting PG&E’s objectives
- Creating an environment where employees and contractors feel empowered to report and raise safety and compliance issues by using a non-punitive, self-reporting corrective action system, or other means
- Understanding the criticality and condition of assets, mitigating associated risks, and managing system performance at an affordable cost over the life cycle of gas assets
- Complying with legal, regulatory, and other requirements, including applicable EHS&S laws and regulations through systems to identify these requirements, determine applicability, implement programs, and assess compliance
- Applying asset management and process safety principles to manage assets throughout their life cycle to protect employees, contractors, the public, the environment, and property

- Implementing proactive environmental stewardship and protection with the intent of reducing methane emissions and preventing other pollution to preserve the environment for the health, productivity, and enjoyment of future generations
- Communicating our business operations and potential risks, both internally and externally, to promote openness and transparency with our stakeholders
- Maintaining and making accessible to all relevant users accurate, traceable, verifiable, and complete asset information, including all data and records
- Maintaining up-to-date documentation (such as standards, procedures, and as-built documents) to manage gas assets throughout their life cycle, and ensuring updates to documentation are effectively communicated
- Verifying that employees, contractors, and subcontractors are competent, trained, and qualified to design, construct, manage, operate, maintain, and retire assets, and that they understand their critical role in applying our safety management system
- Assessing and managing all major changes to assets, processes, organizations, and technologies to manage risk and deliver safe, reliable, affordable, and clean service
- Establishing and maintaining appropriate Key Performance Indicators that measure progress against line-of-sight goals
- Investigating and analyzing safety-related incidents to determine root causes, developing corrective actions, and conducting quality reviews as appropriate
- Regularly benchmarking the safety management system performance internally and externally, and using the findings for continual improvement
- Maintaining the safety management system in accordance with SAFE-01, PAS 55, ISO 55001, API RP 1173, and RC14001

This policy directs PG&E Gas Operations to develop and maintain a safety management system aligned with the requirements of all elements of GSE (including PAS 55, ISO 55001, API RP 1173, and RC14001 standards), and to continually review and improve this system to assure that it remains suitable, adequate, and effective. In addition, this policy provides the structure to continue our journey to becoming the safest, most reliable, affordable, and cleanest gas company in the nation.

**Target Audience:**

This policy applies to PG&E employees and contractors who work on or with PG&E gas assets and associated control systems

**Accountability:**

The Director of Safety, Quality and Contracts Management is responsible for updating and monitoring compliance with this policy.

Pacific Gas and Electric Company®

# Gas Operations Policy: TD-01

Revision 2
Publication Date: 07/18/2018
Effective Date: 08/01/2018

**Approval:**

| | |
|---|---|
| **Key Contacts:** | Kcammee Vreman, Director, Gas Operations Safety, Quality and Contracts Management |
| **Reviewed by:** | Sumeet Singh, Vice President, Gas Operations Portfolio Management and Engineering<br>Andrew Williams, Vice President, Land and Environmental Management<br>John Higgins, Vice President, Safety and Health<br>Christine Cowsert, Sr. Director, Gas Operations Asset Management and System Operations |
| **Sponsoring Officer:** | Jesus Soto Jr., Senior Vice President, Gas Operations |
| **Final Review by Compliance and Ethics:** | Julie Kane, Senior Vice President, Compliance and Ethics |
| **Approved by:** | Jesus Soto Jr., Senior Vice President, Gas Operations |
| **Effective Date:** | 08/01/2018 |
| **Scheduled Review:** | 07/18/2019 |

**Policy Revision History:**

| Where | What Changed |
|---|---|
| Entire document | New policy combining TD-01, “Gas Asset Management Policy,” and TD-03, “Responsible Care Policy.” |

**PACIFIC GAS AND ELECTRIC COMPANY**

**ATTACHMENT 4**

# Change Logs for PG&E's Asset Management Plans, Gas Emergency Response Plan, Company Emergency Response Plan, and Gas System Operations Control Room Management

# 2019 Gas Safety Plan – Attachment 4

| Document No. | Change Log Name | Rev. | Attachment Page No. (ATCH) |
|---|---|---|---|
| GP-1100 | Strategic Asset Management Plan | 4 | 4-1 |
| GP-1108 | Gas Storage Asset Management Plan | 5 | 4-2 |
| GP-1105 | Compression & Processing Asset Management Plan | 5 | 4-4 |
| GP-1101 | Transmission Pipe Asset Management Plan | 5 | 4-5 |
| GP-1104 | Measurement & Control Asset Management Plan | 5 | 4-6 |
| GP-1102 | Distribution Mains and Services Asset Management Plan | 5 | 4-7 |
| GP-1103 | Customer Connected Equipment Asset Management Plan | 5 | 4-8 |
| GP-1106 | LNG/CNG Portable Supply Asset Management Plan | 4 | 4-9 |
| GP-1107 | CNG Station Asset Management Plan | 4 | 4-10 |
| EMER-3003M | Gas Emergency Response Plan – Gas Annex to the CERP PG&E | 8.0 | 4-11 |
| EMER-3001M | Company Emergency Response Plan (CERP) | 4.2 | 4-18 |
| TD-4436S | Minor Revision Guidance Document Analysis (GDA) Gas System Operations Control Room Management | 8a | 4-28 |

## A. Change Log

The following table summarizes revisions since the previous publication of GP-1100: Asset Management Strategy & Objectives, Revision 4, 8/1/2017.

**Table 5 – Strategic Asset Management Plan Change Log**

| Section | Change | Reason for Change | Implication of Change |
|---|---|---|---|
| 1, 2.5, 3.1 | Updated references to PG&E Mission and Gas Operations Line of Sight Goals | Updated content to reflect latest changes in the business | Ensure change is communicated with stakeholders |
| 1 | Removed Executive Summary; content incorporated in Introduction and other relevant sections | Consistency with asset family asset management plan revisions | Ensure change is communicated to stakeholders |
| 2.3 | Condensed section on data | Information on work ongoing to manage data as an asset will be addressed in a separate document | Ensure change is communicated to stakeholders |
| 3.2 | Modified content on self-assessment | To align with self-assessment cycle and accurately represent activities | Ensure change is communicated to stakeholders |
| 3.3 | Removed references to specific regulations | Information may be change more rapidly than StAMP revision cycle; contact Regulatory Compliance for additional information | Ensure change is communicated to stakeholders |
| 4 | Updated roles and responsibilities | Revised roles and responsibilities to reflect organizational changes in business | Ensure individuals with specified roles and responsibilities are aware of changes |
| 5 | Revised continual improvement items | Updates are based on the most recent self-assessment performed against PAS 55 and ISO 55001 standards | Ensure change is communicated to stakeholders |
| Appendix B | Added additional Related Documents | Changes to Related Documents available | Ensure change is communicated to stakeholders |
| Appendix C | Revised content on Asset Management Plan structure | Updated information based on AMPs | Ensure change is communicated to stakeholders |

## G. Change Log

The following table summarizes revisions since the previous publication of GP-1108: Gas Storage Asset Management Plan, Revision 4, August 2018.

**Table 27 - Asset Management Plan Change Log**

| Section | Change | Reason for Change | Implication of Change |
|---|---|---|---|
| 1 | Added paragraph on NGSS and updated regulations | Updated to reflect new DOGGR and PHMSA regulations | None |
| Table 2 | Updated for revised operational statistics | To correctly reflect operational values | None |
| Table 4 | Condensed well count table | Adds clarity to presentation of data | None |
| 2.2.2 Production Casing | Expanded description of integrity assessments | Provide context on reason for performing all the tests. | None |
| 2.2.2 Sand Inspections | Updated analysis discussion and trend chart with current data for sand inspection results | Update data presented | None |
| 2.2.4 Surface Equipment | Updated analysis discussion and trend charts with current data and impacts of new regulations | Update data presented | None |
| 2.2.5 | Updated discussion regarding current leak survey practices and findings | Update data presented | None |
| 3.0 | Updated enterprise risk and added language to reflect alignment of Session D, RAMP and Risk Register | Update to risk alignments | None |
| Figure 5 | Updated Gas Ops Risk Profile chart | Reflect new rankings of Storage asset family risks relative to gas operations risks | None |
| 3.1.2 | Added table showing the risks that have been combined with Transmission and C&P | Summary of risk re-alignment | None |
| 3.1.2 | Added discussion regarding change to rollup risk structure for storage. | Provide background to grouping risks into rollup categories based on asset type failure and summarizes the changes to the risk register | None |
| Figure 7 | Updated Gas Ops Risk Profile chart | Reflect new rankings of Storage asset family risks relative to gas operations risks | None |

| Section | Change | Reason for Change | Implication of Change |
|---|---|---|---|
| Table 14 | Updated Key Risks Table to reflect latest from risk register and included previous highest risk with their new designation under TIMP and C&P | Reflect current ranking of risks in storage ask family | None |
| 3.2 | Added footnote to call out alignment to new regulations | Updated to be relevant for current environment | None |
| Table 15 | Strategic Objectives Updated | Reflects updates based on changes in regulatory environment | None |
| 4 | Added section regarding the Natural Gas Storage Strategy (NGSS) filed in the 2019 GT&S and updated section on Regulatory and Legislative Impact on Storage Assets to reflect issuance of DOGGR final regulations on 6/28/18 | Provide background and set stage for change into how assets in the storage family will be managed going forward due to the new DOGGR regulations. | None |
| 4.2 Programs and Mitigations Overview | Updated tables 17, 18, 19 and 20 to reflect proper responsibilities owner and updated risk id's to reflect changes to the risk register | Update data presented | None |
| 5 | Areas for continuous Improvement updated | Updated for current outlook | None |
| Appendix C | Updated Table 23 for 2018 risk register risks | Alignment with current review period | None |
| Appendix F | Updated with two new acronyms | Update data presented | None |
| Appendix I | Updated R&S project table and relabeled as appendix H | Updated to reflect current, completed, and planned R&D projects. | None |
| Appendix H | Removed Appendix on Asset Health score card | Need to re-do to align with the new regulations. Currently analyzing the new regulations | None |
| Appendix J | Removed Appendix J - Roadmap | NGSS long term strategy in being reviewed in light of new DOGGR regulations, so more time is needed to decide on the long term plan. | None |

## F. Change Log

The following table summarizes revisions since the previous publication of GP-1105: Compression & Processing Asset Management Plan, Revision 3, 8/1/2016.

**Table 19 – Asset Management Plan Change Log**

| Section | Change | Reason for Change | Implication of Change |
|---|---|---|---|
| Entire Asset Management Plan | Update to previous version of Asset Management Plan dated August 1, 2017 | Updated information regarding fleet of C&P assets; condition of C&P assets; risks associated with C&P assets; mitigations associated with risks to C&P assets; and continuous improvement activities associated with C&P assets | Updated information |
| Section 4.1 | Revised Strategic Objectives; removed objective related long-term compression investment plan; modified target for objective related to unscheduled shutdowns. | Long-term compression investment plan is now integrated as on-going activity within FIMP; revised unscheduled shutdown target to more accurately align with goal. | Strategic objectives more accurately represent on-going activities and targets |
| Section 5 | Changes and updates to areas of continuous improvement | Updated continuous improvements list to reflect 2017-2018 activities and goals. | Updated information |
| Appendix H | Updated Compressor Dashboard figures and updated availability and reliability charts to show 2017 data | Updated information due to dashboard improvements | Updated information |

## G. Change Log

The following Table 19 summarizes revisions since the previous publication of GP-1101: Transmission Pipe Asset Management Plan, Revision 4, which was published August 2017.

**Table 19 – Asset Management Plan Change Log**

| Section | Change | Reason for Change | Implication of Change |
|---|---|---|---|
| Entire Asset Management Plan | Updated asset family statistics, tables and figures | Annual data update | Improved asset knowledge |
| Section 2 | Added sections 2.2.6-11 | Included additional asset condition metrics | Expanded asset condition knowledge |
| Section 3.1, Appendix C | Update list to reflect 2018 Session D risk ranks | Merged 7 storage risks | Merged storage risks to align with RAMP |
| Section 4 | Removed reference to reduce medium risk operations in the system capacity strategic objective | May strategically leverage medium risk operations (portable supply equipment) | None |
| Section 4 | Added table to better display long-term goals | Improved alignment between strategic objectives and long-term goals | None |
| Section 4.2 | Updated programs and mitigations | Annual update | None |
| Section 5 | Update | Annual update | None |
| Appendix B | Update | Annual update | None |
| Appendix C | Update | Updated threat descriptions and notes | Merged storage risks to align with RAMP |
| Appendix D | Stakeholder roles and responsibilities matrix | Updated stakeholder group names to reflect current organizational structure | None |
| Appendix H | Removed Appendix H, relabeled Appendix I to H. | Session D summary content was outdated.<br>Annual update | None |

## F. Change Log

The following table summarizes revisions since the previous publication of GP-1104: Measurement & Control Asset Management Plan, Revision 4, August 2017.

**Table 14 – Asset Management Plan Change Log**

| Section | Change | Reason for Change | Implication of Change |
|---|---|---|---|
| Entire Asset Management Plan | Update to previous version of Asset Management Plan dated August 1, 2017 | Updated information regarding fleet of M&C assets; risks associated with M&C assets; mitigations associated with risks to M&C assets; and continuous improvement activities associated with M&C assets | Updated information |
| Section 4 | Update section titled “FIMP Maturity Model” with current information. | Consistency with current FIMP model information | Updated information |
| Section 4 | Added new content on Overpressure Elimination Initiative | Additional key information on M&C asset family activities | Updated information |
| Section 4, Table 6 | Update Table 6 with updated strategic objectives | Consistency with current strategic objectives | Updated information |
| Section 4, Table 7 | Update Table 7 with updated strategic objectives and updated programs (from current GT&S) | Consistency with current programs | Updated information |
| Section 4, Table 8 | Update Table 8 with updated programs (from current GT&S) | Consistency with current programs | Updated information |
| Appendix B | Update with new threat matrices | Consistency with current risk register and other FIMP information | Updated information |
| Appendix C | Updated based on current risk register | Consistency with current risk register information | Updated information |
| General | Updated of Figure and Table numbers based on overall revisions to the document | Based on deleted / added figures throughout the document | Updated information |

## F. Change Log

The following table summarizes revisions to the publication of the GP-1102: DMS Asset Management Plan, Revision 4, August 2017.

**Table 16 - Asset Management Plan Change Log**

| Section | Change | Reason for Change | Implication of Change |
|---|---|---|---|
| Entire Asset Management Plan | Updated charts and tables | Updated with current data | None |
| Section 2 | Updated asset type descriptions distribution main and service | Updated to align with definitions in TD-4125P-10 | None |
| Section 2 | Removed SCADA asset type | SCADA assets covered in GP-1104 | None |
| Section 3 | Updated Table 4 – Enterprise Risk for Distribution Mains and Services Asset Family | DMS001 is now considered as the Enterprise Risk | None |
| Section 4 | Strategic Objectives | Added two Strategic Objectives approved in the Risk and Compliance Committee meeting on 5-18-18:<br>Safe and Reliable: Identify preferred fusion methods and align procedures with industry by 2022<br>Safe and Reliable:<br>Improve supply chain reliability by 2022 | None |
| Appendix C | Asset Family Risks | Risk Scores and risk ranking updated to align with 2018 Risk Register Refresh | None |

## G. Change Log

The following table summarizes revisions since the previous publication of GP-1103: Customer Connected Equipment Asset Management Plan, Revision 4, August 2017.

**Table 13 - Asset Management Plan Change Log**

| Section | Change | Reason for Change | Implication of Change |
|---|---|---|---|
| Entire Asset Management Plan | Updated charts and tables | Updated with current data | None |
| Section 4 | Strategic Objectives | Refined strategic objective for Smart Meter Next Generation and added a metric for this objective | Improved understanding of safety features to be added to future meter design |
| Appendix C | Revised Asset Family Risks | Risk scores and risk ranking updated to align with 2018 Risk Register Refresh | None |
| Appendix D | Stakeholder Roles and Responsibilities Matrix | Updated stakeholder group names to reflect changes to the organizational structure | None |

## G Change Log

The following table summarizes revisions since the previous publication of this AMP in 2017.

**Table 17 - Changes to the August 2018 Edition**

| Section | Change | Reason for Change | Implication of Change |
|---|---|---|---|
| Entire Asset Management Plan | Updated asset family statistics, tables and figures | Annual data update. | Improved asset knowledge and changes in assets |
| Scn 2.2.1 | Updated asset condition summary | Better understanding, new assets | More complete information |
| Scn 3 | Updated risk score histogram | Updated to reflect annual risk refresh process results | Current information |
| Scn 3.2 | Updated FIMP and graphic that describes | Updated to reflect changes to LNG/CNG FIMP as a result of C&P AF FMIP design | Current information |
| Scn 4.1 | Updated strategic objectives | Updated to reflect revisions made to AF strategic objectives | Current information. Better description of business objectives |
| Scn 4.2 | Updated desired state and some scope items to better align with updated strategic objectives | Updated to reflect revisions made to AF strategic objectives and programs | Current information. Better description of business objectives |
| Scn 5 | Added accomplishments summary and expanded areas for continuous improvement | Revised to improve consistency with other AMPs | Better consistency |
| Apdx B | Updated treat matrix | New matrix since last year | Current information |
| Apdx H | Updated obsolescence management graphic / plan | Revised plan since last year | Current information |
| Apdx I | Updated with new assets | Added assets | Current information |
| Apdx J | Added new | Improve consistency of Scn 3 with other AMPs | Better consistency and more comprehensive process description. |
| Apdx K | Added new | Improve consistency of Apdx A, and to capture those documents that were removed from A | Better consistency and more comprehensive list |

## G Change Log

The following table summarizes revisions since the previous publication of this AMP in 2018.

**Table 17 - Changes to the August 2018 Edition**

| Section | Change | Reason for Change | Implication of Change |
|---|---|---|---|
| Entire Asset Management Plan | Updated asset family statistics, tables and figures | Annual data update. | Improved asset knowledge and changes in assets |
| Scn 2.2.1 | Updated asset condition summary | Better understanding, new assets | More complete information |
| Scn 3 | Updated risk score histogram | Updated to reflect annual risk refresh process results | Current information |
| Scn 3.2 | Updated FIMP and graphic that describes | Updated to reflect changes to LNG/CNG FIMP as a result of C&P AF FMIP design | Current information |
| Scn 4.1 | Updated strategic objectives | Updated to reflect revisions made to AF strategic objectives | Current information. Better description of business objectives |
| Scn 4.2 | Updated desired state and some scope items to better align with updated strategic objectives | Updated to reflect revisions made to AF strategic objectives and programs | Current information. Better description of business objectives |
| Scn 5 | Added accomplishments summary and expanded areas for continuous improvement | Revised to improve consistency with other AMPs | Better consistency |
| Apdx B | Updated treat matrix | New matrix since last year | Current information |
| Apdx H | Updated obsolescence management graphic / plan | Revised plan since last year | Current information |
| Apdx I | Updated with new assets | Added assets | Current information |
| Apdx J | Added new | Improve consistency of Scn 3 with other AMPs | Better consistency and more comprehensive process description. |
| Apdx K | Added new | Improve consistency of Apdx A, and to capture those documents that were removed from A | Better consistency and more comprehensive list |

# Significant Changes

The updates to Gas Emergency Response Plan (GERP) Revision 8.0 focuses on the most significant changes and updates to content since the Plan's inception. Changes include the following items:

- Revised Response Aids for Wildfire
- Revised Response Aids for Gas Storage Incidents

# Document Record

This section contains Pacific Gas and Electric Company (Company or PG&E) legal notices and trademarks, as well as provides information related to the ownership and maintenance of this document.

## Document Control

Gas Emergency Preparedness (GEP), part of Gas System Operations (GSO), maintains the GERP – Gas Annex to the Company Emergency Response Plan (CERP). This section records the revisions made to the GERP (the GERP or the Plan), the responsible persons for its preparation, maintenance, and update; and signature authorities for Plan approval.

## Change Record

The following table shows changes made to the Plan since the last revision (Version 7, December 31, 2017). For content appearing in Version 7 and removed from this current revision, “(Revision 8)” has been added to the applicable entries. The table lists where the changes occurred, and what changes were made. The effective date is 12/31/2018.

| Where? | What Changed? | Who Initiated the Change? |
|---|---|---|
| Throughout | Updated department names as needed due to organizational changes | Various |
| Throughout | Updated Links as needed | Various |
| 1.1 | Updated "outside organizations" to "external organizations." | GEP |
| 1.3 | Removed reference to Section 3, “Core Capabilities,” and Section 6, “Training and Exercise.” These sections now reside in an internal GEP document. | GEP |
| 1.3.2 | Added Table 1, “Transmission District Headquarters and Gas Storage Facility Locations for GERP Distributon and Where Physical Copies of the GERP Must Be Kept.” | GEP |

| Where? | What Changed? | Who Initiated the Change? |
|---|---|---|
| 1.5 | Added reference to California Public Utilities Code 956/956.5, California Air Resource Board regulations, Division of Oil, Gas, and Geothermal Resources (DOGGR) regulations, California Code of Regulations Title 14, Division 2, Chapter 4, the Pipeline and Hazardous Materials Safety Administration (PHMSA) Interim Final Rule (IFR), and Utility Standard EMER-1001S, “Business Continuity Planning Training, Exercise and Improvement Planning Standard.” | GEP |
| 1.6.1 | Clarified content and added information in regard to the IC Advisors for the GEC teams. Updated Figure 1.3. | GEP |
| 1.6.2 | Moved information from former Section 6, “Training and Exercise Activities,” to this section. Deleted former Section 6 which duplicated training and exercise information. | GEP |
| 1.6.3 | Relocated content from former Section 6. | GEP |
| 1.7.1 | Updated Table 1.2, “Gas Mission-Critical Processes for 2019,” to remove processes that are no longer mission-critical (core gas supply, gas wholesale marketing, and business development) | GEP |
| 1.7.3.1 | Updated Table 1.3, “2018 Gas Session D Risks.” | Bhavini Shah |
| 1.7.4 | Updated links in Table 1.4, “Incident Response Planning Documents.” | Gas System Planning |
| 2.2 | Removed organizational chart due to constant changes. | All |
| 2.3 | Updated number of distribution regions from 2 to 4. | All |
| 2.3.1.1 | Clarified language about contact center involvement in emergency response. | Andrea Tau<br>Kellie Dion<br>Heather Herrera |

| Where? | What Changed? | Who Initiated the Change? |
|---|---|---|
| 2.3.1.5.1 | New section added to address CAP #112848069 - Picarro Dispatch process/triggers for use. | Ty Turner<br>Erik Kurtz<br>Kelly Ball |
| 2.3.1.7.4 | Clarified DiRT team's role. | Jorge Gil-Blanco<br>Dane Lobb |
| 2.3.2.1 | Added measurement and control team information from Section 2.3.2.2. | Ben Campbell |
| 2.3.2.2 | Moved measurement and control team information to Section 2.3.2.1. | Josh Kirtley |
| 2.3.2.4 | Changed “1 to 2” hours to “3 to 4” hours for response time. | Steve Sheridan |
| 2.3.3 | Updated Table 2.4, “PG&E Teams Working Closely with AMSO,” due to organizational changes. | Raymond Theirry |
| 2.3.4 | Removed due to organizational changes. | All |
| 2.3.4.1 | Removed due to organizational changes. | All |
| 2.3.5 | Updated Gas Storage Facilities Map. | Larry Kennedy - Wild Well |
| 2.4.1.1 | Updated organization name to Environmental Management and Programs. | Steve Ferrara |
| 2.4.2 | Added bullet: Facilitates the creation of the CEMA incident SharePoint repository for source document retention (i.e., timecards, mutual aid contracts, material records, employee expense receipts. | Paul Lutich |
| 2.5 | Updated section title to “Safety and Corporate Security.” | John Gilginas<br>Cathy Kawachi |
| 2.7.1.1.1 | Simplified language describing distribution system and associated SCADA due to number of SCADA devices changing. | Kari Kotula |
| 2.7.1.1.2 | Simplified language describing SCADA due to number of SCADA devices changing. | Kari Kotula |

| Where? | What Changed? | Who Initiated the Change? |
|---|---|---|
| 3.1 | Updated references of Incident Level “examples” to “triggers.” | GEP |
| 3.1.1 | Revised gas storage triggers to match WCTC. | GEP |
| 3.1.2 | Added clarification that incident level matrix is not all inclusive and does not replace judgement from incident commanders or emergency center commanders. Updated matrix to clarify customer calls trigger, odorant equipment trigger, wildfire trigger, and storage triggers per WCTC. | GEP |
| 3.2.1.3.1 | Added two bullets list of make safe actions of the GSRs: Shutting off gas service at meter or curb valves and evacuating buildings and premises. | Matt Ramirez |
| 3.2.3.2.2 | Removed section “Field Personnel,” because it’s covered in Section 2. | All |
| 3.2.3.2.7 | Updated Figure 3.10, “FRCS Emergency Gas Shutdown and Restoration,” to latest version in Field Services handbook. | Richard Jennings |
| 3.2.4.3.1 | Updated Figure 3.14, “OEC Locations.” Added reference to Position Specific Roles and Responsibilities Documents. | GEP |
| 3.2.4.3.3 | Added reference to Position Specific Roles and Responsibilities Documents. | GEP |
| 3.2.4.3.5 | Added clarification on EOC support from Gas when gas emergency centers are not activated. | GEP |
| 3.2.5.3 | Removed GEC team details. This information is already captured in the GEC section. | GEP |
| 3.2.6.3.3 | Removed specific other weather related plan references due to ongoing CERP changes and now directs readers to the CERP. | GEP |

| Where? | What Changed? | Who Initiated the Change? |
|---|---|---|
| 3.2.8 | Additional content added to clarify deactivation vs. demobilization to address CAP #114122842. | GEP |
| 3.2.9 | New section, “Plan Deactivation/Deactivation of Emergency Centers,” added to address CAP #114122842. | GEP |
| 4.2.1.2 | Updated department name. | Scott Strenfel |
| 4.2.1.3 | Updated DASH response benefits. | Bronson Ingemansson |
| 4.2.2 | Gas Incident Report Example updated | GEP<br>Kari Kotula |
| 4.2.3 | Added reference and definition for Emergency Management Tool; changed MapGuide to GDGIS. | GEP<br>Bryan Hennessy |
| Section 5 | Removed Section “Core Capabilities.” Information is now in MYTEP internal GEP document. | GEP |
| Section 6 | Removed Section “Training and Exercise Activities”. Information was incorporated in other sections and in EMER-6010S. | GP |
| 7.1 | Now Section 5.1. | GEP |
| 7.2 | Now Section 5.2. Clarified records management, including physical and electronic versions. | GEP<br>LaTasha Jackson |
| 7.2.1 | Now Section 5.2.1. Simplified legal hold section to remove law department’s entire internal process, which is documented elsewhere. | GEP<br>LaTasha Jackson |
| 7.2.2 | Now Section 5.2.2. Removed entire section. Resources vary depending on incident. | GEP<br>LaTasha Jackson |
| 7.3 | Now Section 5.3. | GEP<br>LaTasha Jackson |

| Where? | What Changed? | Who Initiated the Change? |
|---|---|---|
| Appendix B | Added "consider requesting Picarro Dispatch" for Leak and Odor Investigation (CAP #112848069). Added "determine if leak survey needed" for Low Pressure/No Gas. Added clarification on inspection for cause of condition in Low/No Pressure. Added detailed assessment, notification, and reference document information for over pressurization and water in low pressure situations. | GEP |
| Appendix E | “Nurse Report Line” updated to "Nurse Care Line." | John Gilginas |
| Response Aids | Revised Response Aids for Wildfire. | Erik Moyer |
| Response Aids | Revised Response Aids for Gas Storage Incidents. | Brad Carr<br>Erik Moyer |

# Appendix K. Change Record

Changes made to the 2018 plan from the 2017 revision are noted in the table below.

| 2018 Section | 2018 Table of Contents | 2017 Section | 2017 Table of Contents | Clarification | Change Detail | Recommended By |
|---|---|---|---|---|---|---|
| 7.4 | United States Federal Government | 9.4 | United States Federal Government | Update in CERP Version 4.2 | Added CPUC Decision 18-08-004 requiring Emergency Consumer Protections for customers during states of emergency | Emily Behr |
| Throughout | | | | Clarification | Changed REC to Electric REC | Heather Martinez |
| Throughout | | | | Clarification | Changed Energy Supply to read Power Generation for all hydro and fossil references due to PG&E reorganization | Meg Richardson |
| Throughout | | | | Clarification | Changed Energy Supply to read Nuclear for all nuclear references due to PG&E reorganization | Tracey Vardas |
| Throughout | | | | Updated | Links validated | Aimee Felker |
| Throughout | | | | Edits | Minor edits of punctuation, spelling and/or wording to add clarity or correction | Aimee Felker, Laura Nixon |
| Throughout | | | | Organizational Names Updated | Organizational names changed to reflect 2018 PG&E structure, e.g., Energy Supply to Power Generation and/or Nuclear due to PG&E reorganization, and STOEC to Substation Emergency Center / T-Line Emergency Center (SubEC/TLEC) | |
| DP.2 | Document Preparer | DP.2 | Document Preparer | Updated | Updated to reflect 2018 status | Aimee Felker |
| DP.3 | Document Reviewers | DP.3 | Document Reviewers | Updated | Updated to reflect 2018 status | Aimee Felker |
| DP.4 | Change Record | DP.4 | Change Record | Updated | Updated to reflect 2018 status | Aimee Felker |
| | Change Request Form | | Change Request Form | Updated | Updated to reflect 2018 status | Aimee Felker |
| 1.5 | Document Organization | 1.5 | Document Organization | Minor | Updated to reflect 2018 status | Aimee Felker |
| 1.5.1 | CERP Annexes | 1.6.1 | CERP Annexes | Minor | Updated to reflect 2018 status | Aimee Felker |
| 1.6 | Plan Maintenance | 1.6 | CERP Base Plan | Minor | Updated to reflect 2018 status | Aimee Felker |
| 1.7 | Regulations and Authorities | 1.8 | Regulations and Authorities | Updated | Links validated | Aimee Felker, Sid Dietz, Heather Martinez |

| 2018 Section | 2018 Table of Contents | 2017 Section | 2017 Table of Contents | Clarification | Change Detail | Recommended By |
|---|---|---|---|---|---|---|
| 2.1 | Territory | 2.1 | Territory | Updated | Information validated and updated to reflect current public website data | Teresa Young, Tamyra Walz, Meg Richardson, Aimee Felker |
| 2.2 | PG&E Organizational Structure | 2.2 | PG&E Organizational Structure | Updated | Updated to reflect 2018 status | Aimee Felker, Tamyra Walz |
| 2.3 | PG&E Operational Structure | 2.3 | PG&E Operational Structure | Updated | Updated to reflect 2018 status | Aimee Felker |
| 2.3.1 | Electric Operations | 2.3.1 | Electric Operations | Updated | Updated to reflect 2018 status | Aimee Felker, Karen Schneeman, Laurie Jones |
| 2.3.2 | Gas Operations | 2.3.2 | Gas Operations | Updated | Updated to reflect 2018 status | Aimee Felker, Heather Martinez |
| 2.3.3 | Energy Supply | 2.3.3 | Energy Supply | Updated | Updated to reflect 2018 status | Aimee Felker, Meg Richardson |
| 2.3.4 | Nuclear | 2.3.4 | Nuclear | Updated | Updated to reflect 2018 status | Aimee Felker, Tracey Vardas |
| 2.5.1 | Emergency Preparedness & Response | 5.1 | Emergency Preparedness & Response | Minor | Updated to reflect 2018 status | Aimee Felker |
| 2.5.2 | Emergency Organization and Responsibilities | 5.2 | Electric Emergency Management | Minor | Updated to reflect 2018 status | Aimee Felker |
| 2.5.3 | Gas Emergency Preparedness | 5.3 | Gas Emergency Planning Team | Updated | Updated to reflect 2018 status | Heather Martinez |
| 2.5.4 | Diablo Canyon Power Plant (DCPP) Emergency Preparedness | 5.4 | Diablo Canyon Power Plant (DCPP) Emergency Preparedness | Minor | Updated to reflect 2018 status | Aimee Felker |
| 2.5.5 | Power Generation Emergency Preparedness | 5.5 | Power Generation Emergency Preparedness | Minor | Updated to reflect 2018 status | Aimee Felker |
| 2.6 | PG&E Emergency Management Organization (EMO) | 6 | PG&E Emergency Management Organization (EMO) | Minor | Updated to reflect 2018 status | Aimee Felker |

| 2018 Section | 2018 Table of Contents | 2017 Section | 2017 Table of Contents | Clarification | Change Detail | Recommended By |
|---|---|---|---|---|---|---|
| 2.6.1 | Corporate Incident Management Council (CIMC) | 6.1 | Corporate Incident Management Council (CIMC) | Minor | Proposed updates to reflect 2018 corporate structure | Aimee Felker |
| 2.6.2 | Incident Management Teams (IMTs) | 6.2 | Incident Management Teams (IMTs) | Minor | Updated to reflect 2018 status | Aimee Felker |
| 3.1 | Risk Overview | 3.1 | Risk Overview | Minor | Updated to reflect 2018 status | Ashley Matsu |
| 3.2.1 | General Planning Assumptions | 3.2.1 | General Planning Assumptions | Minor | Updated to reflect 2018 status | Eric Boettcher |
| 3.3.1 | Weather Related Emergencies | 3.3.1 | Weather Related Emergencies | Minor | Updated to reflect 2018 status | Mike Voss |
| 3.3.2 | Earthquakes and Tsunamis | 3.3.2 | Earthquakes | Updated | Added tsunami information | Eric Boettcher, Megan Stanton |
| 3.5 | Annex Development | 3.5 | Annex Development | Updated | Annex process and Con Ops sections enhanced | Julei Kim |
| 3.6 | Training and Exercises | 16 | Training and Exercises | Updated | Includes EPRS training courses | Aimee Felker |
| 3.6.2 | Exercises | 16.2 | Exercises | Minor | NGO, VO and CBO clarifications | Eric Boettcher |
| 3.6.3 | After Action Reports and Improvement Plans (AARs and IPs) | 16.3 | After Action Reports and Improvement Plans (AARs and IPs) | Updated | Updated to reflect 2018 status | Aimee Felker, Chris Snyder |
| 4.5 | Dual Commodity Response | 4.5 | Dual Commodity Response | Updated | DCPP and HBPP Emergency Plan information added | Tracey Vardas |
| 4.5.4 | Single Command with a Deputy Incident Commander for a Dual Commodity Incident | 4.5.4 | Single Command with a Deputy Incident Commander for a Dual Commodity Incident | Updated | HR Officer added to organizational chart | Aimee Felker |
| 5 | Organizational Charts | n/a | n/a | Proposed | Updated organizational charts proposed to reflect changes suggested by SMEs; pending approval of Director EP&R and VP Electric Transmission | |
| 5 | EOC Staffing (all positions) | 6 | EOC Command Staff | Updated | Updated to include documentation requirements | Aimee Felker |
| 5.1.8 | Liaison Officer (LNO) | 6.11 | Liaison Officer (LNO) | Updated | Updated to include Nuclear Liaison position | Tracey Vardas |

| 2018 Section | 2018 Table of Contents | 2017 Section | 2017 Table of Contents | Clarification | Change Detail | Recommended By |
|---|---|---|---|---|---|---|
| 5.1.9 | Human Resources Officer (HRO) | 6.12 | Human Resources Officer (HRO) | Updated | Duties updated | Eric Boettcher |
| ▲5.1.13 | EOC Support | 6.14.2 | Historian | New | EOC Support position added; incorporating existing duties not previously described in the CERP as well as the Historian and Business Continuity Specialist roles | Aimee Felker, Chris Snyder |
| 5.2 | Operations Section | 7.1 | Operations Section | Updated | Updated to include documentation requirements; Nuclear Liaison position renamed to Nuclear Technical Specialist | Tracy Vardas, Norma Ortiz |
| 5.2.4 | Generation Branch | 7.1.4 | Generation Branch | Updated | Names updated to reflect 2018 organizational structure, e.g., Hydro/Fossil changed to Power Generation, Nuclear Liaison changed to Nuclear Technical Specialist | Meg Richardson, Tracey Vardas |
| 5.2.5 | Nuclear | 7.1.5 | Diablo Canyon Power Plant (DCPP) Emergency Response Organization (ERO) | Updated | Updated to reflect 2018 status | Tracey Vardas |
| 5.4.4.1 | Technical Specialists | 7.3.4.1 | Technical Specialists | Updated | Moved Business Continuity role to EOC Support | Aimee Felker |
| 5.5 | Logistics Section | 7.4 | Logistics Section | Updated | Organizational Chart updated | Chuck Williams, Jr |
| ▲5.5.1 | Logistics Reporting Lead | | | New | | Chuck Williams, Jr |
| 5.5.2 | Service Branch | 7.4.1 | Service Branch | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| 5.5.2.1 | Physical Security Unit | | | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| 5.5.2.2 | Food / Admin Support Unit | | | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| 5.5.2.3 | Environmental Response Unit | | | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| 5.5.3 | Support Branch | 7.4.2 | Support Branch | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| 5.5.3.1 | Facilities Unit | | Facilities Unit | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| 5.5.3.2 | Base Camp / Staging Area Support | | Base Camp / Staging Area Unit | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |

| 2018 Section | 2018 Table of Contents | 2017 Section | 2017 Table of Contents | Clarification | Change Detail | Recommended By |
|---|---|---|---|---|---|---|
| 5.5.3.4 | Ground Support Unit | | | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| 5.5.3.5 | Supply Unit | | Supply Unit | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| ▲5.5.3.6 | Materials Buyers and Service Buyers | | | New | | Chuck Williams, Jr |
| 6.1.2 | Substation Emergency Center (SubEC) and T-Line Emergency Center (TLEC) | 8.1.2 | Substation Transmission Operations Emergency Center (STOEC) | Updated | Name changes | Laurie Jones |
| 6.1.3 | Electric Transmission Emergency Center (ETEC) | 8.1.3 | Electric Transmission Emergency Center (ETEC) | Updated | Name changes | Laurie Jones |
| 6.1.5 | Electric Region Emergency Center (REC) | 8.1.5 | Regional Emergency Center (REC) | Updated | Name change - added "Electric" to distinguish from Gas Emergency Center | Heather Martinez, Aimee Felker |
| 6.2.1 | Electric Distribution Control Center (DCCC) | 8.2.1 | Electric Distribution Control Center (DCCC) | Updated | Updated to reflect 2018 status | Aimee Felker |
| 6.2.2 | Electric Transmission / Vacaville Grid Control Center (VGCC) | 8.2.2 | Electric Transmission / Vacaville Grid Control Center (VGCC) | Updated | Name change: San Francisco Transmission Operations Center (TOC) to Rocklin Grid Control Center (RGCC) | Laurie Jones |
| 6.2.4 | Enterprise Network Operations Center (ENOC) | 8.2.4 | Enterprise Network Operations Center (ENOC) | Updated | Updated to reflect 2018 status | Norma Ortiz |
| 6.2.5 | Fairfield Security Control Center | 8.2.5 | Fairfield Security Control Center | Updated | Updated to reflect 2018 status | Norma Ortiz |
| ▲6.2.6 | Security Intelligence Operations Center (SIOC) | n/a | n/a | New | | Norma Ortiz |
| 6.2.7 | Rancho Cordova Information Operations Center (RCIOC) | 8.2.6 | Rancho Cordova Information Operations Center (RCIOC) | Updated | Updated to reflect 2018 status | Norma Ortiz, Aimee Felker |

| 2018 Section | 2018 Table of Contents | 2017 Section | 2017 Table of Contents | Clarification | Change Detail | Recommended By |
|---|---|---|---|---|---|---|
| ▲6.2.8 | Wildfire Safety Operations Center | n/a | n/a | New | WSOC added to reflect current PG&E emergency preparedness efforts | Aimee Felker |
| 6.3 | Support and Coordination Centers | 8.3 | Support and Coordination Centers | Updated | Updated to reflect 2018 status | Tamyra Walz, Chuck Williams Norma Ortiz |
| 6.4 | Emergency Field Facilities | 8.4 | Emergency Field Facilities | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| 6.4.1 | Base Camps | 8.4.1 | Base Camps | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| 6.4.2 | Staging Sites | 8.4.2 | Staging Sites | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| 6.4.3 | Micro-Sites | 8.4.3 | Micro-Sites | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| ▲6.4.4 | Materials Laydown Area | n/a | n/a | New | | Chuck Williams, Jr |
| 6.4.6 | Mobile Command Vehicle (MCV) and Emergency Communications Trailers | 8.4.5 | Mobile Command Vehicle | Updated | Updated to reflect 2018 status | Irene Lee |
| 7.4 | California State Government | 9.4 | California State Government | Minor | Alhambra Control Room in Southern California changed to Lincoln, CA BackUp | Laurie Jones |
| ▲7.4 | California State Government | 9.4 | California State Government | New | Added CPUC Decision 18-08-004 requiring Emergency Consumer Protections for customers during states of emergency | Emily Behr |
| 7.5 | United States Federal Government | 9.5 | United States Federal Government | Updated | North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) added | Laurie Jones |
| 8.1 | Emergency Plan Activation | 10.1 | Emergency Plan Activation | Minor | Changed "Emergency Levels" and "Incident Levels" to "Levels of Emergency" for consistency; note: 1 "Incident Levels" remains as it is part of a title of a referenced document | Heather Martinez |
| 8.6 | Triggers and Authorities to Activate Emergency Centers | 10.6 | Triggers and Authorities to Activate Emergency Centers | Updated | Updated to reflect 2018 status; name change of STOEC to SubEC/TLEC | Laurie Jones |
| 8.7 | Emergency Response Sequence | 10.7 | Emergency Response Sequence | Updated | Additional training references provided | Aimee Felker |

| 2018 Section | 2018 Table of Contents | 2017 Section | 2017 Table of Contents | Clarification | Change Detail | Recommended By |
|---|---|---|---|---|---|---|
| 8.8.2 | On-Call Teams | 10.8.2 | On-Call Teams | Updated | Updated to reflect 2018 status | Aimee Felker |
| 8.10 | Establish Command | 10.10 | Establish Command | Updated | Updated to reflect 2018 status; name change of STOEC to SubEC/TLEC | Aimee Felker |
| 8.11 | Notification | 10.11 | Notification | Updated | Updated to reflect 2018 status; name change of STOEC to SubEC/TLEC | Aimee Felker |
| 8.11.1 | Internal Call-Out Procedures | 10.11.1 | Internal Call-Out Procedures | Updated | Updated to reflect 2018 status | Aimee Felker, Tracey Vardas |
| 8.13 | Damage Assessment | 10.13 | Damage Assessment | Minor | Removed hyperlink to Gas Pipeline Earthquake Plan and Response Procedure – Risk Management Instruction (RMI-04); Consult GERP for additional information | Aimee Felker |
| 9 | Resource Management, Mutual Assistance and Demobilization | 11 | Resource Management | Consolidated | Includes: Resource Management, Mutual Assistance and Demobilization. In 2017 these were three separate chapters. | Aimee Felker |
| 9.1.1 | Resource Check-In and Check-Out Process | 11.1 | Check-In and Check-Out Process | Updated | Updated to reflect 2018 status | Aimee Felker |
| 9.1.4 | Moving Resources | 11.4 | Moving Resources | Updated | Updated to reflect 2018 status (name update) | Laurie Jones |
| 9.1.6 | Vehicle, Equipment and Rental Management | 11.6 | Vehicle, Equipment and Rental Management | Updated | Updated to reflect 2018 status | Chuck Williams, Jr |
| 9.2 | Mutual Assistance | 12 | Mutual Assistance | Updated | Updated to reflect 2018 status | Julei Kim |
| 9.2.1 | Mutual Assistance Agreements | 12.1 | Mutual Assistance Agreements | Updated | Updated to reflect 2018 status | Julei Kim |
| 9.2.2 | Mutual Assistance Strategy | 12.2 | Mutual Assistance Strategy | Updated | Updated to reflect 2018 status | Julei Kim |
| 9.2.3 | Mutual Assistance Process | 12.3 | Mutual Assistance Process | Updated | Updated to reflect 2018 status | Julei Kim |
| 9.2.4 | Documenting Mutual Assistance Work | 12.4 | Documenting Mutual Assistance Work | Updated | Updated to reflect 2018 status | Julei Kim |

| 2018 Section | 2018 Table of Contents | 2017 Section | 2017 Table of Contents | Clarification | Change Detail | Recommended By |
|---|---|---|---|---|---|---|
| 9.2.5 | EEI Resource Allocation Management Program (RAMP-UP) | 12.5 | EEI Resource Allocation Management Program (RAMP-UP) | Updated | Updated to reflect 2018 status | Julei Kim |
| 9.2.6 | National Response Event (NRE) | 12.6 | National Response Event (NRE) | Updated | Updated to reflect 2018 status | Julei Kim |
| ▲9.2.7 | NRE Roles and Responsibilities | n/a | n/a | New | | Julei Kim |
| ▲9.2.8 | PG&E's Role in the NRE | n/a | n/a | New | | Julei Kim |
| 9.3.1 | Demobilization Roles and Responsibilities | 13.1 | Demobilization Roles and Responsibilities | Updated | Updated to reflect 2018 status | Aimee Felker, Saman Saffarzadeh |
| 9.3.5.4 | EOC After Action Reports (AARs) | 13.5.4 | EOC After Action Reports (AARs) | Updated | Updated to reflect 2018 status | Aimee Felker, Chris Snyder |
| 10 | Coordination and Communication | 14 | Coordination and Communication | Updated | Updated to reflect 2018 status | Aimee Felker, Tamyra Walz |
| 10.1.5 | Dual Commodity Coordination and Communication | 14.1.5 | Dual Commodity Coordination and Communication | Updated | Updated to reflect 2018 status | Teresa Young Tessa Burns |
| 10.1.5.1 | Gas and Electric Coordination Process | 14.1.5.1 | Gas and Electric Coordination Process | Minor | Link updated | Aimee Felker, Tessa Burns |
| App A | Maps and System Details | App A | Maps and System Details | Minor | Updated to reflect 2018 status | Aimee Felker |
| App B | Activation Criteria and Organizational Charts | App B | Levels of Emergency and Activation Criteria for PG&E EOC Organizational Chart | Minor | Updated to reflect 2018 status | Aimee Felker |
| App D | Schedules, Agendas and Reports | App E | Meeting and Report Schedules with Sample Agendas | Updated | Updated Schedules, Agenda, Reports and descriptions | Aimee Felker |
| App E | Mobile Command Vehicles (MCV) | App F | Mobile Command Vehicles (MCV) | Minor | Updated to reflect 2018 status. | Irene Lee |
| App G | Acronyms and Glossary | App H | Acronyms and Glossary | Minor | Several terms added, e.g., WSOC | Aimee Felker |

| 2018 Section | 2018 Table of Contents | 2017 Section | 2017 Table of Contents | Clarification | Change Detail | Recommended By |
|---|---|---|---|---|---|---|
| MOVED | moved to section 2.5 | 5 | PG&E Emergency Preparedness Departments | n/a | n/a | Aimee Felker |
| MOVED | moved to section 2.5 | 5.1 | Company Emergency Management Practice | n/a | n/a | Aimee Felker |
| MOVED | moved to section 2.5 | 5.2 | Emergency Organization and Responsibilities | n/a | n/a | Aimee Felker |
| MOVED | moved to section 2.5 | 5.3 | Gas Emergency Planning Team | n/a | n/a | Aimee Felker |
| MOVED | moved to section 2.5 | 5.4 | Diablo Canyon Power Plant (DCPP) Emergency Preparedness | n/a | n/a | Aimee Felker |
| MOVED | moved to section 2.5 | 5.5 | Power Generation Emergency Preparedness | n/a | n/a | Aimee Felker |
| MOVED | moved to section 2.6 | 6 | PG&E Emergency Management Organization (EMO) | n/a | n/a | Aimee Felker |
| MOVED | moved to section 2.6 | 6.1 | Corporate Incident Management Council (CIMC) | n/a | n/a | Aimee Felker |
| MOVED | moved to section 2.6 | 6.2 | Incident Management Teams (IMTs) | n/a | n/a | Aimee Felker |
| MOVED | moved to section 4 | 15 | Emergency Financial Guidance | n/a | n/a | Aimee Felker |
| MOVED | moved to section 4 | 16 | Training and Exercises | n/a | n/a | Aimee Felker |
| MOVED | moved to section 4 | 16.1 | Training | n/a | n/a | Aimee Felker |
| MOVED | moved to section 4 | 16.2 | Exercises | n/a | n/a | Aimee Felker |
| MOVED | moved to section 4 | 16.3 | After Action Reports and Improvement Plans (AARs and IPs) | n/a | n/a | Aimee Felker |

| 2018 Section | 2018 Table of Contents | 2017 Section | 2017 Table of Contents | Clarification | Change Detail | Recommended By |
|---|---|---|---|---|---|---|
| MOVED | moved to Appendix B | App C | Emergency Operations Center (EOC) Organizational Chart | n/a | n/a | Aimee Felker |

# Minor Revision Guidance Document Analysis (GDA)
# Gas System Operations Control Room Management
# TD-4436S, Rev: 8a

| 1. Document Coordinator: | Dominique Erdozaincy | 2. Date of Request: | 08/24/2018 |
|---|---|---|---|

**3. Change Details**

| Section/Step | What to Change/Add/Delete |
|---|---|
| 2 (Note) | Senior Gas System Coordinators and Gas System Coordinators are the ultimate decision makers during normal, abnormal and emergency operating conditions because their roles and Operator Qualifications require comprehensive system knowledge, situational awareness, gas system operations expertise and engagement with related systems and tools on a regular basis. *While information and influence can be provided to the Senior Gas System Coordinator and Gas System Coordinators, no one can supersede their authority* |
| Attachment 2 | Replaced GTCC and GDCC with GCC |
| | |
| | |

**4. Reason for the Change**

**Main drivers and considerations:** New regulatory requirement – 49CFR192.631

**Additional info for leadership awareness:** Leadership will be profiled for GAS-9225ILT. Target deadline for completion is Dec 15, 2018.

**5. Implementation Plan**

Tailboard to Gas Control Personnel – Alfred Musgrove

Provide required training (GAS-9180WBT and GAS-9225ILT) – Alfred Musgrove

Awareness email to Leadership and Gas Control personnel regarding the drivers for the required training prior to implementation – Alfred Musgrove

**6. Stakeholder Reviewers**

| Name | Department/Role | Review Date |
|---|---|---|
| Cheryl Quijano | Document Steward, CRM Process & Training | 08/24/2018 |
| Dominique Erdozaincy | Document Coordinator, Standards Engineering | 08/24/2018 |
| Alfred Musgrove | Manager, CRM Processes & Training | 09/11/2018 |
| Frank Mahoney | Senior Technical Authority, Gas Control Strategy & Support | 09/10/2018 |
| Dan Menegus | Document Approver, Gas System Operations | TBD |
| Jerrod Meier | Principal Engineer, Standards Engineering | 09/07/2018 |
| Frank Maxwell | Process Owner, Sr Mgr, Gas Distrib and Transm Control | 09/12/2018 |
| Stephen Sass | Process Safety | 09/14/2018 |
| | | |
| | | |
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| | | |
| | | |
| | | |

# Minor Revision Guidance Document Analysis (GDA)
# Gas System Operations Control Room Management
# TD-4436S, Rev: 8a

| **Schedule & Priority** |
|---|
| **7. Priority:** ☒ **Regular** *(monthly publication)* ☐ **High** *(Publish within 24 hours of EDRS approval)* |

| Reason (for *High* priority only): |
|---|

| **8. New Effective Date:** |
|---|
| **9. EDRS Sequential** ☐ **or Concurrent** ☒ |

| **Approvers:** Dominique Erdozaincy, Cheryl Quijano, Dan Menegus, Tuesdai Powers |
|---|
| **Reviewers** (if any): NA |
| **Cc** (if any beyond the default): NA |

| **10. Minor Revision Request Reviewed By** | |
|---|---|
| **Supervisor:** Matt Davidson | **Date:** 08/24/2018 |
| **11. Proposed Schedule:** | |
| **Milestone** | **Date** (or NA if not applicable) |
| Submitted for tech writing | **09/13/2018** |
| Pre-EDRS Review | 09/19/2018 |
| Uploaded to EDRS | 09/26/2018 |
| Approved in EDRS | 10/10/2018 |
| *(Publication date is determined by Priority, entered in #7; effective date is entered in #8)* | |

| **12. Document Category** | | | |
|---|---|---|---|
| ☐ **Engineering** | ☐ **Construction** | ☒ **Maintenance & Operations** | ☐ **Emergency/Admin** |

**PACIFIC GAS AND ELECTRIC COMPANY**

**ATTACHMENT 5**

**Patrolling Gas Pipelines; Utility Procedure TD-4412P-07, Rev. 07**

**PUBLIC VERSION**

# Patrolling Gas Pipelines

## SUMMARY

This utility procedure establishes a process for patrolling Pacific Gas and Electric Company (PG&E or Company) gas facilities (facilities).

Level of Use: Informational Use

## TARGET AUDIENCE

Aerial patrollers and supervisors, ground patrol personnel and supervisors (including all personnel who are operator-qualified to perform patrolling), ground safety check personnel and supervisors.

Other personnel involved in patrol-related functions, including, but not limited to, PG&E Academy, gas control, operator qualifications (OQ), mapping, and asset management personnel.

For information only: transmission integrity management and distribution integrity management personnel.

## SAFETY

Hazards impacting this work include, but are not limited to the following conditions:

- Human presence or activity
- Environmental surroundings, including weather conditions and wires
- Excavation activities
- Machinery and equipment
- Tripping and slipping hazards
- Steep and unstable terrain
- Animals and vegetation
- Traffic conditions

Consider the following safety practices while working in areas when traffic is a safety concern:

- Face traffic whenever possible to maintain situational awareness.
- Use tools and equipment as appropriate to reduce exposure to traffic (e.g., mobile system to survey main in roadways).
- Use of traffic control or additional personnel to ensure visibility and personal safety.

  

# Patrolling Gas Pipelines

## BEFORE YOU START

Become familiar with additional details about executing patrol-related duties as provided in the current *Pipeline Patrol Program Guide* (Program Guide).

This procedure contains covered tasks requiring qualifications. Please consult the PG&E gas qualifications task list or contact the Gas Qualifications department for covered task information, including date available and effective dates.

### Personal Protective Equipment (PPE)

Wear the following personal protective equipment (PPE), at a minimum, plus any other applicable PPE as specified in the Gas Operations PPE Matrix and the Code of Safe Practices:

**Required to wear:**

- Traffic vest (ground patrol only)
- Proper work footwear (no sneakers allowed)
- Long-sleeved shirt (ground patrol only)
- Long pants (ground patrol only)
- Safety glasses

**Must be available:**

- Hard hat (ground patrol only)
- Work gloves
- Hearing protection

**Recommended:**

- Sufficient hydration
- Sufficient protection from the elements
- Co-worker communication plan and means of communication

Pacific Gas and Electric Company®

Utility Procedure: TD-4412P-07
Publication Date: 04/18/2018 Effective Date: 06/01/2018 Rev: 7

# Patrolling Gas Pipelines

## TABLE OF CONTENTS



## PROCEDURE STEPS

### 1 Scope of Patrol

All personnel performing tasks outlined in this utility procedure must perform the duties outlined herein in compliance with the federal regulations and Company standards that this procedure is designed to reflect.

Any identified task that requires deviation from any part of this procedure must follow the process outlined in Utility Procedure TD-4001P-07, “Gas Guidance Document Variance Process,” and must be approved before commencing the identified task. Any other deviation, whether accidental or intentional, necessary or voluntary, must be reported to the appropriate supervisor as soon as practical upon discovery.

1.1 Transmission Facilities

1. Transmission pipeline and gathering lines to be patrolled are determined by Asset Knowledge Management.

2. Patrol group determines the frequency of patrols based on the size of the line, operating pressures, class location, terrain, weather, and other relevant factors. See Section 2.

1.2 Distribution Mains

1. Distribution mains may be requested to be patrolled that have been identified in places, or on structures, where anticipated physical movement or external loading could cause leakage or failure. See Attachment 2, “Distribution Patrolling Process Decision Flowchart,” for process steps. These are reported to gas control when found by field personnel.

2. Frequency of patrolling mains is determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety. See Section 2.

- Gas control notifies aerial and ground patrol (Patrol), or (if necessary) requests Gas Operations personnel to create a Corrective Action Program (CAP) item and assign to Patrol.
- Per Attachment 2, Patrol evaluates the request and, if necessary, adds location to inventory and executes patrol.
- Patrol documents and maintains the system of record.

1.3 Any other gas facilities requiring special attention, as conditions warrant. See Section 2.3.

## 2 Frequency of Patrol

2.1 Perform patrols at the required frequencies. Refer to Table 1 for minimum frequency requirements.

**Table 1. Minimum Patrol Frequency Requirements**

| Facilities | Minimum Frequency | Acceptable Methods |
|---|---|---|
| Transmission and gathering pipelines | Quarterly[1] | Aerial and/or Ground |
| Distribution pipelines – mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage and consequent hazards to public safety: | | |
| • In business districts | Quarterly[1] | Aerial and/or Ground |
| • Outside business districts | Semiannually[2] | Aerial and/or Ground |

1. At least four times each calendar year, not to exceed 4½ months to the date.
2. At least twice each calendar year, not to exceed 7½ months to the date.

2.2 Methods of Patrol

1. Conduct patrol either aerially (via fixed-wing airplane or helicopter), or on the ground (via car, truck, 4×4 off-road vehicle, walking, or other appropriate means of traversing the right-of-way, excluding motorcycles).

2. Patrol may be conducted remotely using telephoto lenses, still images, video images, or other data from multispectral sources by dedicated qualified personnel not acting as pilot in command.

2.3 Special Patrols

1. Patrol Supervisor reviews requests for additional patrols.

2. Patrol Supervisor may order additional patrols as conditions warrant for the purpose of monitoring specific areas and/or specific observations.

3. Special patrols are subject to the requirements governing the corresponding patrol type (ground or aerial) outlined in this utility procedure.

2.4 Reportable Observations

1. Refer to the following for reportable observations and applicable zones of review:

- Attachment 1, “Reportable Observations”
- Job Aid TD-4412P-07-JA01, “Identification of Common Geohazards”
- Job Aid TD-4412P-07-JA02, “Identification of Unsafe Excavations”
- Job Aid TD-4412P-07-JA03, “Identification of Pipeline Corrosion”

**3 Records**

3.1 Electronic data collection methods are preferred over paper forms.

1. IF approved electronic data collection methods are unavailable,

   THEN the forms listed in this document must be completed on paper to record patrol activities and observations.

3.2 IF using electronic data collection technology to record a patrol activity,

THEN various types of electronic data, such as collected GPS tracks, captured geospatial observation points, recorded images, or multispectral data, constitute a record.

3.3 IF a paper form is used to record a patrol activity,

THEN the original, completed form (or digital scans thereof), as well as any included supplemental materials (e.g., photos, etc.), constitute a record.

3.4 As it may not be practical to complete Form TD-4412P-07-F01, “Ground Patrol Report,” for each of the many facilities, a single patrol report or entry may represent patrol of a group of facilities. In these cases, provide accessory documentation to identify all facilities patrolled.

3.5 For all patroller duties described below, it is strongly encouraged that digital images of each observation are captured whenever possible and included as supplements along with the record of the activity.

3.6 Retain records per the Record Retention Schedule.

## 4 Aerial Patroller Duties

4.1 Performing Aerial Patrol

1. The purpose of aerial patrol is to observe surface conditions on and adjacent to the pipeline right-of-way (according to the current system of record for geospatial location of the pipeline) and to record reportable observations.

| NOTE |
| --- |
| Aerial patrollers are crewmembers. |

2. Receive patrol assignment from Patrol Supervisor, based on patrol frequency and location. Flight schedules are subject to change due to any of the following:
   - Safety concerns
   - Crew availability
   - Equipment availability
   - Inclement weather
3. Follow pre-flight safety and flight tracking requirements outlined in the program guide, including providing a mission brief, reviewing maintenance and inspection periods, and complying with aircraft tracking requirements.
4. While in flight, maintain situational awareness and communicate hazards to pilot and patrol team, as appropriate. Safety is the top priority.
5. Navigate flight route and direct the pilot regarding the mission plan.

4.1 (continued)

6. Observe surface conditions for reportable observations within Immediate and Adjacent Zones of the assigned facilities (See Section 2.4, “Reportable Observations.”).

   a. List all new observations even if it is believed that ground patrol has already investigated the observation.

   b. IF an observation poses an urgent threat to pipeline safety or integrity,

      THEN prioritize reporting the observation in accordance with the program guide.

7. Record observations on Form TD-4412P-07-F04, “Aerial Patrol Report.”

4.2 Performing Video Review

1. Video of aerial patrol flights is recorded whenever practical. The purpose of reviewing this video is:

   a. To observe Immediate and Adjacent Zones, per Section 2.4, as a quality control measure for aerial patrol.

   b. To survey the area 0 feet to 660 feet (or farther, depending on potential impact radius of the pipeline) from both sides of the pipeline for observations that may result in a change in human occupancy. (Refer to Form TD-4412P-07-F05, “Report of Change in Human Occupancy,” for details.)

      (1) IF a different method of reviewing the pipeline for changes in human occupancy (e.g., aerial photography, change detection, ground survey, etc.) is used, as approved by the Patrol Supervisor,

      THEN human occupancy reviews are not required during video review and are performed only as directed by the Patrol Supervisor.

2. Review video of aerial patrol flights as per Program Guide.

   a. Personnel reviewing the video must fulfill the video review training requirements outlined in the Program Guide.

   b. Whenever possible, review of flight video must be performed by someone other than the lead aerial patroller who performed the corresponding patrol.

## 5 Performing Ground Patroller Duties

5.1 Ground Patrol

1. Conduct ground patrol as a scheduled activity as directed by the Patrol Supervisor, to observe surface conditions on and adjacent to pipeline right-of-way, according to the current system of record for geospatial location of the pipeline and record reportable observations.

   a. Receive assigned facilities to patrol from ground Patrol Supervisor.

   b. Observe surface conditions for reportable observations within Immediate and Adjacent Zones of the assigned facilities (refer to Section 2.4).

5.2 Ground Investigation

1. Conduct ground investigation in response to an aerial or video review observation, as determined by the ground Patrol Supervisor (see Section 6.1.2).

   a. Unlike a ground patrol, a ground investigation is a targeted activity of a specific area at a given location.

   b. Receive assigned aerial or video review observations to investigate from ground Patrol Supervisor.

   c. Locate the observation using the provided GPS coordinates or other geographic information.

      (1) Observe the following areas for reportable observations.

      - Location of the reported aerial patrol or video review observation.
      - Area between and including the observation and nearest patrolled facility.

2. Performing Special Ground Patrol

   a. Perform special ground patrol in addition to scheduled patrol activities as a targeted observation of a specific area and/or specific observation types.

      - Unlike a scheduled ground patrol, a special ground patrol might not include observation of the entire Immediate and Adjacent Zones at a given location.

5.3 Emergency Situations

1. IF, during the course of patrol activities, the ground patroller determines that immediate action is necessary to maintain the safe operation of PG&E facilities,

   THEN perform the following steps:

   a. Retreat to a safe location, if necessary.

   b. Contact 9-1-1 if there is an immediate threat to public safety.

   c. Contact the ground Patrol Supervisor or, if unavailable, PG&E Gas Control at [redacted]

| NOTE |
| --- |
| Personnel must hold current OQs for all applicable tasks performed. |

   d. Perform duties and record actions as directed by the ground Patrol Supervisor or gas control, based on capacity to respond safely.

   e. Resume previous task, unless otherwise directed by ground Patrol Supervisor.

5.4 Recording Patrol-Related Activities

1. Record patrol-activity performed, observations, and any corrective or follow-up actions performed, on Form TD-4412P-07-F01, and any supplemental documents based on these findings, as necessary.

   a. IF a facility cannot be properly identified, located, accessed, or otherwise patrolled safely and accurately, due to conditions including but not limited to prohibitive vegetation, locked gates, hazardous conditions, missing markers, prohibitive facility maintenance,

      THEN record the issue on Form TD-4412P-07-F01.

   b. Complete Form TD-4412P-07-F05, “Report of Change in Human Occupancy,” if applicable per Attachment 1, due to observations or follow-up actions (e.g., warnings to third-parties encroaching upon the pipeline, notices of unsafe work practices).

2. Submit completed records and supplemental materials to the ground Patrol Supervisor for review and approval as soon as practical.

5.5 Performing Human Occupancy-Related Activities

1. Human Occupancy Review

- The purpose of a human occupancy review is to evaluate the area from 0 feet to 660 feet (or farther, depending on the potential impact radius of pipeline) from both sides of the pipeline for observations that may result in a change in human occupancy.

- Unless a pipeline is reviewed by another method (e.g., video review, aerial photography, change detection, etc.), a human occupancy review must be performed quarterly (at least 4 times each calendar year, not to exceed 4½ months to the date) or as determined by the Class Location team or other responsible parties.

2. Ground Patroller Duties for Human Occupancy Reviews

a. Using a scale map of the area, ensure to observe 0 feet to 660 feet (or farther, if directed by Asset Knowledge Management or other responsible party) from both sides of pipeline for reportable observations. Whenever there is a reportable observation, perform the following:

(1) Record investigation on Form TD-4412P-07-F09, “Human Occupancy Review Report,” and complete any supplemental documents based on these findings as necessary.

(2) IF a facility cannot be properly identified, located, accessed, or otherwise reviewed safely and accurately, due, for example, to prohibitive vegetation, locked gates, hazardous conditions, missing markers, prohibitive facility maintenance, etc.,

THEN record the issue as indicated on Form TD-4412P-07-F09.

(3) Provide completed Form TD-4412P-07-F09 to asset knowledge management personnel.

b. Submit completed records and any supplemental materials to Patrol Supervisor for review and approval as soon as practical.

5.5 (continued)

3. Human Occupancy Investigation

A human occupancy investigation is a targeted investigation performed in response to a request from class location or high consequence area personnel for additional information concerning a relevant aerial or video review observation.

a. Ground Patroller Duties for Human Occupancy Investigations

(1) Receive assigned aerial patrol or video review observation to investigate from Patrol Supervisor.

(2) Locate the observation using the provided GPS coordinates and/or other geographic information.

(3) Observe location for changes in human occupancy. Refer to Form TD-4412P-07-F05.

b. Record investigation on Form TD-4412P-07-F05.

c. Submit completed records and any supplemental materials to Patrol Supervisor for review and approval as soon as practical.

4. Encountering Other Reportable Observations

a. IF, while performing a human occupancy review, ground patroller observes reportable observations not related to human occupancy per Attachment 1,

THEN follow the process for ground patrol as stated in Section 4.1. Record finding on Form TD-4412P-07-F01.

b. IF during the course of a human occupancy review, ground patroller determines that immediate action is necessary to maintain safe operation of a facility,

THEN refer to Section 5.1.

## 6 Local Ground Patrol Supervisor Duties

6.1 Local Ground Patrol Supervisor Duties in Response to Aerial Patrol and Video Review Observations

1. Receive selected aerial patrol and video review observations from Patrol.

2. Respond to each received aerial patrol or video review observation by ONE of the following methods:

   a. Dispatch qualified personnel to perform a ground investigation at the site of the observation as soon as practical (given the urgency of the observation). Refer to Section 4.1 for details.

   b. IF the observation has been previously ground investigated, AND supervisor determines that further investigation is not necessary,

      THEN note these facts, together with the date of the previous ground investigation in the provided field on the corresponding observation record.

   c. Explain, in writing, in the provided field on the corresponding observation record, why the observation does not require investigation. Use information such as USA ticket numbers, PG&E work order or clearance numbers, standby information, etc., when available.

6.2 Additional Local Ground Patrol Supervisor Duties

1. Maintain and equip a staff of operator-qualified ground patrollers.

2. Dispatch ground patrollers to patrol or investigate assigned facilities.

3. Conduct necessary actions to ensure the safety and integrity of facilities based on observations reported during patrol.

4. Ensure appropriate follow-up actions are completed and recorded for all ground patroller findings.

5. Review records submitted by the ground patrollers, and ensure that all necessary materials have been included and accurately completed. If paper forms were used, sign all forms upon approval.

6. Submit records to the Patrol Group.

7. IF paper forms were used,

   THEN submit scans or electronic equivalents of all patrol-related forms to the Patrol Supervisor at PatrolReportsSubmiss@pge.com, or elsewhere as directed by the Patrol Supervisor, as soon as practical.

6.2 (continued)

8. File any paper documents locally, unless otherwise directed by the Patrol Supervisor.

9. Recommend changes to the inventory of facilities to be patrolled, AND/OR patrol frequency to the Patrol Supervisor, as conditions warrant.

## 7 Ground Safety Check Personnel Duties

7.1 Perform ground safety checks as a timely follow-up activity to observations reported by aerial patrol, video review, or other sources, to ensure the safety and integrity of PG&E facilities.

**NOTE**

Ground patroller forms cannot be used for ground safety check.

7.2 Ground safety check personnel must record their activities and findings according to processes of their department.

7.3 IF notified of an observation requiring a response by ground safety check personnel,

THEN the ground safety personnel must provide the pipeline patrol program with a tracking number or other linkage to the record of the received notification and follow up activity.

7.4 IF it is determined that there is no threat to PG&E facilities,

THEN no further actions or documentation are required by this procedure.

7.5 Unless otherwise directed, emergency situations must be reported directly to PG&E Gas Control at [redacted], while non-emergency observations must be communicated to the appropriate department supervisor, a pipeline engineer, the Patrol Supervisor, or submitted to the Corrective Action Program per Utility Procedure TD-4020P-01, “Gas Operations Corrective Action Program (CAP) Implementation,” as soon as practical.

## 8 Patrol Supervisor Duties

8.1 Ensure compliance requirements of patrol are fulfilled.

8.2 Oversee the safe operation of patrols.

- The Patrol Supervisor has the authority to suspend an aerial or ground patroller, or all patrol operations, until such time as the supervisor deems the situation safe to resume.

8.3 Review, validate, and incorporate improvement or safety recommendations from aerial patrollers, pilots, field personnel, and other sources, into future patrols as appropriate.

8.4 Conduct quality control efforts and implement program improvements.

8.5 Conduct performance evaluations of aerial patrollers. Document evaluation on Form TD-4412P-07-F10, “Aerial Patroller Performance Evaluation.”

8.6 Asset Management Responsibilities

- Notify aerial patrol and local ground Patrol Supervisors of facilities to be patrolled by each group’s respective patrol method.
- Schedule aerial patrols and assign duties to aerial patrollers as crewmembers.
- Maintain a centralized database of patrol records.
- Notify ground and aerial patrollers or local ground Patrol Supervisors of any incomplete or missing records.
- Determine post-patrol follow-up actions.
- Forward observations, as necessary, to appropriate local ground patrol support personnel or other group for post-patrol follow-up action. Refer to Program Guide for details.

**END of Instructions**

**DEFINITIONS**

**Class location:** A “class location unit” is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1- mile (1.6 kilometers) length of pipeline.

**Crewmember:** A person assigned to perform duty in an aircraft during flight time (Code of Federal Regulations Title 14 CFR §1.1, “General Definitions”).

**Distribution line:** A pipeline other than a gathering or transmission line (Code of Federal Regulations Title 49 CFR §192.3, “Definitions”).

**Gathering line:** A pipeline that transports gas from a current production facility to a transmission line or main (Code of Federal Regulations Title 49 CFR §192.3, “Definitions”). This term includes collection lines taking gas from wells.

**High consequence area:** An area identified by Method 2 per Code of Federal Regulations Title 49 CFR §192.903, “What definitions apply to this subpart,” *High consequence area* (2).

**Main:** A distribution line that serves as a common source of supply for more than one service line (Code of Federal Regulations Title 49 CFR §192.3, “Definitions”).

Definitions (continued)

**Potential impact radius:** The radius of a circle within which the potential failure of a pipeline could have significant impact on people or property (Code of Federal Regulations Title 49 CFR §192.903, “What definitions apply to this subpart?”).

**Transmission line:** (based on Code of Federal Regulations Title 49 CFR §192.3, “Definitions”) A pipeline, other than a gathering line, that meets ANY of the following criteria:

1. Transports gas from another transmission line, gathering line, or storage facility to any of the following:
   a. Distribution center.
   b. Storage facility.
   c. Large-volume customer that is not downstream of a Distribution Center.
2. Operates at or above a hoop stress of 20 percent specified minimum yield strength (SMYS), or is upstream of a segment of pipe operating at or above a hoop stress of 20 percent SMYS.
3. Transports gas within a storage field.

## IMPLEMENTATION RESPONSIBILITIES

An email communication will be sent by Aerial and Ground Patrol Supervisor after publication to all the impacted groups. The Aerial and Ground Patrol group will receive a mandatory tailboard from supervisors.

The Patrol Supervisor will host meetings and/or conference calls with target audience to communicate the changes to this utility procedure.

## GOVERNING DOCUMENT

Utility Standard TD-4412S, “Preventing Damage to Underground Facilities”

## COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Federal Code Requirements - Code of Federal Regulations (CFR) Title 49:

49 CFR §192.705, "Transmission lines: Patrolling," with respect to establishing a patrol program to observe threats to the safety and operation of transmission facilities in accordance with additional criteria regarding the frequency, methodology, and scope of these patrols.

49 CFR §192.709, “Transmission Lines: Record Keeping,” with respect to record requirements, which have been exceeded by CPUC General Order 112-F, §145.1c, issued on 7/1/2015.

Compliance Requirement / Regulatory Commitment (continued)

49 CFR § 192.721, "Distribution systems: Patrolling," with respect to establishing a patrol program to observe threats to the safety and operation of distribution facilities in accordance with additional criteria regarding the frequency and scope of these patrols.

49 CFR §192.613, "Continuing Surveillance," with respect to providing continuing surveillance of changes in class location, failures, and other unusual operating and maintenance conditions of gas facilities.

49 CFR §192.707, "Line markers for mains and transmission lines," with respect to the installation and maintenance of pipeline markers.

49 CFR §192.903, "What definitions apply to this subpart?" (Subpart O--Gas Transmission Pipeline Integrity Management), with respect to identifying high consequence areas.

49 CFR §192.935, "What additional preventive and mitigative measures must an operator take?" with respect to monitoring high consequence areas.

**REFERENCE DOCUMENTS**

**Developmental References:**

Risk Management Procedure, RMP 08-Rev. 08

Utility Procedure TD-4127P-06, “Class Location and High Consequence Area Data Processing and Management”

Utility Standard TD-4127S, “Class Location Determination and Compliance Requirements"

Utility Standard TD-4490S, “Gas Pipeline Rights-of-Way Management”

Risk Management Procedure, RMI-04

Risk Management Procedure, RMI-04A-Rev. 01

Utility Standard SAFE-1001S, "Safety and Health Program Standard"

**Supplemental References**:

Utility Procedure TD-4001P-07, “Gas Guidance Document Variance Process”

Utility Procedure TD-4020P-01, “Gas Operations Corrective Action Program (CAP) Implementation”

Utility Standard TD-4810S, “Gas Transmission Integrity Management Program”

## APPENDICES

NA

## ATTACHMENTS

Attachment 1, “Reportable Observations”

Attachment 2, “Distribution Patrolling Process Decision Flowchart”

Form TD-4412P-07-F01, “Ground Patrol Report”

Form TD-4412P-07-F04, “Aerial Patrol Report”

Form TD-4412P-07-F05, "Report of Change in Human Occupancy"

Form TD-4412P-07-F09, “Human Occupancy Review Report”

Form TD-4412P-07-F10, “Aerial Patroller Performance Evaluation”

Job Aid TD-4412P-07-JA01, “Identification of Common Geohazards”

Job Aid TD-4412P-07-JA02, “Identification of Unsafe Excavations”

Job Aid TD-4412P-07-JA03, “Identification of Pipeline Corrosion”

## DOCUMENT RECISION

This document supersedes Utility Procedure TD-4412P-07, “Patrolling Pipelines and Mains,” Rev. 6, issued 11/25/2015.

## DOCUMENT APPROVER

Jason Shehan, Manager, Aerial and Ground Patrol

## DOCUMENT OWNER

Tuesdai Powers, Expert Gas Engineer, Gas Guidance Documents

## DOCUMENT CONTACT

Jennifer Brewer, Business Analyst, Aerial and Ground Patrol

# Patrolling Gas Pipelines

## REVISION NOTES

| Where? | What Changed? |
|---|---|
| Entire procedure | This procedure has been completely rewritten. High-level changes include:<br>• Added section on distribution patrolling to meet code requirements.<br>• Clarified or removed language to meet current work practice such as replacing Pipeline patrol process owner (PPPO) with Patrol Supervisor.<br>• Incorporated traffic safety information from Utility Bulletin TD-4001B-007.<br>• Replaced the former Attachment 2, “Special Patrol for Flooding,” with a new Attachment 2, “Distribution Patrolling Process Decision Flowchart.” |

**PACIFIC GAS AND ELECTRIC COMPANY**

**ATTACHMENT 6**

**Job Site Safety Analysis Form (JSSA) for Tailboard Briefing TD-4414P-F01, Rev. 0**

**PUBLIC VERSION**

Pacific Gas and Electric Company

# Job Site Safety Analysis (JSSA) for Tailboard Briefing

**If completing this form by hand, use non-erasable blue or black ink.**

TD-4414P-01-F01, Rev. 0
Publication Date: 11/15/2017
Effective Date: 03/01/2018

**If more writing space is needed, use a second JSSA form. Duplicate PM#, Date, and Job Location from Section One and attach together.**

## SECTION ONE

| PM#: | Name: | LAN ID: | Date: |
|---|---|---|---|

Job Location: Valid USA Ticket: YES ☐ NA ☐

What is the job (tasks) today? *Use Section Three if more space is needed.*

## SECTION TWO

Tools and instruments are calibrated? YES ☐ NA ☐ | Check qualifications for the job? YES ☐ NA ☐ | Check for proper PPE? YES ☐ NA ☐

All crews must identify job site hazards and evaluate controls before job starts.

**POTENTIAL SERIOUS INJURY & FATALITY (SIF) SUGGESTED TAILBOARD TOPICS** - ***Check all that apply.***

| | | | |
|---|---|---|---|
| 1. Animal Attack or Bite | ☐ | 12. Helicopter Use | ☐ |
| 2. Assault or Violent Attack | ☐ | 13. Live Electrical Work | ☐ |
| 3. Confined Space | ☐ | 14. Mobile Equipment Use (e.g., lifts, cranes, forklifts, etc.) | ☐ |
| 4. Contact with Motor Vehicle, Heavy Equipment, or Traffic Hazards | ☐ | 15. Motor Vehicle | ☐ |
| 5. Control of Hazardous Energy (LOTO, Clearance) | ☐ | 16. Off-road Vehicle Use | ☐ |
| 6. Dig-ins (USA) | ☐ | 17. Powered Tool Use | ☐ |
| 7. Dropped Object of Sufficient Mass to Cause Injury | ☐ | 18. Public Safety | ☐ |
| 8. Excavation (Excavation Safety Manual) | ☐ | 19. Suspended Loads and Rigging | ☐ |
| 9. Grounding (Live Electrical Work Supplement) | ☐ | 20. Watercraft Use | ☐ |
| 10. Hazardous Chemicals or Materials | ☐ | 21. Welding, Grinding, Cutting (Hot Work Permit) | ☐ |
| 11. Heat Exposures | ☐ | 22. Work at Heights (4 feet or greater) | ☐ |

| **SAFE WORK PRACTICES** - ***If no, stop the job and assess until resolved. Enter NA if not applicable to this job.*** | YES | NA |
|---|---|---|
| Did you identify and control ignition sources close to the job site (e.g., open flame, pilot flames, electrical equipment, non-explosion-proof tools and equipment, combustion engines), if there is a potential of gas release on site during work? | ☐ | ☐ |
| Did you identify and control potential gas migration routes into structures (e.g., house vents, crawl spaces, sewer and water lines), if there is a potential of gas release on site during work? | ☐ | ☐ |
| Did you identify, understand, and properly control any actions that could potentially result in a pipeline overpressure? | ☐ | ☐ |
| Did you identify ignition sources as a result of co-location of gas and electrical assets (e.g., overhead/below-ground lines)? If potential electric hazard exists, AND gas is released on site, notify the Gas Control Center. | ☐ | ☐ |
| For GPOM asset owned facilities, did you identify and apply Specific Site Safety Rules? | ☐ | ☐ |
| Does the job require welding, tapping, or cutting on steel distribution gas lines? If yes, perform tasks described in Utility Procedure TD-4640P-02, "Field Gas Carrier Pipe Checklist for Gas Operations" | ☐ | ☐ |
| Does the job require using a source of ignition when there are combustible or flammable materials within 35 feet of the work area? If yes, perform tasks described in Utility Procedure TD-4640P-01, "Hot Work Control - Fire Prevention." | ☐ | ☐ |

| LIST SIGNIFICANT SAFETY HAZARDS AND/OR ENVIRONMENTAL IMPACTS | LIST HOW TO CONTROL OR ELIMINATE THE HAZARDS AND/OR IMPACTS |
|---|---|
| | |
| | |
| | |
| | |

Pacific Gas and Electric Company

# Job Site Safety Analysis (JSSA) for Tailboard Briefing

If completing this form by hand, use non-erasable blue or black ink.

TD-4414P-01-F01, Rev. 0
Publication Date: 11/15/2017
Effective Date: 03/01/2018

**If more writing space is needed, use a second JSSA form. Duplicate PM#, Date, and Job Location from Section One and attach together.**

## SECTION THREE

- Do not make any changes to gas assets without proper review and approval.
- If conditions change, STOP THE JOB, seek advice, including discussion on new hazards and identification of controls, and update this section of the JSSA with time of change and additional hazards and controls. Document personnel included in the tailboard update with name and LAN ID.

**JOB SCOPE CHANGE / ADDITIONAL HAZARDS / OTHER NOTES**

## SECTION FOUR

- Assign roles and responsibilities in case of an accident, emergency or abnormal condition. In the event of serious injury or fatality call 911, and make area safe. As soon as it is safe to do so, call Gas Control Center with information about the emergency and call the supervisor.
- Verify that crew members know their own and other crew members' tasks and roles.
- All employees have the right, authority, obligation and responsibility to STOP THE JOB if an imminent hazard or serious perceived danger exists. Stop the job, notify the Person in Charge (PIC), investigate/evaluate, correct unsafe situations and resume when safe.

| Role | Crew Member / Visitor Signature | LAN ID | My PPE is in a condition to effectively protect against hazards |
|---|---|---|---|
| Person in Charge (PIC) | | | ☐ |
| | | | ☐ |
| | | | ☐ |
| | | | ☐ |
| | | | ☐ |
| | | | ☐ |
| | | | ☐ |
| | | | ☐ |
| | | | ☐ |
| | | | ☐ |

**ABNORMAL/EMERGENCY OPERATING CONDITIONS CALL**

| Transmission Gas Control | Distribution Gas Control |
|---|---|
| [redacted] | |

Tailboard Briefing information contained in the JSSA Form must be accessible to all personnel and visitors on site.

**PACIFIC GAS AND ELECTRIC COMPANY**

**ATTACHMENT 7**

# Change Log for 2019 Gas Safety Plan

# Attachment 7
## Change Log for 2019 Gas Safety Plan

This attachment lists changes in both the report narrative and the attachments between PG&E's 2019 Gas Safety Plan and 2018 Gas Safety Plan.

| Section | Change Log | Change Description |
|---|---|---|
| I.1 | Introduction | Clarified Structure of the Gas Safety Plan. |
| I. 2 | The Pursuit of Gas Safety Excellence | Defined PG&E's Gas Safety Excellence as its safety management system. |
| I.3.b | Workforce Safety | Added discussion regarding Serious Injury or Fatality (SIF) and Motor Vehicle Safety. |
| I.4 | Rewarding Safety Excellence | Added examples of safety awards. |
| -- | Natural Gas Leak Abatement | Not applicable for the 2019 Gas Safety Plan. The next update will be included in PG&E's 2020 Gas |
| II.1 | Employee Engagement | Enhanced discussion. |
| II.1.b | Compliance and Ethics Helpline | Added Federal Monitor Hotline. |
| IV.2 | Asset Family Structure | Updated image reflecting new Data Asset Family. |
| IV.2.h | Asset Family Structure | Added new Data Asset Family. |
| IV.5 | Mitigating the Risk of Loss of Containment | Minor revision of heading. |
| IV.5.a | Damage Prevention | Reorganized subsections and tables. Added Shut-In Gas performance. |
| IV.5.a. iii | Locate and Mark | Added discussion regarding Investigation (I).18-12-007 Order Instituting Investigation and Order to Show Cause on the Commission's Own Motion into the Operations and Practices of Pacific Gas and Electric Company with Respect to Locate and Mark Practices and Related Matters. |
| IV.5.i | Corrosion Control | Removed reference to units. |
| IV.5.n | Community Pipeline Safety Initiative | Removed graphic. |
| IV.6.b | Mitigating the Risk of Loss of Supply | Minor revision of heading. |
| IV.6.b | Operations Clearance Procedure | Removed historical discussion. |
| IV.7 | Mitigating the Risk of Inadequate Response and Recovery | Minor revision of heading. |
| IV.7.a | Gas System Operations and Control | Updated figure to differentiate visibility into transmission system backbone and transmission local transmission. |
| IV.7.c | Valve Automation | Simplified table. |
| V.3 | Workforce Training | Enhanced PG&E Academy discussion. |
| VI.2 | The Right Information to do the Work | Removed 2017 example. |
| VII.2 | Lean Capability Center | Condensed discussion of Super Gas Operations (SGO). Removed Lean Management heading. Enhanced Lean Management discussion. |
| VII.3 | Process Management | Updated graph for reader ease. Removed error correction metric. |

# Attachment 7
## Change Log for 2019 Gas Safety Plan

This attachment lists changes in both the report narrative and the attachments between PG&E's 2019 Gas Safety Plan and 2018 Gas Safety Plan.

| Section | Change Log | Change Description |
|---|---|---|
| Attachment 1 | PG&E Corporation Safety and Nuclear Oversight Committee, Resolution of the Board of Directors of PG&E Corporation, September 19, 2017 | Revised attachment. |
| Attachment 2 | 2018 Safety Committee Charter | Revised attachment. |
| Attachment 3 | Gas Safety Excellence; Gas Operations Policy: TD-01 Rev. 2 | New attachment. |
| Attachment 4 | Change Logs for Asset Management Plans, Emergency Response Plans, Gas Control Center Standard | Updated attachments. |
| Attachment 5 | Patrolling Gas Pipelines; Utility Procedure: TD-4412P-07 Rev. 7 | New attachment. |
| Attachment 6 | Job Site Safety Analysis (JSSA) for Tailboard Briefing TD-4414P-F01, Rev. 0 | New attachment. |
| Attachment 7 | Change Log for 2019 Gas Safety Plan | New attachment. |
| Attachment 8 | Contractor Safety Oversight Procedure – Gas Operations; Utility Procedure: SAFE-3001P-07 Rev. 3 | New attachment. |
| -- | 2017 Attachments that Have Not Changed | Excluded from 2019 Gas Safety Plan. |

**PACIFIC GAS AND ELECTRIC COMPANY**

**ATTACHMENT 8**

**Contractor Safety Oversight Procedure – Gas Operations Utility Procedure SAFE-3001P-07 Rev. 3**

**PUBLIC VERSION**

# Contractor Safety Oversight Procedure – Gas Operations

## SUMMARY

This utility procedure establishes Pacific Gas and Electric Company (PG&E or Company) gas operations processes for managing the safety of contractors performing work on PG&E natural gas facilities and other applicable standards and procedures referenced in this document. This procedure does not cover the following key elements of contractor oversight:

- Specification adherence
- Quality control
- Final documentation

Level of Use: Informational Use

## TARGET AUDIENCE

PG&E personnel who manage and oversee contracted and subcontracted work at PG&E Gas facilities, including work supervisors, inspectors, contract administrators, engineers, and other employees responsible for contractor oversight.

## SAFETY

Every PG&E employee is responsible for maintaining the safety of the public, of PG&E team members, and contractors. This utility procedure supports and is governed by SAFE-3001S, "Contractor Safety Standard." Adherence to this standard improves safety by ensuring the following:

a. Contractors and subcontractors are prequalified before performing work.

b. Contractor safety requirements have been included in the contract.

c. An executed contract is in place before starting work.

d. Safety hazards have been identified, planned for, and mitigated.

## BEFORE YOU START

Compare the publication date and version number of this utility procedure with the most recently published electronic version to verity that it is current.

Before completing the instructions and tasks in this procedure, PG&E personnel must read and understand SAFE-3001S and the other reference documents listed.

Read this entire procedure before implementing it.

  

# Contractor Safety Oversight Procedure – Gas Operations

## TABLE OF CONTENTS



## PROCEDURE STEPS

### 1 Overview

1.1 This Contractor Safety Oversight Program for gas operations is scalable according to project size and risk.

1.2 Each gas leader must assess the project risk before hiring the contractor and determine the suitable level of oversight.

1.3 Large projects are typically those which are greater than $1 million in contractor costs, more complicated than routine work, or high and medium risk projects.

1.4 Section 7 provides guidance on smaller high or medium risk projects ($1 million or less in contractor costs).

1.5 This procedure is applicable only to contractors performing high and medium risk field work as matrixed in SAFE-3001S.

1.6 Contractors and subcontractors performing low risk work are exempt from this procedure.

1.7 More communication regarding safety concerns is better than less communication.

1.8 See Table 1, “Risk and Oversight Matrix”.

**Table 1. Risk and Oversight Matrix – Publication Date 8/05/2016**

| Risk Category | Examples of Work Scopes or Work Activities | Primary Triggers |
|---|---|---|
| **Low Risk** | • Consulting, classroom training<br>• Office engineering, design, inspection (limited to no direct exposure to site hazards)<br>• Project Management Office (PMO) services<br>• Basic landscaping services such as lawn mowing, trimming, and pruning (no trenching or excavating)<br>• Manufacturing materials off PG&E premises<br>• Material delivery off PG&E premises (Shipping)<br>• Transportation of materials (limited to Material Handling off-site to PG&E premises)<br>• DOT Regulated Services<br>• Surveying, field inspection, construction management, engineering, design services that DO NOT include the primary trigger elements for higher risk work | • Performs **NO** work activities covered in the Medium/High risk definitions<br>• Does **NOT** require **ANY** of the pre-requisites covered in the Medium/High risk definitions<br>• Does **NOT** require Occupational Safety and Health Administration (OSHA) safety and health programs to address specific criteria identified below under high and medium risk definitions, including any OSHA required training, to mitigate task and location specific hazards |
| **Medium Risk** | • Excavating and trenching under 4 feet (includes hand digging)<br>• Geotechnical investigation, potholing, drilling, boring, horizontal directional drilling (HDD)<br>• Surveying, field inspection, construction management, engineering, design services that require specialized PPE<br>• Material Handling (on/off loading materials using mechanical electric or pneumatic equipment)<br>• Hazardous chemicals transport and handling<br>• Compressed natural gas (CNG) / liquefied natural gas (LNG) handling | • **Requires OSHA safety and health programs, including OSHA required training, to mitigate task and location specific hazards**<br>• **Work requires advanced or specialized PPE, beyond hard hat, safety boots, safety glasses and reflective vest** (Examples: personal fall arrest/restraint system, respirator, SCBA, rubber gloves, ear plugs/hearing protection, Flame Resistant (FR) clothing, Electrical Hazard (EH) boots, Energy Control Locks, Tyvek suit, etc.) |

**Table 1. Risk and Oversight Matrix - Continued**

| | | |
|---|---|---|
| **High Risk** | • Excavation and trenching beyond 4 feet (includes hand digging)<br>• Heavy equipment operation (crane, fork lift, front loader, backhoe, bobcat, buck truck, aerial lift, boom lift, skidder)<br>• Underwater diving operations<br>• Aviation operations (helicopter, fixed wing)<br>• Demolition / blasting / explosive work<br>• Utility tree trimming, clearance work, vegetation management<br>• Environmental remediation work, asbestos abatement, hazardous material disposal/treatment/transportation, contaminated soil<br>• General construction activities such as framing, sawing, cutting, welding, boring, blasting, coating, grinding, roofing, commercial painting, electrical/gas installation, scaffolding, civil<br>• Traffic control flagging<br>• Pesticide, herbicide application<br>• Armed security services<br>• Welding and/or hot tapping of gas lines<br>• Live-line / energized electrical work<br>• Conductor stringing / sagging removal<br>• Fault protection / grounding<br>• Radiological handling activities | • **Work requires specialized training, formal training, licensing, certification or qualification** (Examples: HVAC, Industrial Lift Truck, Permit Required Confined Space Training, Fall Protection Training, Crane Operator certification, pest control applicators license, FERC/NERC training, etc.)<br>• **Work <u>directly</u> exposes contract employee(s) to the hazards associated with the other work** (Examples: Suspended load spotters, aggregate haulers where delivery of materials requires operating equipment traffic control flaggers, technical services consultants that need to enter a permit require confined space or work at heights needing fall protection, etc.) |

## 2 Roles and Responsibilities

2.1 This section describes the roles and responsibilities for the Contractor Safety Oversight Program.

2.2 Table 2 describes PG&E site representatives.

**Table 2. Contractor Safety Oversight Program Responsibilities**

| Personnel | Description | Qualifications | Typical Job Titles | Responsibilities |
|---|---|---|---|---|
| Competent Site Representative | • Personnel filling this role may include, but are not limited, to construction manager, lead inspector, construction supervisor, or construction working foreman.<br>• Directors and managers may authorize others (delegates), such as project managers or engineers, to fill the role of a PG&E site representative<br>• Ensures that PG&E-specific safety considerations have been communicated to the contractor before implementing the contract work. | • Capable of identifying existing and predictable hazards in the surroundings or working conditions that are unsanitary or dangerous<br>• Has training, knowledge, or experience related to the work to be performed and knowledge of the appropriate mitigation measures for the associated hazards.<br>• May have formal training to identify and mitigate hazards associated with specific high-risk activities.<br>• Familiar with managing contractor safety for operations<br>• Familiar with SAFE-3001S<br>• Familiar with SAFE-1005S, “Personal Protective Equipment (PPE) Standard”<br>• Familiar with RISK-1002S, “Visitor Access Control Standard”<br>• Familiar with Cal/OSHA safety regulations and requirements | • Inspector (including contract inspectors)<br>• Construction and/or maintenance crew lead | • SELECTS the project team<br>• DETERMINES the level of contractor oversight needed. This process includes the:<br>  • Scope of work and associated risks<br>  • Potential for hazard exposure to anyone on or near the job<br>  • Conditions required by SAFE-3001S.<br>  • Worksite location<br>  • Site access<br>  • Environmental stewardship<br>  • Available local knowledge regarding operational issues<br>  • Other site-specific information<br>• In conjunction with the resource manager, the regional construction manager, or supervisor,<br>• DETERMINES the size and make-up of the field oversight staff according to the project size and risk level of the project hazards<br>• PROMOTES a safe work environment by ensuring that the contractor and the project team, at a minimum, clearly understand the roles and responsibilities related to:<br>  • Reviewing drawings<br>  • Identifying known hazards<br>  • Communicating policies, standards, and procedures applicable to the work<br>• PROVIDES timely notification to management and the safety team about any safety issues<br>• ENSURES that a thorough initial tailboard is conducted by the contractor using the Site Specific Safety Plan (SSSP) and Job-site Safety Analysis (JSSA)<br>• Performs periodic safety observations<br>• As a Point of Contact, enters post project or at a minimum annual safety performance evaluations in ISN |

**Table 2. Contractor Safety Oversight Program Responsibilities - Continued**

| Personnel | Description | Qualifications | Typical Job Titles | Responsibilities |
|---|---|---|---|---|
| Qualified Site Representative | Same as Competent Site Representative | • Has formal training to identify and mitigate hazards associated with specific high-risk activities<br>• Has formal training in risk evaluation, safety management, and incident cause evaluation per Utility Standard GOV-6102S, "Enterprise Causal Evaluation." | • Inspector (including contract inspectors) | • Same as Competent Site Representative |

2.3 Contractor Representatives and PG&E Safety Representative

1. See Table 3.

**Table 3. Contractor Representatives and PG&E Safety Representative**

| Representative | Description / Responsibilities |
|---|---|
| Contractor Representative and Contractor Safety Representative | • Safety representative is anyone the prime contractor appoints as responsible for the health and safety of all personnel within the contractor's area of control.<br>• Either representative ensures compliance with PG&E and regulatory requirements specific to a facility, location, and site.<br>• Contractor must review and understand the roles and responsibilities outlined in the contract documents and the contractor's safety plan. |
| PG&E Safety Representative | • Typically, a member of the Corporate Safety and Health organization or Gas construction organization, (e.g. safety specialist)<br>• Responsibilities are outlined in SAFE-3001S and include:<br>  • Ensuring required conditions for contractors/subcontractors are communicated to the project team.<br>  • Compliance measures are in place.<br>  • Support for this activity is typically provided by corporate contractor safety, Gas operations contracts, and/or sourcing. |

2.4 Project Team

1. The project team may consist of personnel from operations, maintenance, engineering, project management, transmission and distribution (T&D) construction, inspection, or others as needed.

2. ANYONE working on the site has the authority and responsibility to stop work if unsafe conditions develop.

    a. All project team members may view Construction Onboarding Modules 1, 2, and 3 in Veriforce.

3. The project team:

    a. Identifies institutional knowledge of the facilities related to the work.

    b. Provides input in identifying the risks associated with the specific project work.

    c. Identifies applicable PG&E-specific policies and procedures to follow.

    d. Provides engineering review to support safe project implementation.

    e. Responds in a timely manner to requests and is accountable for their commitments and deliverables.

    f. Clarifies PG&E versus contractor scope.

    g. Conducts safety observations in the field.

    h. Inputs post project or at a minimum annual safety performance evaluations in ISN.

2.5 Management

1. Gas operations directors, managers, and supervisors in each organization utilizing contractors endorse and support gas operation's application of this utility procedure as well as SAFE-3001S.

2. Additional specific responsibilities include:

    a. Participating in pre-construction safety meetings as appropriate.

    b. Providing an avenue for escalation of safety issues.

2.6 Contractor

1. PG&E contractors are responsible for their Site-Specific Safety Plans (SSSPs) or Programmatic Safety Plans (PSPs) and safety processes.

2. Safety may not be compromised for any reason at any time.

3. Contractor must aim for zero safety-related incidents, including, but not limited to the following:

   a. Zero Notices of Violations (city, county, state or federal environmental regulations)

   b. Zero motor vehicle incidents

   c. Zero public safety-related incidents

   d. Zero injuries to personnel working at the site that result in a Recordable Incident or Lost Work Day

   e. Zero gas dig-ins, gas releases, or interruptions of service

4. Contractors must ensure all their employees and subcontractor personnel understand that they:

   a. Have the authority to “Stop Work” due to any unsafe work processes or hazards or sub-standard quality work.

   b. Will not, in any way, adversely affect the requestor’s work status or job security (i.e., they will be protected from any/all potential retribution) for stopping work.2.6 (continued)

5. The contractor’s SSSP or PSP must fulfill PG&E safety program requirements cited in the Master Service Agreement and CWA Safety Documents, including, but not limited to:

   a. MSA Specification #13024 (March 15, 2009)

   b. MSA Attachment 2-General Conditions (June 22, 2009)

   c. Safety document titled “Excavation Procedures for Damage Prevention – TD-4412P-05” (if excavating)

   d. Safety document titled “Site-Specific Safety Plan” or “Programmatic Safety Plan”

6. A SSSP or PSP must be completed by High Risk Contractor. SSSPs are for large contractor projects with limited PG&E oversight. PSPs are for contractors typically working as a sub-contractor to a PG&E crew performing routine tasks.

7. Contractor may only mobilize or start work until AFTER:

a. Submitting an SSSP or PSP to the appropriate PG&E construction or maintenance and construction (M&C) and to the Gas construction safety department management teams per instructions in the “Submittals” paragraph of the Project Specific Information section of the contract

b. The SSSP or PSP has been reviewed and approved by PG&E’s construction or M&C and safety department management teams.

8. Should a safety incident occur, the contractor must notify PG&E staff **in the following order:**

a. Construction manager/On-site PG&E Person in Charge (Supervisor or Foremen)

b. Regional construction manager (if applicable)

c. Gas division safety manager

d. Safety Specialist

e. Project manager

9. IF the contractor has any questions regarding PG&E safety procedures and/or safety requirements,

THEN the contractor must contact the PG&E construction or M&C representative for guidance and clarifications.

10. PG&E’s primary point of contact (POC) for both technical and safety-related matters must be the PG&E construction manager, or the appropriate general construction (GC) or M&C representative.

11. The contractor must maintain records at the job site as described in the SSSP.

12. SSSP Submittal Requirements:

a. SSSP must be submitted and approved prior to start of the work in the field.

- Instructions for uploading safety plans and downloading PG&E safety requirement documents from the Unifier system are defined in PSI Attachment entitled “Access Instructions for PG&E Unifier Document Management System.”

b. Contractors will brief all their personnel and sub-contractors on the SSSP and required mitigation methods, including updating same personnel on all plan changes.

c. Continuously update the SSSP throughout the course of the project, as required, to identify new hazards and incorporate new safety-related activities.

d. All costs associated with mitigating site safety hazards and implementing required safety requirements per the SSSP must be included in the contractor's project proposal price.

13. PSP Submittal Requirements:

a. PSP must be submitted and approved prior to start of the work in the field.

- ISN will send all High-Risk Contractors a PSP template that must be uploaded to ISN for PG&E review.

b. PSP will include Leadership commitments, contact information; typical hazards associated with their work and mitigation measures to address the hazards.

c. PSP must be reviewed and approved on an annual basis by the department that uses the contractor the most.

14. The PG&E Safety Department staff will:

a. Periodically check to ensure job sites are safe and to verify that the contractors are adhering to their approved SSSP or PSP.

b. PG&E Safety Representative shall audit at least 20% of the current High Risk contractors annually to ensure their SSSP or PSP is approved and work being performed is covered in the document under hazard mitigation section.

c. Provide the contractor's management team with a site inspection summary that includes a list of any safety program shortcomings noted during the site check.

The summary will include guidance regarding corrective and preventive actions the contractor must immediately implement to correct noted shortcomings.

15. The contractor must:

a. Include comprehensive incident analysis with corrective and preventive action report.

b. Notify the PG&E Safety Management team, in writing, when all required actions have been completed.

c. Contractors' required reporting of significant safety-related incidents/events is shown in Table 4.

2.6 (continued)

**Table 4. Safety-Related Event Reporting Timelines**

| Safety-Related Event | Verbal Reporting Time Deadline | Written Report Deadline |
|---|---|---|
| Death/Injury of site workers or public person | Immediately | 24 hours |
| Near-Hit Incidents | 24 hours | 24 hours |
| Gas Line Strike or Damage | [redacted] | 24 hours |
| Discovery and Mitigation Methods of Newly Identified Site Hazards | 72 hours | 5 work days |
| Damage to Public or Private Property | Immediately | 24 hours |

16. The prime contractor is responsible for any work done over due to contractor or sub-contractor negligence, unsafe work procedures, or faulty materials/workmanship.

17. The contractor must write emergency plans, if applicable to the work, to cover actions required for:

    a. Emergency Medical Care

    b. Excavation/Trench Rescue (i.e., “Cave-Ins”)

    c. Confined Space Plan

    d. HAZMAT Spill Response Plan

18. Each of above emergency plans must meet federal, state, and local requirements.

19. Emergency plans for items (b), (c), and (d) above will be kept at the contractor’s on-site office for review by PG&E management staff.

20. Site emergency plans must include the names and contact information for key contractor and PG&E personnel as shown in the PG&E site safety plan format.

2.6 (continued)

21. Stop Work Authority

a. Any PG&E or contractor employee on any project site is granted the right to stop any unsafe or sub-standard quality work.

b. This stop work authority must be clearly communicated to every worker via the onboarding process.

**NOTE**

*Contract Precedence—Conflict in Safety Requirements.*

Any PG&E safety requirements cited in the Project-Specific Information sheet or Unifier System Safety Requirement documents supersede those in the MSA agreements.

## 3 Managing Contractor Safety on Larger Projects (> $1M in Contractor Costs)

### 3.1 Pre-Construction

1. Contract management (CM) (see SAFE-3001S, Sections 2.2. through 2.26)

a. Creates a well-defined scope of work to aid with job hazard assessments.

b. Supports supply chain personnel OR an authorized PG&E procurement representative to evaluate and select contractors, based on pre-qualification requirements in SAFE-3001S.

c. Partners with safety representative OR a third-party expert to establish PG&E requirements, regulatory requirements, and control measures to eliminate or mitigate hazards specific to the job before starting work.

d. Verifies that contractors have:

- Completed PG&E's pre-qualification process before starting work. In emergency/emergent work situations (see SAFE-3001S, Section 4).
- Established criteria to meet or exceed PG&E's minimum field oversight expectations (see SAFE-3001S, Appendix A, "Risk and Oversight Matrix") and have also completed PG&E's pre-qualification process before starting work.

3.1.1 (continued)

e. Partners with supply chain personnel OR authorized PG&E procurement representative to submit a Governance Request for contractors/subcontractors that **do not** meet PG&E's pre-qualification safety criteria (see SAFE-3001S).

2. Gas Operations PMO, Construction Management (CM), and Contracts in collaboration with sourcing ASSIST in determining the type of contract, identifying vendors, scheduling, and developing the contract package.

**NOTE**

The steps required to ensure a safe work environment vary depending on the unique circumstances of each job. Factors to consider include:

- Work scope
- Location
- Available knowledge
- Potential exposure and risk associated with the work and PG&E assets

3. The project team completes the following pre-construction activities:

a. Defines the scope of work and the applicable PG&E policies, procedures, standards, permits, and drawings for inclusion in the contract package.

b. Issues and utilizes the following documents to oversee the contract work:

Discipline-specific "Contractor Safety Checklists" (Attachments 1 – 6)

c. Confirms if any proposed contractors or subcontractors have conditional approval to perform work per SAFE-3001S .

d. Provides applicable conditions for approval per SAFE-3001S to site representative before starting work.

e. Ensures an SSSP is developed and available to the site representative before starting work.

3.1.3.e (continued)

**NOTE**

Items (1) and (2) below are not all-inclusive nor do they replace the contractor's own safety program.

PG&E may share safety information with a contractor to protect PG&E personnel, contractor employees, the general public, and property from injury and damage.

Contractors are independent agents and must plan and conduct the work to safeguard persons and property.

- The discipline-specific JSSA/SSSP must be filled out and communicated at a tailboard with the contractor and PG&E employees involved in the work before starting physical work.
- The SSSP identifies potential hazards or issues that could be encountered in performing the work.

4. Contractors are responsible for the following:

   a. Safely performing work.

      - PG&E remains responsible at all times for ensuring compliance with applicable California Public Utilities Commission safety rules and regulations.

   b. Before contractors or subcontractors start work on PG&E facilities, the PG&E site representative must confirm that the contractor and subcontractors have completed the following:

      - All contractor employees and their sub-contractors have completed and passed Contractor Onboarding Modules 1.0, 2.0, and 3.0 in Veriforce.
      - A contractor SSSP has been submitted to and accepted by PG&E, which includes, at a minimum, the following:
        - Plan to implement all work in accordance with all local, state, federal, and PG&E-specific safety regulations.
        - Before starting work, contractors must identify work tasks, associated hazards, and actions to be taken by the contractor to prevent injuries.
        - Contractor is required to communicate and ensure adherence to applicable policies, standards, procedures, specifications, drawings, and conditions of the contract.

3.1.4.b (continued)

- Plan to immediately notify the PG&E site representative of any injury or medical emergency that occurs while on PG&E property.
- Contractor must provide a written incident report within 24 to 72 hours including a causal analysis as defined in this document.

- Prior to commencement of work, the PG&E safety representative and PG&E site representative:
  - Review the adequacy of the safety plan, including contractor safety personnel qualifications where applicable.
  - Perform a safety assessment to evaluate whether additional safety mitigations are required.
  - IF the project team determines that additional expertise is required,

    THEN PG&E will engage third-party experts to perform the analysis.

5. Hazard Communication – Work-site Awareness

   a. All visitors, contractors, sub-contractors, PG&E employees and members of the public shall be informed of hazards before the commencement of work.

3.2 Pre-Construction Safety Meeting/Safety Kick-Off

1. For all major construction projects that are led by an outside contractor, the PG&E site representative will participate in the pre-construction safety meeting before a contractor mobilizes to the project site.

   a. Meeting includes the PG&E project team that is responsible for contractor oversight.

   b. Contractor keeps and manages sign-in sheets for this kick-off meeting. The attendees for this meeting include the following:

      - Contractor and their sub-contractors
      - Project manager
      - PG&E site representative
      - PG&E safety specialist
      - Area project engineering supervisor

3.2.1.b (continued)

- Representative from PG&E's Corporate Contractor Safety group (optional)
- Director of project execution and the manager of project engineering (optional)

c. The agenda for the kick-off meeting must include, but is not limited to:

- Reviewing the daily JSSA requirements.
- Discussing roles and responsibilities for each team member.
- Discussing construction safety risks and how they will be mitigated.
- Reviewing and verifying a communication plan relative to safety.
- Creating field work notifications and an emergency response plan.

## 4 Construction

### 4.1 Construction Oversight

The PG&E site representative:

a. Observes the contractor's adherence to contractor's safety plan, daily JSSA, and general safe practices.

b. IF the PG&E site representative OBSERVES unsafe practices or a violation of the contractor's safety plan or JSSA,

THEN the PG&E site representative STOPS the activity or all work on the project if necessary, until the contractor develops and implements corrective actions and communicates corrective actions to the on-site team.

**NOTE**

It is everyone's responsibility to escalate a safety concern if they believe corrective actions have not properly addressed safety concerns.

c. Communicates the safety issue per PG&E's safety reporting requirements.

d. Actively participates in the daily tailboard meetings led by the contractor to ensure that:

4.1.d (continued)

- Safety is planned for the day.
- The contractor's JSSA addresses all foreseeable hazards associated with the activities planned for the day.

  The discipline-specific SSSP is used as a reference to identify potential hazards that must be addressed.
- Changed conditions are identified and addressed in the contractor's safety plan.
- Best practices are discussed and incorporated.

e. Acts as the sole representative of PG&E on site in relation to all matters of public and worker safety, as well as quality of work.

f. Interfaces with agencies, government representatives, other utilities, local communities, businesses, institutions, customers, first responders, and law enforcement representatives.

g. Ensures compliance with all permit conditions.

h. Can be a PG&E employee or consultant/contractor hired by PG&E to represent PG&E on site.

i. In a case of an emergency arising on site, the PG&E site representative immediately assumes command of the incident and becomes the incident commander (IC) managing the incident until relieved by Operations Emergency Center (OEC) personnel. As such, the PG&E site representative will initiate all appropriate actions listed in the Gas Emergency Response Plan (GERM) to ensure workers' and public safety.

j. Wears PG&E branded Personal Protective Equipment (PPE) at all times to ensure they are easily and readily identifiable by first responders, law enforcement agencies, other utilities and local government as the PG&E representative on site. This requirement applies to PG&E employees and consultants/contractors (i.e. inspectors or construction managers) hired to represent PG&E on site.

4.2 Field Safety Observations

1. The worksite team participates in periodic field safety observation to be supported by the PG&E safety representative.

2. The PG&E site representative notifies the PG&E safety representative of the project construction schedule before construction begins.

3. The PG&E safety representative:

   a. Develops the field safety observation criteria.

   b. Ensures observations are performed in accordance with the set frequency. Refer to the table below:

| Field Safety Observations – Frequency Requirements | | |
|---|---|---|
| **Risk** | **Work Description** | **How Often?** |
| High* | • Tasks that meet the criteria for high risk per Table 1 Risk and Oversight Matrix. | 1 per week |
| Medium** | • Tasks that meet the criteria for medium risk per Table 1 Risk and Oversight Matrix. | 1 per month |

* A minimum of ONE observation per week will be required for ANY (not each) of the High-Risk Gas Contractors for a total number of documented safety observations on High Risk Contractors of 52 per year.

** A minimum of ONE observation per month will be required for ANY (not each) of the Medium Risk Gas Contractors for a total number of documented safety observations on Medium Risk Contractors of 12 per year.

Gas will therefore perform and document a minimum total number of safety observations of 64 per year as detailed above.

4. After completing the field safety observation, the PG&E site representative and the PG&E safety representative REVIEW the results of the field safety observation with contractor's site representative.

5. PG&E may require the contractor to develop an action plan to address any field safety observation issues, especially if they are significant or systemic issues.

6. The contractor site representative CAPTURES best practices and SHARES them with the contractor team for implementation.

7. The PG&E safety representative DOCUMENTS the contractor's completion of action items resulting from the field safety observation.

## 5 Post-Construction

5.1 The PG&E site representative ENSURES that the Contractor Performance Evaluation Form is completed for major projects and is uploaded to Unifier.

   a. The form must be completed in a timely manner at the completion of construction activities on major projects, or annually for multi-year projects.

5.2 Post-construction lessons learned meeting is conducted and documented in Unifier on major projects.

5.3 All contractor performance must be entered into ISN. The frequency is determined by the business unit, but must be done annually at a minimum.

## 6 Documentation

6.1 The PG&E safety representative collects all safety related documentation and includes it in the final inspection report to be filed on the shared drive and Unifier.

6.2 The final safety-related documentation must include, but is not limited to, the following:

a. Site Specific Safety Plan

b. Documentation of all certifications and qualifications for site personnel

c. Safety incident analysis reports

d. Safety Quality Good Catch Forms (near- hit)

e. Daily tailboards and JSSAs

f. Field safety observation documentation

g. Contractor Project Specific Performance Evaluations (see Attachments 5, 6)

6.3 The PG&E safety representative ENSURES that the appropriate safety-related documentation is properly filed.

6.4 Recordkeeping

- Retain records per the record retention schedule.

## 7 Managing Contractor Safety on Smaller Projects (< $1M in Contractor Costs) or Sub-Contractors supporting Maintenance and Construction Operations

7.1 Minimum Requirements

1. On smaller projects, the Gas responsible leader (director, manager, superintendent, and supervisor) overseeing the work ensures the following minimum requirements are met:

a. The scope of work is clearly defined for all parties through the Contract Work Authorization (CWA) or Blanket Purchase Order (BPO).

b. Qualified, trained contractors are selected.

c. Safety hazards are identified and communicated effectively between all parties involved through a tailboard or review of the contractor’s PSP.

d. Contractors develop, implement, and adhere to comprehensive safety plans that address the unique challenges of working on PG&E's natural gas facilities.

e. Proper job safety oversight is provided.

7.2 Specific Requirements

1. The responsible Gas leader reviews each project to determine the specific level of oversight according to project risk.

**NOTE**

All of the processes and forms used for larger projects may also be used for smaller projects. Variations of these forms may be used to document risk identification and mitigation measures and to demonstrate that all of the above minimum requirements (Section 6.1, 1 through 5) have been met.

2. At a minimum, the responsible Gas leader ensures the following:

a. The job scope is understood by all parties.

- The contractor's scope of work is clearly defined, including distinguishing between contractor's responsibilities and PG&E's responsibilities.
- The contractor's field supervision clearly understands this scope of work prior to start of contractor field activities.
- The scope of work must be clearly communicated and understood as part of project kick off meeting if one occurs or at a minimum as part of the JSSA.

b. Qualified, trained contractors are selected.

- Only PG&E approved contractors may perform the work.
- This requirement specifically includes contractors with an acceptable status in ISN and Gold Shovel Program (if contractor performs excavation activities).
- Governance may be required for contractors with sub-par grades in ISN or Gold Shovel.

c. Safety hazards are identified and communicated effectively to all parties involved.

- This includes specifically holding a project kick off meeting or, at a minimum, a JSSA and tailboard, to review:

- The project scope of work.
- All hazards associated with the work.
- Permit conditions.
- Applicable PG&E safety policies.
- The PG&E SSSP, if one has been prepared for the project.
- The emergency response plan.

- Place special emphasis on:
  - The right and obligation to stop unsafe work.
  - Requirements for completing and documenting a JSSA and holding safety tailboards with the entire job crew on a daily basis, at the start of the shift, or more frequently whenever conditions change. **NOTE**: For contractors transporting hazardous materials (for example, LNG/CNG), refer to attachment 7 for guidance.
  - The requirement to keep records of all projects and JSSA/safety tailboards and make them available to PG&E if requested.
  - An emergency response plan for each project, including providing closest medical facility and jobsite address. This notification may take the form of a white board placard on the back of a crew truck.
  - The obligation to report all safety incidents as outlined in Table 3 above including Attachment.4, “Incident Report Form.”
  - The requirements of the “Emergency Notification,” process (Table 4) and the communication of Gas Control Emergency phone numbers for reporting any dig -ins or gas leaks.
  - The requirement that appropriate personnel on-boarding is completed and documented as determined by the responsible Gas leader. This can include a kick-off project tailboard to on-board contractors. On-line on-boarding, a video or job-walk prior to the start of work are all acceptable means of on-boarding a contractor to discuss the specific hazards associated with the project or task.

d. Contractors:

- Develop, implement, and adhere to comprehensive safety plans that address the unique challenges of working on PG&E's natural gas facilities.

- Conduct a JSSA and safety tailboard with all construction personnel at a minimum once daily at the beginning of every shift or whenever conditions change.

- Retain all projects' JSSAs/safety tailboards onsite during the project and for a minimum of 36 months after the project is completed. These records will be made available to PG&E personnel whenever requested.

3. Ensures proper job safety oversight is provided.

   a. The responsible Gas leader:

   - Provides adequate job safety oversight depending on project risk and duration

     - This oversight may include, as needed, full time safety oversight or may include regular, spot, or random individual jobsite, job bundles, or program visits as determined on a case by case basis.

   - Visits worksites and performs regular or randomized safety observations suitable for the work performed. At a minimum, these observations ensure:

     - Adequate JSSAs are completed daily/per shift and are followed by the contractor(s). **NOTE**: For contractors transporting hazardous materials (for example, LNG/CNG), refer to attachment 7 for guidance.

     - All applicable safety policies are being followed, including Cal/OSHA and PG&E policies as well as the SSSP if one exists.

     - An excavation competent person is on site 100% of time anytime excavation work is being performed or personnel are working inside excavations.

     - The field visit and safety observation is documented in a suitable tool. PG&E Guardian tool, Attachment 4, or other suitable tools may be used for this purpose.

- A suitable Contractor Performance Evaluation (Attachment 5) is conducted, documented, and shared with the contractor at the end of each project or group/bundle of small jobs or other suitable interval.

  For groups of smaller jobs, one contractor evaluation per region per quarter is suggested.

- Verifies an adequate emergency plan exists.

- Confirms that field employees understand the emergency plan

## 8 Managing Transportation of LNG/CNG or other Hazardous Materials

8.1 Projects over or under $1M apply to LNG/CNG operations. Section 8 pertains to the oversight requirements related to transporting LNG/CNG to worksites and other locations.

8.2 Requirements for completing and documenting a JSSA and conducting a tailboard are required for all transport operations. For more details refer to attachment 7 – JSSA Matrix for LNG/CNG transportation operations.

**END of Instructions**

## DEFINITIONS

**Causal Analysis** – An evaluation of all factors that contributed to an incident. There may be one or more causal factors, and each factor must be analyzed to determine why that causal factor occurred. Elements that may be considered include, but are not limited to the following: personnel/staffing, leadership, equipment, environment, policies, and procedures. A causal analysis does not necessarily lead to a single root cause, but should generate corrective actions to address each causal factor.

**Competent Site Representative –** A designated individual, typically a supervisor or regional construction manager, authorized to make decisions impacting safety, schedule, production, and project costs.

**Contractor –** A company directly hired by PG&E to complete a specific scope of work or service. Throughout this document, references to contractor include all subcontracted resources.

**Contractor Site-Specific Safety Plan (SSSP) –** Detailed safety plan created by the contractor to eliminate or mitigate specific job site environmental, health, and safety hazards associated with the scope of work. In this document, the SSSP is referred to as the “contractor safety plan.”

## Contractor Safety Oversight Procedure – Gas Operations

**High Risk Contractors –** Contractors or subcontractors performing work that directly exposes their employees to PG&E systems, assets, or processes associated with Power Generation, Gas or Electric transmission or distribution operations. This term also includes contractors whose work requires any of the following:

- Bodily entry into a confined space or hazardous environment.
- Applying lockout/tagout (LOTO) devices as part of hazardous energy control
- Working at a height that requires the use of fall arresting equipment
- Entering an excavation greater than 4 feet deep
- Demolition activities
- The use of explosive devices
- Commercial diving
- Aviation services
- Vegetative management beyond weed control
- Handling or transporting hazardous chemicals.

**Job-Site Safety Analysis (JSSA)** – Identifying hazards, evaluate and prioritize the hazards for control, select appropriate controls, and evaluate the controls for any given job task to improve work practices and promote a safe work environment.

**Low-Risk Contractor –** Contractors or subcontractors NOT working on or exposed to any hazards associated with Power Generation, Gas or Electric transmission or distribution processes or process-related equipment or working within designated construction areas. These contractors are exempt from this utility procedure and its standard. Work requires minimal planning, preparation, formal training, or work controls.

**Medium Risk Contractor–** Contractor whose work requires advanced planning, preparation, formal training, work controls, and audit/oversight, or specialized personal protective equipment (PPE) beyond hardhat, safety glasses, safety toed footwear or high visibility vests. Contractors or subcontractors that do NOT meet the definition of high or low risk

**Near-Hit –** An unplanned event that did not result in injury to employees, contractors, or the public, and did not result in damage to Company assets

Examples of near hits include potential

- Disruption of service
- Personal safety or hazardous conditions, such as driving

**PG&E Safety Representative –** PG&E individual recognized by degree, certification, knowledge, or experience as a health and safety subject matter expert (SME) who has decision-making authority for ensuring safety compliance.

**Responsible Gas Leader –**The PG&E Gas director, manager, superintendent, supervisor, or his delegate who the work is being performed for and/or who has been appointed to oversee the work.

**Safety and Quality Good Catch –** A proactive approach to identify safety or quality issues that include stopping any unsafe or non-quality work or activity and coaching a fellow team member

**Stop Work –** Deliberate act of stopping work to eliminate or effectively control unsafe work or sub-standard quality work, practice, or behavior.

## IMPLEMENTATION RESPONSIBILITIES

Directors and managers/ superintendents in Gas operations are responsible for communicating and implementing this procedure within their respective organizations and for ensuring it is being adhered to going forward.

## GOVERNING DOCUMENT

SAFE-3001S, “Contractor Safety Standard”

## COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

Cal/OSHA Title 8 Regulations

## REFERENCE DOCUMENTS

**Developmental References:**

Cal/OSHA Form 301, “Injury and Illness Incident Report”

LAW-2001S, “Contracting Requirements Standards”

PG&E’s *Code of Safe Practices*

PG&E’s Hazard Reference Guide for Contract Work

PG&E’s *Procurement Manual*

SAFE-1001S, “Safety and Health Program Standard”

TD-4412P-05 – Excavation Procedures for Damage Prevention

**Supplemental References:**

N/A

**APPENDICES**

Appendix A, "Process Map"

**ATTACHMENTS**

Attachment 1, "Site Specific Safety Plan Template"

Attachment 2, "Incident Report Form

Attachment 3, "Good Catch/Quality Catch/Near Hit"

Attachment 4, "Sample Safety Checklist/Observation Form"

Attachment 5, "Sample Contractor Project Specific Performance Evaluation in Unifier"

Attachment 6, "Job Aid for Completing Gas Contractor Safety Evaluation in ISN"

Attachment 7, "Sample Lessons Learned Form"

Attachment 8, "JSSA Matrix for LNG/CNG transportation operations"

**DOCUMENT RECISION**

NA

**DOCUMENT APPROVER**

Jesus Soto, Jr – Sr. VP, Gas Operations

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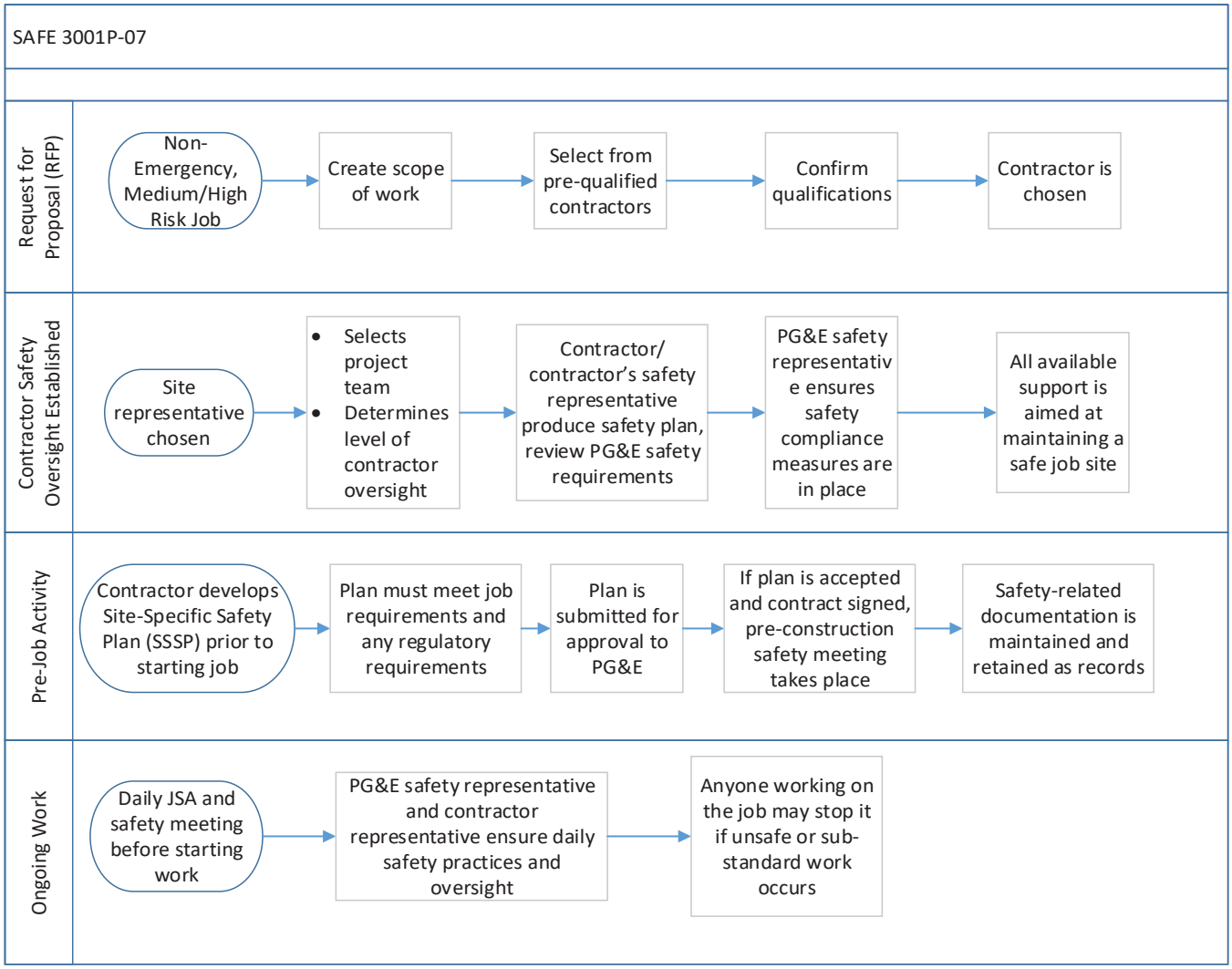
# Contractor Safety Oversight Procedure – Gas Operations

## REVISION NOTES

| Where? | What Changed? |
|---|---|
| Table 2 | Added to the list of responsibilities of the Competent Site Representative |
| Section 2.4, number 3 | Added to the list of project team responsibilities |
| Section 4.2 | Updated contractor safety observations criteria |
| Attachments | Added attachment 6 for contractor safety evaluations in ISN |
| Section 4.1 | Added requirements for PG&E Safety Representative |

# Contractor Safety Oversight Program Gas Operations

## Appendix A, Process Map



**PACIFIC GAS AND ELECTRIC COMPANY**

**ATTACHMENT 9**

**Station Critical Documentation: Utility Standard TD-4551S, Rev.2**

**PUBLIC VERSION**

Pacific Gas and Electric Company®

Utility Standard: TD-4551S
Publication Date: 06/21/2017; Effective Date: 08/20/2017 Rev: 2

# Station Critical Documentation

## SUMMARY

This utility standard describes critical documentation required for the safe and reliable operation and maintenance of gas transmission facilities and certain gas distribution facilities. This utility standard also establishes categories to organize facilities into groups sharing common sets of required critical documents.

## TARGET AUDIENCE

All gas engineering and design, facility engineering, pipeline engineering, mapping, operations, maintenance, integrity management, and process safety personnel, as well as personnel responsible for the management and engineering of projects affecting gas transmission facilities, large volume customer regulator (LVCR) sets, and district regulator stations.

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## REQUIREMENTS

### 1 Roles and Responsibilities

1.1 The Facility Integrity Management Program (FIMP) organization is responsible for assigning and re-assigning facility categories, and ensuring that the required critical documents for each categorized facility are prepared, completed, and aligned with the current state of the facility. In addition, FIMP personnel are responsible for approving and managing additions or exceptions to the required critical documentation for any specific facility, and determining whether a facility can be excluded from the requirements of this utility standard.

1.2 Project managers (PM) and project engineers (PE) of projects that affect facilities are responsible for overseeing and budgeting for creation or update of critical documents. This includes system-wide projects performed by the business, such as valve automation, strength testing, and pipeline modifications that allow in-line inspection (ILI). The PM and PE responsibilities include requesting FIMP approval of any exceptions to this utility standard. The PM is responsible for ensuring that the timely and complete submittal of all as-built records, per Utility Standard TD-4461S, "Gas As-Built Packages," includes all affected critical documents identified in this utility standard.

1.3 Assigned station gas pipeline operations and maintenance (GPOM) operators are responsible for identifying any observed inaccuracies or incompleteness within critical documents, either though the Corrective Action Program (CAP) or written communication with the facility's assigned facility engineer (FE) or pipeline engineer (PLE).

1.4 Each facility's assigned FE or PLE is responsible for ensuring that required critical documents for that facility are maintained. The assigned FE or PLE may request exceptions or additions to the critical documents for a specific facility; however, deviations from this utility standard require written approval from a FIMP manager.

1.5 Gas engineering and design personnel are responsible for the timely issuance and correction of issued-for-use/construction and as-found critical documents. If proposed project changes are not executed to an existing facility, then gas engineering and design personnel must retract the issued-for-use/construction documents that do not accurately represent the existing facility.

## 2 General Requirements

2.1 This utility standard uses the general terms "station" and "facility" interchangeably, for the sole purposes stated within. These terms may have general or very specific meanings in other Pacific Gas and Electric Company (PG&E or Company) governance documents, Federal and State codes and regulations, and industry standards and design codes. The descriptions, boundaries, or categorization of facilities and stations within MUST NOT be used as a basis to identify or classify facilities or stations outside of the scope of this utility standard. Therefore, this utility standard MUST NOT be used for the application of station piping design factors, determination of piping scopes within pipeline or station features lists (PFLs or SFLs), assignment of asset ownership within PG&E (e.g., transmission or distribution), determination of piping scopes associated with demonstrating regulatory compliance, or similar implementations.

2.2 Except as provided in Paragraph 2.6, this utility standard applies to Company gas transmission (GT) facilities and certain gas distribution (GD) facilities, and requires specific documentation deemed critical to help ensure safe and reliable operation and maintenance of the facility. As such, the critical documentation identified for each station category must provide accurate information regarding installed piping and equipment, and continue to be updated in a timely manner. (Refer to Section 5 for update considerations.)

2.3 The documentation requirements in this utility standard add to other Company requirements for facility documentation, such as the generation and retention of strength test pressure reports, weld summary reports, and equipment maintenance reports, and other Company requirements for system documentation, such as the Gas Emergency Response Plan (GERP). The identification of certain documents as “critical” does not relieve or reduce the significance of the many other documents associated with the design, construction, operation, and maintenance of gas facilities.

2.4 FIMP personnel assign each gas facility (except those excluded under Paragraph 2.6) a facility category corresponding to its design and operating functions. The specific critical documents required are determined by the facility category. The levels of complexity among applicable facilities within a category can vary considerably, and therefore the level of detail within each required document type can vary considerably.

2.5 Storage facilities, compressor stations, and Category A stations are required to have main gas piping drawings in accordance with Paragraph 4.9. All facilities requiring critical documents must be in accordance with this utility standard by 06/30/2021.

**NOTE**

LNG/CNG facilities are out of scope because they operate under a set of regulatory requirements different from those governing gas transmission and distribution facilities. The same critical documents specified in this utility standard may also be considered critical to help ensure safe and reliable operation and maintenance of comparable LNG/CNG facilities. Such determination for applicability, including review for regulatory compliance, is outside of the scope of this utility standard.

2.6 **Excluded Facilities:** Certain facilities are excluded based on their functional and operational characteristics. The following facilities are generally excluded from the documentation requirements of this utility standard:

1. LNG/CNG facilities
2. Transmission pipeline sections that exist between stations
3. Transmission valve lots, crossties (or crossovers), and other similar facilities that do not have pressure control or regulation devices
4. Gas gathering pipelines and facilities
5. Distribution pipelines and facilities other than district regulator stations and LVCR sets (including distribution assets located within gas transmission facilities)
6. Farm tap regulator sets

## 3 Facility Categories

3.1 Categories are assigned to facilities under the direction and approval of a FIMP manager, based on the following general process:

1. Initially, numbered drawings of transmission facilities are reviewed in order to assign the appropriate category for each facility, or exclude the facility as described in Paragraph 2.6. If a facility's functional or operational characteristics are not sufficiently depicted on numbered drawings to clearly exclude it, or to distinguish between categories, then the more conservative category is assigned.

2. Category assignments for transmission or distribution facilities not currently shown on numbered drawings are based on their general identification provided by other company records, such as SAP for district regulator stations and asset knowledge management (AKM) records for LVCR sets.

3. Facility projects that potentially change the category must be identified by gas engineering and design personnel, and reviewed by a FIMP manager during the project proposal phase. Categories are reassigned after project execution, as directed by a FIMP manager.

3.2 **Storage Facilities:** Transmission facilities that store, pressurize, and process gas using an underground reservoir formation. Facilities may be unmanned or manned full-time, and may have single or multiple compressor units for injection. Facilities have gas processing equipment and auxiliary systems and equipment. Facilities within this category are:

1. McDonald Island Gas Storage Facility
   - McDonald Island Compressor Station
   - Whisky Slough Station
   - Turner Cut Station
2. Los Medanos Gas Storage Facility
   - Los Medanos Compressor Station
3. Pleasant Creek Gas Storage Facility
   - Pleasant Creek Compressor Station

## Station Critical Documentation

3.3 **Compressor Stations:** Transmission stations that pressurize natural gas for the purpose of transporting it from one location to another, and are not already included in Paragraph 3.2. Stations may be unmanned or manned full-time, have single or multiple compressor units, and have multiple operating and control modes. The station or individual compressor units may be remotely operated. Stations have auxiliary systems and equipment. Facilities within this category are:

1. [redacted] compressor stations:
   - Hinkley Compressor Station
   - Topock Compressor Station
2. [redacted] compressor stations:
   - Bethany Compressor Station
   - Burney Compressor Station
   - Delevan Compressor Station
   - Gerber Compressor Station
   - Kettleman Compressor Station
   - Santa Rosa Compressor Station
   - Tionesta Compressor Station

3.4 **Category A Stations:** Transmission facilities that have complex controls and operation, such as those designed and constructed per Gas Design Standard (GDS) H-19, "Gas Regulator Stations – Control Valve Systems," excluding facilities meeting the category descriptions for storage facilities, compressor stations, and automated valves (Paragraphs 3.2, 3.3, and 3.6). Category A stations contain controller-operated valves that regulate pressure, and may have a programmable logic controller (PLC) or a remote terminal unit (RTU) providing control and/or data transmission. Examples include:

1. Terminals, which act as hubs to route gas from the backbone transmission lines to local transmission lines:
   - Antioch Terminal
   - Brentwood Terminal
   - Milpitas Terminal

3.4 (continued)

2. Underground gas holders (i.e., fabricated storage):

   - North Sacramento Underground Holder
   - Santa Cruz Underground Holder
   - Yuba City Underground Holder

3. Pressure limiting or regulator stations with load valve/trimmer valve installations or a mix of controller-operated valves and self-contained regulators.

4. Metering stations containing valves that are PLC, RTU, or controller-operated.

5. Interconnect or intertie stations that, regardless of outlet pressure, regulate pressure and contain Company-owned control valves.

3.5 **Category B Stations:** Transmission stations that have simple control and operation. Stations within this category may include instrumentation and RTUs, provided they are for monitoring and data transmission purposes only (i.e., not for control).This category includes transmission stations with regulators that have self-contained controls, such as those designed and constructed per GDS H-10, “High-Pressure Regulator-Type Stations and Farm Tap Regulator Sets,” GDS H-14, “Gas Regulator Stations – Spring-Loaded and Pilot-Operated Systems,” or comparable historic standards. Examples include:

- Interconnect or intertie stations that, regardless of outlet pressure, do not have PLC, RTU, or controller devices that command the position of a Company-owned valve.
- Odorizer, dehydrator, or meter stations that contain only manually-operated equipment and block valves.
- Pressure limiting or regulator stations that contain only spring-loaded or pilot-operated regulators/monitors for control, such as Mooney regulators.

3.6 **Automated Valves:** Transmission mainline valves operated remotely by gas control. Automated valves include remote control valves (RCVs) and automatic shutoff valves (ASVs). This category includes automated valves installed in locations that do not provide regulation. Automated valves located within a facility assigned to a different category are not included in this category. Examples include:

- Automated singular mainline valves along pipeline right of ways
- Remotely controlled intertie stations, regardless of outlet pressure, that do not regulate pressure
- Valve lots or crossties that do not regulate pressure and contain one or more remote valves

3.7 **Large Volume Customer Regulator (LVCR) Sets:** A pressure regulation set, including both single and multiple stages of pressure regulation, which controls pressure to a transmission line serving a large volume customer, sometimes referred to as a customer primary set (see Utility Procedure TD-4125P-10, "Identifying Gas Transmission Assets"). LVCR sets located within a facility assigned to a different category, with outlet pressures above 60 psig, are assigned Category A or B.

3.8 **District Regulator Station:** A pressure regulation station, including both single and multiple stages of pressure regulation, which controls pressure to a distribution main (see Utility Standard TD-4540S, "Gas Pressure Regulation Maintenance Requirements for Self-Operated and Pilot-Operated Regulators"). This category **includes** district regulator stations that are located within a facility assigned to a different category.

## 4 Critical Documents

4.1 With the exception of operating diagrams for district regulator stations, all critical documents identified in this subsection are assigned Company drawing numbers (i.e., numbered drawings). All numbered drawings (or documents) are retrievable via PG&E's system of record, Documentum. If there is a change to a facility category assignment, then any existing numbered drawings that are no longer considered critical must not be obsoleted without FIMP manager approval.

4.2 This section provides high-level descriptions of each critical document type and identifies the facility categories for which that document type is required. The required documents for each facility category, as specified in this section, are also summarized in Appendix A, "Required Documentation Matrix."

4.3 ***Operating Diagram:*** Schematic drawing of a facility that shows incoming and outgoing lines, valves and their normal operating positions, major equipment, supervisory control and data acquisition (SCADA) points, and operating pressure limits and delineations. Operating Diagrams are created and updated by mapping personnel in accordance with written procedures, such as Utility Procedure TD-4460P-10, "Gas Transmission Operating Maps and Operating Diagrams." Operating Diagrams are required for facilities within all categories.

## Station Critical Documentation

4.4 ***Operating and Maintenance Instructions (O&MI):*** Written document that contains all of the following:

1. General information about a facility such as: purpose, location, and operating parameters

2. A description and depiction of the facility's operating and control modes, including abnormal and emergency operating modes

3. A list of all critical documents for the facility (per this utility standard)

O&MIs are created, updated, and maintained in accordance with Utility Procedure TD-4551P-01, "Operating and Maintenance Instructions for Transmission Major Gas Control Stations." An O&MI is required for facilities within the following categories:

- Storage Fields
- Compressor Stations
- Category A Stations
- Category B Stations
- Automated Valves

4.5 ***Operating Procedures:*** Written document that provides detailed procedures for operating systems, processes, or specific pieces of equipment. Operating procedures contain checklists and corresponding piping and instrumentation diagrams (P&IDs) to facilitate their use. Utility procedures published in the TD-4551 series may include additional operating procedure requirements. Operating procedures are required for facilities within the following categories:

- Storage Facilities
- Manned Compressor Stations

4.6 ***Control Philosophy:*** Written document that contains a detailed description and discussion of the operating and control modes of a facility. The control philosophy includes a description of the systems installed to protect the facility if abnormal operating conditions occur. Utility procedures published in the TD-4551 series may include additional control philosophy requirements. A control philosophy is required for facilities that have a PLC, digital control system (DCS), or controlling RTU. A single control philosophy that identifies each applicable automated valve can be used for common Automated Valve facilities. A control philosophy is required for facilities within the following categories:

- Storage Facilities
- Compressor Stations
- Category A Stations that have a PLC, DCS or controlling RTU
- Automated Valves that have a PLC, DCS or controlling RTU

4.7 ***Control System Architecture:*** Drawing that shows, in a single-line format, the interface connections between various system components, including the following:

- Input/output (I/O) devices
- Controlling devices
- Operator interfaces
- Peripheral devices, such as modems and printers
- Linkages to outside networks, such as SCADA.

The control system architecture drawing also identifies the various component platforms and communication protocols. Utility procedures published in the TD-4551 series may include additional control system architecture requirements. This drawing is required for facilities that have a PLC, DCS, or controlling RTU. A single control system architecture that identifies each applicable automated valve can be used for common Automated Valve facilities. A control system architecture drawing is required for the following categories:

- Storage Facilities
- Compressor Stations
- Category A Stations that have a PLC, DCS, or controlling RTU
- Automated Valves that have a PLC, DCS, or controlling RTU

## Station Critical Documentation

4.8 ***Piping and Instrumentation Diagram (P&ID):*** Schematic drawing of the facility showing the process flow along with installed piping and instrumentation equipment. P&IDs identify and tag all pipelines and equipment depicted. Certain facilities, designed to earlier requirements, have elementary mechanical (EM) drawings instead of P&IDs. When project work is done at these facilities, EM drawings must be redrawn as P&IDs. Utility procedures published in the TD-4551 series may include additional P&ID requirements. A P&ID is required for facilities within the following categories:

- Storage Facilities
- Compressor Stations
- Category A Stations
- Category B Stations
- Automated Valves

4.9 ***Main Gas Piping Drawing:*** Plan-view drawing showing the above and belowground layout of the main gas piping within the facility. The main gas piping drawing may include section and detail views in order to clearly show pipe routing. Utility procedures published in the TD-4551 series may include additional main gas piping drawing requirements.

Main gas piping drawings for storage facilities, compressor stations, and Category A Stations also fulfill ground plan drawing requirements stipulated in GO 58A §3.d. Therefore, the main gas piping drawings for stations within these categories must be drawn to suitable scale indicating major piping configurations (including major connections, valves, and equipment) used for the control and delivery of gas. Note that Category A Stations are considered “major gas control stations” only with regards toward demonstrating compliance with GO 58A §3.d.

A main gas piping drawing is required for facilities within the following categories:

- Storage Facilities
- Compressor Stations
- Category A Stations
- Category B Stations
- Automated Valves

## Station Critical Documentation

4.10 ***Equipment List:*** List of all existing process and electrical equipment installed at a facility. The equipment list includes information such as equipment tag number, equipment type, equipment function, manufacturer, model, reference drawing number, and (if it exists) the corresponding SAP Equipment Number. Utility procedures published in the TD-4551 series may include additional equipment list requirements. An equipment list is required for facilities within the following categories:

- Storage Facilities
- Compressor Stations
- Category A Stations
- Category B Stations
- Automated Valves

4.11 ***Line List:*** List of piping and tubing segments within a facility. The segment description and tag correspond to non-electrical line designations in the P&ID. The line list includes information such as the piping or tubing line number, diameter, segment starting and end points, and reference P&ID number. Utility procedures published in the TD-4551 series may include additional line list requirements. A line list is required for facilities within the following categories:

- Storage Facilities
- Compressor Stations
- Category A Stations
- Category B Stations

4.12 ***Electrical Schematic:*** Schematic drawing prepared for all stations with discrete devices (e.g., solenoids or motor starters) that involve complex (e.g., interlocking) hard-wired control logic. They schematically show the logic to operate the discrete devices.

Facilities designed to earlier requirements may still have elementary electrical (EE) drawings in effect that depict similar electrical schematic information. EE drawings are being phased out and replaced by modern electrical schematics, connection diagrams, and electrical single line diagrams, as applicable.

Utility procedures published in the TD-4551 series may include additional electrical schematic requirements. An electrical schematic is required for the following categories:

- Storage Facilities
- Compressor Stations
- Category A Stations that have a PLC

## Station Critical Documentation

4.13 ***Electrical Single Line Diagram:*** Circuit diagram that uses single lines and symbols to indicate the connections to equipment within an electrical circuit. The electrical single line diagram is the primary reference for the set of diagrams used to depict the electric functionality of the facility. The electrical single line diagram, which includes site utility supplies such as lighting, as well as gas asset related supplies, is required for any facility where a voltage is present at 50 volts (V) or above (AC or DC) because these voltages may give rise to danger.

Facilities designed to earlier requirements may still have EE drawings in effect that depict similar single line diagram information. EE drawings are being phased out and replaced by electrical single line diagrams, electrical schematics, and connection diagrams as applicable.

Utility procedures published in the TD-4551 series may include additional electrical single line diagram requirements. An electrical single line diagram is required for facilities within the following categories:

- Storage Facilities
- Compressor Stations
- Category A Stations where voltage is present at 50 V or above (AC or DC)
- Category B Stations where electrical equipment is present and voltage is present at 50 V or above (AC or DC)
- Automated Valves where voltage is present at 50 V or above (AC or DC)

4.14 ***Connection Diagram:*** Drawing showing connections at each wire termination location, such as specified terminal strips. Facilities designed to earlier requirements may still have EE drawings in effect that depict similar connection information. However, EE drawings are being phased out and replaced by modern connection diagrams, electrical single line diagrams, and electrical schematics, as applicable. Utility procedures published in the TD-4551 series may include additional connection diagram requirements. Connection diagrams are required for facilities within the following categories:

- Storage Facilities
- Compressor Stations
- Category A Stations
- Category B Stations where electrical equipment is present
- Automated Valves

4.15 ***Hazardous Area Classification Drawing:*** Drawing that defines the boundaries of National Electric Code (NEC) "classified locations" within a natural gas facility. The hazardous area classification drawing is used for design and maintenance of electrical installations at gas facilities. Utility procedures published in the TD-4551 series may include additional hazardous area classification drawing requirements. A hazardous area classification drawing is required for facilities within the following categories:

- Storage Facilities
- Compressor Stations
- Category A Stations
- Category B Stations where electrical equipment is present
- Automated Valves

## 5 Critical Document Interdependency

5.1 Critical documents for a facility may be interdependent in that the same information may be contained in more than one critical document. For example, a pressure transmitter shown on a P&ID is also included on the equipment list and a connection diagram, and may be contained in a control philosophy, and operating procedure.

5.2 Interdependencies between critical documents are identified in Appendix B, "Critical Document Interdependency Matrix."

5.3 The impact of document interdependency must be assessed as part of change management when creating or revising a critical document.

**END of Requirements**

## DEFINITIONS

**Company numbered drawings:** Documents issued, archived, and managed by engineering records personnel. Issued documents are identified using assigned "drawing numbers" and include traditional drawing formats and multipage letter sized written documents, such as O&MIs.

**Facility category:** A means to organize facilities into specific groups that share a common set of required critical documents.

**Farm tap regulator set:** A pressure regulator set, including both single and multiple stages of pressure regulation, which controls pressure to a service line.

## IMPLEMENTATION RESPONSIBILITIES

The Manager of Station Assessment, reporting to the Director of FIMP, oversees the implementation of this utility standard.

# Station Critical Documentation

## GOVERNING DOCUMENT

Utility Policy TD-01, “Gas Asset Management”

## COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

California Public Utilities Commission (CPUC) General Order 112-F, “State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission and Distribution Piping Systems.”

CPUC General Order 58A, “Standards for Gas Service in the State of California.”

## REFERENCE DOCUMENTS

**Developmental References:**

Utility Standard TD-4125S, “Maximum Allowable Operating Pressure Requirements”

**Supplemental References:**

Gas Design Standard H-10, “High-Pressure Regulator-Type Stations and Farm Tap Regulator Sets”

Gas Design Standard H-14, “Gas Regulator Stations – Spring-Loaded and Pilot-Operated Systems”

Gas Design Standard H-19, “Gas Regulator Stations – Control Valve Systems”

Utility Procedure TD-4125P-10, “Identifying Gas Transmission Assets”

Utility Procedure TD-4460P-10, “Gas Transmission Operating Maps and Operating Diagrams”

Utility Procedure TD-4551P-01, “Operating and Maintenance Instructions for Transmission Major Gas Control Stations”

Utility Standard TD-4461S, “Gas As-Built Packages”

Utility Standard TD-4540S, “Gas Pressure Regulation Maintenance Requirements for Self-Operated and Pilot-Operated Regulators”

## APPENDICES

Appendix A, “Required Documentation Matrix”

Appendix B, “Critical Document Interdependency Matrix”

## ATTACHMENTS

NA

# Station Critical Documentation

## DOCUMENT RECISION

This document supersedes Utility Standard TD-4551S, “Station Critical Documentation,” Rev. 1, issued 11/13/2013.

## DOCUMENT APPROVER

Terry G. White, Director, Facility Integrity Management & Technical Services

## DOCUMENT OWNER

Jennifer Lemus, Expert Gas Engineer, Standards and Procedures

## DOCUMENT CONTACT

Charles Lombardi, Senior FIMP Engineer, Station Assessment Program

Troy Rovella, Manager, Station Assessment Program

## REVISION NOTES

| Where? | What Changed? |
|---|---|
| Entire standard | The entire standard was rewritten and expanded. Major changes include the following:<br>• Removed strength testing reports, welding reports, fire pre-plans, and security plans.<br>• Added operating and maintenance instructions (O&MIs), piping and instrument diagrams (P&IDs), and equipment lists for Category B facilities.<br>• Added new categories for automated valves, District Regulator Stations, and large volume customer regulator (LVCR) sets.<br>• Lowered voltage criteria for electrical single line diagrams from 480 volts (V) AC to 50 V AC or DC.<br>• Standardized electrical diagrams, including the addition of electrical schematics for storage facilities, compressor stations, and Category A stations that have programmable logic controllers (PLCs).<br>• Added process to document approving additions or exceptions to the requirements. |

## Appendix A, Required Documentation Matrix



In Table 1, “Required Documentation Matrix,” an “X” identifies the indicated critical document type as being required for the indicated facility category.

**Table 1. Required Documentation Matrix**

| Facility Category / Critical Document Type | Storage Facility and Compressor Station | Category A Station | Category B Station | Automated Valve | LVCR Set | District Regulator Station |
|---|---|---|---|---|---|---|
| Operating Diagram | X | X | X | X | X | X |
| Operating and Maintenance Instructions (O&MI) | X | X | X | X | | |
| Operating Procedures | X[1] | | | | | |
| Control Philosophy | X | X[2] | | X[2,3] | | |
| Control System Architecture | X | X[2] | | X[2,3] | | |
| P&ID | X | X | X | X | | |
| Main Gas Piping Drawing | X | X | X | X | | |
| Equipment List | X | X | X | X | | |
| Line List | X | X | X | | | |
| Electrical Schematic | X | X[4] | | | | |
| Electrical Single Line Diagram | X | X[5] | X[5,6] | X[5] | | |
| Connection Diagram | X | X | X[6] | X | | |
| Hazardous Area Classification Drawing | X | X | X[6] | X | | |

1. Operating procedures are not required for unmanned compressor stations.
2. For stations that have a PLC, DCS, or controlling RTU.
3. Multiple automated valve locations may be covered by a common control philosophy and/or common control system architecture.
4. For stations that have a PLC.
5. For stations where voltage is present at 50 V or above (AC or DC).
6. For stations where electrical equipment is present.

## Appendix B, Critical Document Interdependency Matrix

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**Table 2. Critical Document Interdependency Matrix**

| | Operating Diagram | O&MI | Operating Procedures | Control Philosophy | Control System Architecture | P&ID | Main Gas Piping Drawings | Equipment List | Line List | Electrical Schematic | Electrical Single Line Diagram | Connection Diagram | Hazardous Area Classification |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Operating Diagram | | X | X | | | X | X | | | | | | |
| O&MI | X | | X | X | X | X | X | X | | | | | |
| Operating Procedures | X | X | | X | | X | | X | | | | | |
| Control Philosophy | | X | X | | X | X | | X | | | | | |
| Control System Architecture | | X | | X | | X | | X | | X | | X | |
| P&ID | X | X | X | X | X | | X | X | X | X | | X | |
| Main Gas Piping Drawing | X | X | | | | X | | X | X | | | | X |
| Equipment List | | X | X | X | X | X | X | | | X | | X | |
| Line List | | X | | | | X | X | | | | | | |
| Electrical Schematic | | | | | X | X | | X | | | X | X | X |
| Electrical Single Line Diagram | | | | | | | | | | X | | X | X |
| Connection Diagram | | | | | X | X | | X | | X | X | | X |
| Hazardous Area Classification | | | | | | | X | | | X | X | X | |