Pacific Gas and Electric Company®

2024 GAS SAFETY PLAN

March 15, 2024

Dear Reader,

PG&E has a fundamental responsibility to design, build, maintain, and operate our gas systems to keep customers and communities safe. The 2024 Gas Safety Plan ("Plan")[1] provides a high-level overview of the work we accomplished in 2023 and strives to present important Gas functional area information in a manner that is accessible and clear to a broad audience.

PG&E's 2024 Gas Safety Plan includes aspects showing how Gas has deployed PG&E's Clear Sky Playbook. The Playbook includes the Lean Five Plays which are visual management, operating reviews, problem solving, standard work, and waste elimination. First, in the PG&E Safety Excellence Management System section, the 2024 Plan describes how PG&E is transitioning from the Gas Safety Excellence framework to the PG&E Safety Excellence Management System (PSEMS). PSEMS is an integrated safety management system based on national and international industry standards. PG&E utilizes PSEMS to drive operational excellence, safety, and reliability performance across the company. Next, in the Coworker Engagement section, the Plan notes PG&E completed its first 12 Breakthrough Workshops. PG&E's Breakthrough Thinking is aimed to empower leaders and their teams to shift their mindset in order to achieve extraordinary outcomes. Last, PG&E deployed 15 Model Yards in both Gas and Electric Distribution Operations. The Model Yards accomplishments included training and coaching of the Lean Five Plays to frontline workers, implementing problem solving boards, and conducting 5S events in the Service Centers.

The Plan also includes updates on items discussed in previous Gas Safety Plans, including the following: First, in the Key Gas Improvement figure, Figure 1, PG&E achieved a response rate of 99.7% in handling gas odor calls in under 60 minutes. Second, in the Public Safety section, the Plan highlights PG&E's completion of NTSB Recommendation P-10-4 regarding establishing Maximum Allowable Operating Pressure (MAOP) on pipeline segments in all Class 3 and 4 locations, as well as High-Consequence Area (HCA) locations in Classes 1 and 2. Third, with a focus on the importance of the 10 Keys to Life, the Workforce Safety section notes reduction in Days Away, Restricted, or Transferred (DART) cases, a reduction in OSHA recordable incidents, and a reduction in Serious Incidents and Fatality – Potentials (SIF-Ps). Last, in the Transmission Pipe section, the Plan communicates the CPUC's approval of PG&E's gas transmission definition proposal. This proposal was submitted to incorporate key defined terms published in the PHMSA Mega Rule. The implementation of the transmission definition change will continue in 2024.

While we have made progress in key safety areas, we realize there is more to do to demonstrate our commitment and progress towards our True North Strategy. PG&E remains focused and dedicated to ensuring everyone and everything is always safe.

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[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 6,400 miles of transmission pipelines, over 44,000 miles of gas distribution pipelines, approximately 4.7 million customer meters, over 4,400 transmission and distribution (T&D) regulator stations and regulator sets, nine compressor stations, and three gas storage facilities. 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 provide reliable service and to keep everyone and everything always safe.

PG&E's Gas Safety Plan (Plan) provides a view into the safety activities PG&E pursues every day and highlights the specific gas safety work in 2023. PG&E annually reviews and updates its Plan in accordance with General Order (GO) 112-F Section 123.2(k) and Public Utilities Code (Pub. Util. Code) Sections 961 and 963.[1] Figure 1 below provides a summary of PG&E's performance in key areas.

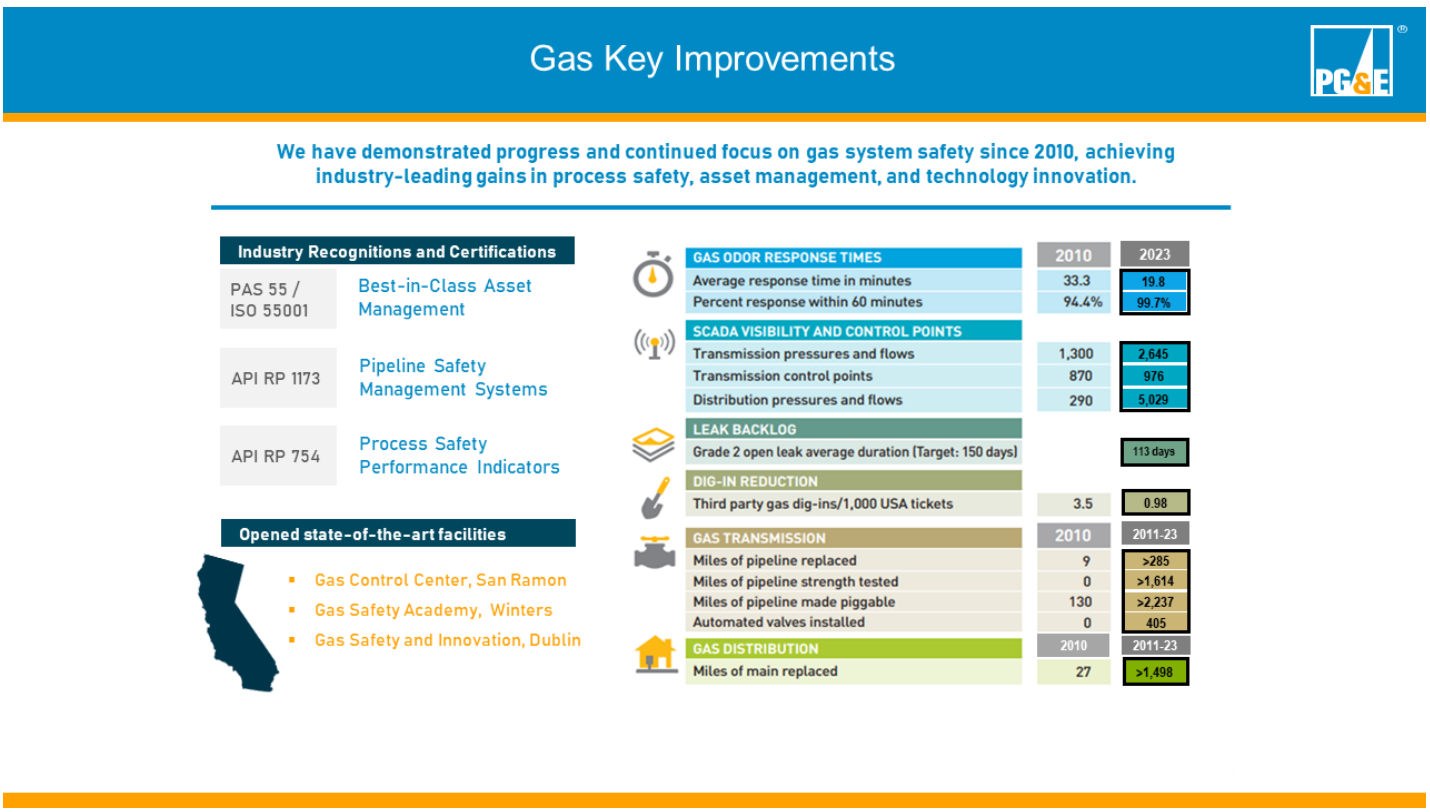


Figure 1 – Gas Key Improvements

1. STRUCTURE OF THE GAS SAFETY PLAN

The 2024 Plan reports the details associated with the work performed in 2023 to keep everyone and everything always safe. In alignment with California's regulatory framework,[2] 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.

- **True North Strategy:** This section calls attention to PG&E's True North Strategy. The True North Strategy is a living strategy that will be reflected throughout every coworker's day-to-day work and integrated into our enterprise planning processes over time. PG&E's True North Strategy sets the tone for the Company to focus on people, the planet, and prosperity.
- **PG&E Safety Excellence Management System (PSEMS):** Gas transitioned to PSEMS in the fourth quarter of 2023. PSEMS is PG&E-wide and builds on the Gas Safety Excellence Management System (GSEMS) framework established in 2012 to scale the safety management system across PG&E. Similar to GSEMS, PSEMS is an integrated safety management system, based on national and international industry standards. It provides the framework and structure to drive operational excellence and safety and reliability performance across PG&E. As PG&E transitions to PSEMS, Gas will continue to maintain certification to the requirements specified by industry and international standards for asset management, pipeline safety management and process safety performance indicators. Certification of conformance to the standards is assured through independent third-party audits.
- **Safety Culture:** This section highlights how PG&E is working to improve workforce safety through building a culture focused on the hearts and minds of our employees and building a deeper partnership between Gas leadership, Grassroots Safety Teams, and the Labor Unions.
- **Process Safety:** This section focuses on PG&E's efforts to prevent low frequency, high consequence incidents, and mitigating the consequences from these incidents.
- **Asset Management:** This section expresses how PG&E utilizes the Asset Management System and concepts of the International Organization for Standardization (ISO) 55001: 2014 standard for asset management systems. ISO 55001 specifies the requirements for the establishment, implementation, maintenance, and improvement of an asset management system for our gas assets. Concepts include knowing the condition of the assets, understanding the risks to those assets, implementing asset risk reduction strategies, maintaining asset condition and performance,

and balancing asset cost, risk, and performance in pursuit of the asset management strategic objectives.

- **Workforce and Compliance Framework:** This section reviews how PG&E qualifies, trains, and engages the workforce to mitigate risk by working on assets safely and performing work correctly.
- **Continuous Improvement (CI):** This section presents PG&E's efforts to work cross-functionally to continuously improve processes and procedures.

2. PG&E's True North Strategy

PG&E's True North Strategy represents where the Company is headed and how we will do it. It is PG&E's 10-year enterprise strategy that sets a clear vision of what it means to achieve our Purpose: Delivering for Our Hometowns, Serving Our Planet, and Leading with Love. PG&E's True North Strategy is a living strategy that will be reflected throughout every coworker's day-to-day work and integrated into our enterprise planning processes over time. Gas follows the Company's Business Plan Deployment (BPD) model to set annual goals and initiatives. This process incorporates the Company's True North Strategy to create functional area "Plans on a Page" that outline the strategic goals and initiatives for the year. The Gas functional area's "Plans on a Page" include both operational and engineering activities that align with the Company's focus areas: Safety, Quality, Delivery, Cost, and Morale, and the plans drive action throughout the business. Related goals and metrics cascade down through each functional area to provide all coworkers a line of sight to how their daily activities support PG&E's True North Strategy.

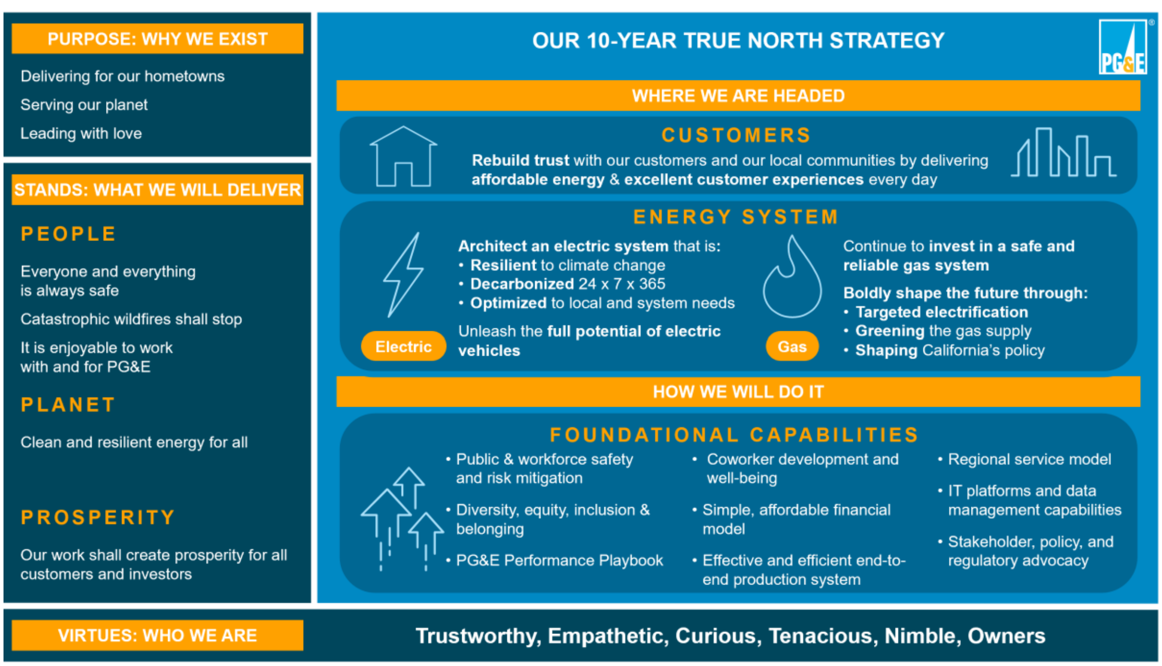


Figure 2 – PG&E's True North Strategy

3. PG&E SAFETY EXCELLENCE MANAGEMENT SYSTEM

Gas Safety Excellence is demonstrated by our True North Strategy to ensure everyone and everything is always safe. The journey to implement the GSEMS began in 2012 with the establishment of the Gas Safety Excellence framework. Supported by the pillars of Asset Management, Safety Culture, and Process Safety, the framework enabled Gas to establish processes and controls to systematically reduce risk and improve safety. It also required periodic leadership review of the safety management system to assure continued effectiveness and maturity.

Figure 3 – PG&E Safety Excellence Management System Elements

The successful implementation of GSEMS served as a model for the development of a PG&E-wide safety excellence management system in 2022. In 2023, the PSEMS manual was published. PSEMS integrates the requirements of international and industry standards for asset management, pipeline safety management and process safety into 13 elements. In addition to these three foundational standards, PSEMS also integrates key requirements from the ISO 45001 standard for occupational health and safety management systems. GSEMS will continue to the management system in Gas as deployment of PSEMS across the organization matures.

SAFETY MANAGEMENT SYSTEM CERTIFICATION

Certification of the GSEMS for compliance with best-in-class industry standards by an independent third-party auditor began in 2014. In 2023, PG&E's Gas functional area continued to maintain certification to the requirements of the following industry standards based on the results of surveillance audits by an independent third-party auditor:

- Publicly Available Specification (PAS) 55/ISO 55001 Asset Management System Requirements for Asset Management;
- American Petroleum Institute (API) Recommended Practice (RP) 1173 Pipeline Safety Management System for Safety Culture; and
- API RP 754 Process Safety Performance Indicators.

In 2018, Gas published the GSEMS manual which integrated the requirements of the three standards into one management system consisting of 16 elements to improve assessment of system maturity and effectiveness.

GSEMS elements establish requirements to address risks inherent to Gas and provide a model to systematically manage governance, policies, processes, and procedures. It also requires continual reviews to assure the system is working as intended.

In 2019, PG&E began to conduct biennial assessments of system maturity. These internal assessments have identified over 150 opportunities to improve system maturity. Figure 4 shows the results of the 2019, and 2021 and 2023 biennial assessments by system element. Examples of improvements resulting from maturity assessments include improved resource directories for emergency response and review of controls to improve occupational health and safety. The next maturity assessment is scheduled for the fourth quarter of 2025.

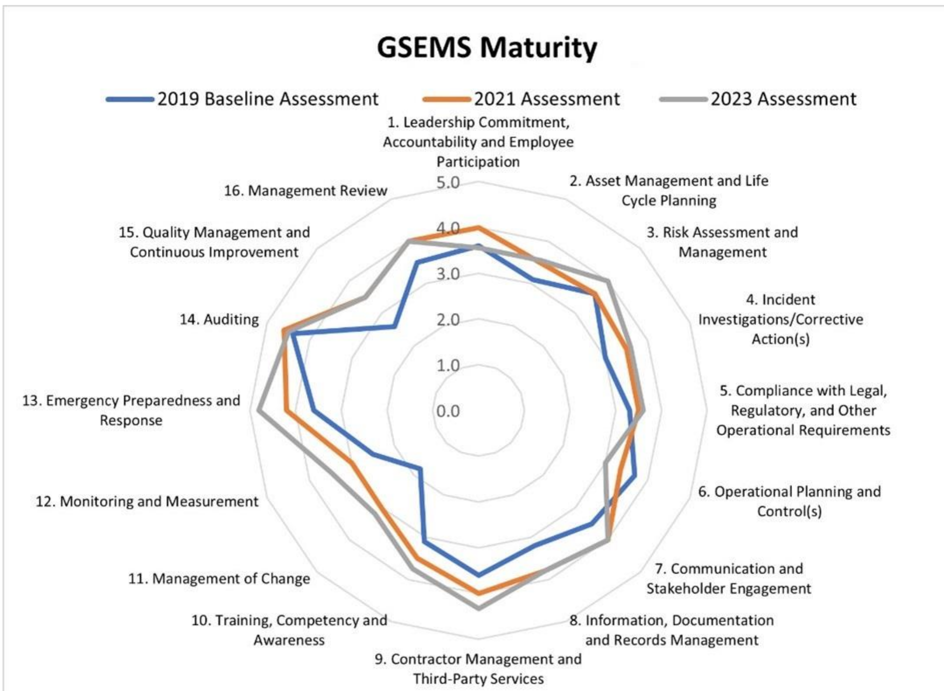


Figure 4 – Maturity Assessment Chart 2019, 2021 & 2023

4. Public Safety

As mentioned in the Introduction and shown in Figure 1, PG&E continues to make progress and improvements to support the safe operation of the gas system. Areas of continued focus to improve public safety are: In-Line Inspections, Third Party Dig-ins, Gas Emergency Response, and Strength Testing.

- **In-Line Inspections:** In 2023, PG&E increased piggability from 49 percent to roughly 51 percent of the approximately 6,400 miles of the Gas Transmission system.
- **Third-Party Dig-Ins:** In 2023, PG&E experienced 0.98 third-party dig-ins per 1,000 Underground Service Alert (USA) tickets, meeting the 2023 target of 0.98 third-party dig-ins per 1,000 tickets.
- **Gas Emergency Response**: In 2023, PG&E's average response time for immediate response gas odor or gas leak calls was 19.8 minutes, exceeding the target of 19.9 minutes.
- **Strength Test**: In 2023, PG&E completed strength-testing, or verified strength-test records, for our pipelines to complete all the National Transportation Safety Board (NTSB) requirements from Safety Recommendation P-10-4.

5. Workforce Safety

PG&E's goal is to continually reduce risk to keep our customers, our communities, and our workforce (employees and contractors) safe. Our focus is to continue building an organization in which we have designed every work activity to facilitate safe performance, every member of our workforce knows and practices safe behaviors, and every individual is encouraged to speak up if they see unsafe or risk behavior and has confidence that all concerns and ideas will be heard and follow up action will be taken.

PG&E aspires to eliminate workplace fatalities and reduce the number of serious safety incidents. PG&E established Days Away, Restricted or Transferred (DART) targets for 2023 to achieve a reduction from 2022. In 2023, Gas had 63 DART cases at a rate of 1.31 which is a reduction of 6 cases and a rate reduction of 0.15, or 10.3 percent from 2022. The top three DART injuries were Sprain/Strain, Musculoskeletal, and cut/laceration related. Gas utilized problem solving sessions throughout the year to target containment and countermeasures in reducing the top incident drivers.

Gas employees were involved in 30 Lost Time Injuries in 2023, which was equal to 2022. In 2023, the California Occupational Safety and Health Administration (OSHA) recordable rate decreased by approximately two percent from 2.78 percent in 2022 to 2.73 percent. This is a result of early intervention at the first sign of discomfort, PG&E's 24 hour, seven days a week Nurse Care Line (NCL), early reporting, and Industrial Athlete (IA) utilization. In 2023, 90.7 percent of employees who called the NCL reported discomfort or an injury within 24 hours, which was a 2.26 percent decrease from 2022. Based on the data, PG&E believes that encouraging employees to speak to healthcare professionals about injuries or illnesses within 24 hours contributes to reduced severity and recovery time of injuries or illnesses. Through consistent application of timely reporting and preventative efforts, the serious Lost Time Injuries have begun to follow the OSHA recordable curve and shows improvement.

In 2023, Gas had seven safety incidents with Serious Injury and Fatality Potential (SIF-P). All seven SIF-Ps incidents were work-related, and five of the incidents were related to motor vehicle safety. To reduce the number of SIF-Ps , PG&E's Gas Safety Improvement Strategy reinforced Human Performance standards (examples include, but are not limited to, three-way communication, job hazard analysis, and step-by-step place keeping for critical operational tasks), emphasizing the importance of the 10 Keys to Life (Figure 5 below), and building the capacity to fail safe into our high-risk work activities. Gas Operations rolled out human performance within Gas Construction targeting organizational leaders and subsequently field employees. This roll out engaged 1,400 Gas employees in over 40 training sessions. This human performance training was conducted throughout the service territory. PG&E continued its adoption in 2023 of Edison Electric International's (EEI) Safety Classification Learning Model (SCL) to classify its serious injury or fatality (SIF) incidents. The EEI SCL model classifies incidents into categories: High-Energy SIF (HSIF), Low-Energy SIF (LSIF), Potential SIF (PSIF), Capacity, Exposure, Success & Low Severity. Adopting the EEI SCL Model has improved the SIF program by bringing a consistent and objective approach to reviewing, classifying, and deploying corrective actions to prevent reccurence of SIF incidents across the company and industry.

Once an incident is determined to meet SIF criteria, a cause evaluation team is assembled to investigate the facts of the incident, and identify the causal and contributing factors. The team also develops comprehensive corrective actions to minimize and/or prevent reoccurence. Upon completion of the internal investigation, a written report is presented to the Corrective Action Review Board to evaluate and accept the corrective actions. The Corrective Action Review Board is comprised of Gas Leaders, Gas CAP Leaders, and Enterprise Health and Safety (EH&S) Leaders. Once approved, the corrective actions are entered into CAP and tracked and monitored to completion. Following closure of all corrective actions, an effectiveness review is conducted to determine if the actions taken were effective in preventing or mitigating the original outcome.

PG&E continued additional evaluation measures in 2023, such as Timely Corrective Action Completion and Quality of Corrective Actions, to focus on both the quality and timely closure of corrective actions from SIF investigations. In 2023, Gas completed 100 percent of the corrective actions related to SIF events in a timely manner.

Another area of focus continues to be Motor Vehicle Safety. In 2023, there were nine Serious Preventable Motor Vehicle Incidents (SPMVI). In 2017, the Company installed an in-cab coaching technology in over 2,600 gas vehicles and developed a metric to score employees' driving behaviors. The technology alerts drivers when they accelerate too fast or brake too hard. These are both leading indicators for incidents that have the potential to cause extensive damage or a SPMVI. PG&E tracks a Safe Driving Rate by calculating the number of Hard Braking events and Hard Accelerating events per 1,000 miles driven. In 2023, Gas finished with a Safe Driving Rate of 3.3, a reduction from the 3.4 recorded Safe Driving Rate in 2022. The company continues to improve its motor vehicle safety program, conduct more driver observations, evaluate backing sensor technology, enhance driver safety training, and promote awareness campaigns. PG&E will strive to continue to reduce OSHA recordable injuries, the DART rate, and motor vehicle incidents.

Figure 5 – 10 Keys to Life

6. 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 are those who submit CAP items identifying and addressing issues that result in significant improvements to safety, reliability, compliance, cost reduction, or process. 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 Workforce Safety Strategy. As a token of appreciation, the employees who nominate them are also eligible to receive rewards and recognition.
- **Process Safety Champion** – This champion recognition distinguishes teams and individuals who have gone above and beyond in applying Process Safety principles to their work. Examples of going above and beyond include having a questioning attitude, taking time to evaluate hazards prior to starting tasks, and submitting material issues into the Corrective Action Program (CAP) system.

7. Natural Gas Leak Abatement Compliance Plan

On January 22, 2015, the California Public Utilities Commission (CPUC or Commission) issued the Order Instituting Rulemaking (OIR) R. 15-01-008 to implement the provisions of Senate Bill (SB) 1371 (Statutes 2014, Chapter 525). SB 1371 requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities consistent with Public Utilities Code § 961(d), § 192.703(c) of Subpart M of Title 49 of the Code of Federal Regulations (CFR), the Commission's GO 112-F, and the state's goal of reducing GHG emissions. In the June 15, 2017, Decision D.17-06-015, the Commission adopted 26 Best Practices related to natural gas leak abatement (phase one). PG&E's Natural Gas Leak Abatement Program includes annual methane emission tracking and reporting as well as the submission of a biennial best practice compliance plan.[45]

PG&E has made strides in reducing the methane emissions on its systems through the execution of its first three Compliance Plans. The main measures that have been implemented are listed below.

Under the 2018-2019 Compliance Plan:

- Acceleration of detection and repair of larger leaks of its distribution system (Super Emitter Program);
- Acceleration of distribution leak survey from 5 to 3 years;

- Application of cross compression and drafting practices on scheduled backbone transmission pipeline projects;
- Replacement of more than 100 high bleed controllers at Compressor Stations and Storage Facilities; and
- Introduction of quarterly leak surveys at Compressor Stations and Storage Facilities.

Under the 2020-2021 Compliance Plan:

- Implementation of meter set leak bubble classification framework and repair prioritization;
- Addition of project bundling as an abatement technique to reduce emissions associated with project blowdowns;
- Extension of cross compression activities to local transmission projects; and
- Further reduction of the pipeline pressure during cross-compression on scheduled backbone transmission pipeline projects.

Under the 2022-2023 Compliance Plan:

- Decrease of the Super Emitter threshold from 10 to 7 standard cubic feet per hour (scfh);
- Completion of Super Emitter surveys earlier in the year;
- Leverage of Super Emitter leak survey drives for Distribution Integrity Management Program (DIMP) Vintage pipeline surveys, which improved cost-effectiveness of this annual survey;
- Replacement of 10 high bleed pneumatic devices at Transmission Meter and Regulation (M&R) Stations; and
- Extended blowdown reduction strategies to compressor station and storage facilities into 2023.

The 2024 Leak Abatement Compliance Plan (2024 Compliance Plan) is the fourth biennial Leak Abatement Compliance Plan prepared in accordance with the Commission's decision and covers the years 2024-2025.

II. Safety Culture

PG&E's commitment to strengthen our safety culture and performance is reinforced by our stand that "Everyone and Everything is Always Safe" (see Figure 6). Gas Safety and Leadership worked to improve workforce safety through building a culture focused on the hearts and minds of our employees and cultivating a deeper partnership between Gas leadership, Grassroots Safety Teams, and the Labor Unions. The goals of the partnership are to prevent and reduce employee injuries, promote healing, and return to work, and ensure quality and appropriate medical care for our employees. In 2023, with leadership support, Gas continued its focus on these goals.

In 2023, Gas rolled out Human Performance within the Gas Construction Organization and other support organizations. Human Performance was widely deployed and cascaded throughout the organization from Directors to field employees. The Human Performance training sessions were completed throughout the service territory and resulted in over 1,400 employees being trained. Diablo Canyon Power Plant is leading the way in Human Performance, and Gas will continue to expand Human Performance in 2024.

Figure 6 – PG&E Stands

Also, in late 2021, a consultant was engaged to develop and implement a new element to Gas' safety approach through the creation of Safety Culture Guidance Teams (also referred to as Village Safety Culture Teams). These nine teams are composed of bargaining unit/management coworkers carefully selected for being safety leaders who can positively influence their teams locally. Each Safety Culture Guidance team has their own mission statement and culture actions to improve the safety culture of its village. To sustain the safety culture journey, the consultant has continued to provide virtual consultation to each village to ensure focus on culture work and culture-based project development. The culture villages continue to be a key element in the safety culture journey in Gas Operations.

In addition, a group of Gas coworkers received training to become Safety Culture Tools Facilitators to deliver key tools to employees to support Gas-wide culture topics. The training provided was for two specific culture-based Tools: Culture Iceberg and Cycle of Mistrust.

In parallel, PG&E continued with its Gas Safety Council and Gas Grassroots Safety teams in 2023. More information on the Gas Safety Council can be found in the Gas Safety Council section below (Section II.2.A). More information on the Grassroots Safety Teams can be found in the Grassroots Safety Teams section below (Section II.2.b).

Furthermore, Gas continued to champion the Industrial Athlete Specialist (IAS) Team for frontline employees and provide leaders with the necessary injury data to aid in implementation of injury prevention measures. Regional support consists of three to six IASs to support the program. This program provides education and early symptom intervention to help our field coworkers avoid injuries and stay safe, healthy, and well at work. IASs are professionals trained in sports medicine. They are assigned to regions throughout the enterprise and visit sites within their region regularly. They are also available for "on call" services.

IAS Services include:

- Body mechanics coaching to prevent injuries on the job;
- Individual and group education on topics such as performing task-specific stretches and preventing sprains and strains; and
- Support for discomfort, both work-related and non-work related.

In 2023, 38 percent of the Gas eligible physical workforce participated in 1-1 services with an IAS. 97.3 percent of coworkers with a resolved IAS discomfort case did not have a new MSD-related worker's compensation claim within six months after case closure.

Virtual Ergonomic Assessments for Remote Workstations. In alignment with the enterprise requirement for office-based employees to complete preventative virtual ergonomic evaluations, 732 ergonomic evaluations were requested in 2023. Of the 732 evaluations requested, 700 were completed, reflecting a 95.6 percent completion rate. In 2024, office ergonomic goals will focus on issue resolution with a company-wide goal of <=1 open issue. The goal is not zero, as discomfort is counted as one open issue. Employees with work-related discomfort should contact the Nurse Care Line (NCL) and request an ergo evaluation for discomfort resolution. Unresolved items on the issue resolution dashboard correlated with over 90% of office ergo recordable injuries in 2022 and 2023. In accordance with PG&E's Office Ergonomics Standard (SAFE-1053S), open issue resolution items are to be addressed within 60 days after completing office ergonomics training and self-assessment. Gas Leadership, in partnership with Grassroots Safety Teams and Labor Unions, will continue to reinforce PG&E's commitment to safety and encourage its employees to work safely. Gas will continue to use Industrial Ergonomics to minimize hazards related to work equipment, environment, tools, and processes through prioritization of frequency of activity by work type, looking for quick wins by changing out tools, and sharing immediate lessons learned with others to reduce hazards.

As an organization, PG&E's ongoing focus is to reduce unsafe behaviors by connecting with those that do the work, to build/improve our Safety Culture by focusing on the hearts and minds of our employees and to continue to build a deeper partnership between Gas and Labor Unions to drive safety.

1. Coworker Engagement

PG&E continues to support various coworker engagement activities and initiatives, all at various stages of implementation, which all support a healthy safety culture. For example, in 2021 and 2022, the Executive Officer Team introduced the Lean Operating System (formerly Lean Management in Gas), the Joy at Work survey (a way to measure coworker morale), and Breakthrough Thinking (process to foster extraordinary outcomes) as company-wide activities. In 2023, Operations deployed the Co-worker Town Hall Meetings,[3] which aim to equip frontline leaders with the tools necessary to support their teams. These activities are in addition to Gas-specific initiatives in flight such as Safety Leadership Development, Leader in the Field and the new Role of the Supervisor.

Lean Operating System. Gas deployed Lean Management in 2017 and continues to support and reinforce the importance of Lean thinking throughout the organization. The Executive Officer Team expanded Lean implementation to all PG&E organizations starting in 2021 by introducing the Lean Operating System as PG&E's way of working as we build a better, safer PG&E for our customers, coworkers, and our hometowns. The Lean Operating system is designed to drive more effective decision-making and reduce the human struggle that can be in the day-to-day work and that our customers sometimes face in working with us. The Company's Clear Sky Playbook is the standard for implementing the Lean Operating System, which lays out the four basic plays: visual management, operating reviews, problem solving, and standard work.

Lean implementation also encourages leaders to spend more time directly engaging with their team members. Leaders regularly visit locations where the work is occurring to meet coworkers, hear their thoughts on what is working well and where improvements are needed, and to observe the work being performed to identify opportunities for continuous improvement.

In 2023, Gas Operations and Gas Engineering held operating reviews and established command centers. The operating reviews include a look at the daily, weekly, and monthly key performance indicators to ensure that Gas is on track to meet its targets. There are both functional area operating reviews and combined/cross functional operating reviews. The command centers focus on Expense and Capital work, Undergrounding, and workforce Safety.

Safety Leadership Development. Beginning in 2017, the *Leading Forward: Safety Leadership* program was delivered to all operational leaders. The program originally included three workshops over three days: Shaping a Safety Culture; Identifying and Controlling Exposure; and You Are Not Alone. The program has been condensed into two days but covers the same topics. In 2023, the content was updated to include information about PG&E's Safety Excellence Management System and Institute of Nuclear Power Operations 10-Traits of a Healthy Safety Culture. The training was delivered to gas supervisors and crew leads with the addition of several key roles identified (who may also temporarily lead crews). A total of 245 Gas coworkers (31 Crew Leads, 96 Supervisors and Superintendents, and 118 others) completed the program in 2023.

Leader in the Field. Leader in the Field was deployed in 2020, which focused on the supervisors and managers being in the field with their coworkers to assist in removing barriers and resolving safety concerns. Across Gas, supervisors' time in the field averaged approximately 56 percent throughout 2023, compared to 50 percent in 2022. This means over half of their working hours were spent in the field with frontline workers. For PG&E Gas Operation Managers, time in the field averaged approximately 31 percent throughout 2023, compared to 23 percent in 2022.

Role of the Supervisor. This strategy aims to elevate and redesign the role of the supervisor, encompassing brand reputation and meaningful experiences where supervision is an attractive, important, and supported position throughout the company, and coworkers aspire towards the role. In 2023, PG&E continued its 2022 engagement efforts and enhanced supervisor engagement with the expansion of Supervisor Central Program through First Line Network calls, Office Hours calls and newsletter; completed Day in the Life/Time in Motion study which included observations on over five percent of supervisors across the enterprise in support of creating standard work; evaluated and developed standard work to align supervisor onboarding across the enterprise; and launched *Leading at PG&E* leadership training that includes six courses focused on elevating leaders across the enterprise in leading co-workers, safety culture, business acumen, breakthrough thinking and lean principles.

Joy at Work. One of PG&E's stands is that it is enjoyable to work with and for PG&E. At the heart of making this stand a reality is creating an environment where all of our coworkers know Joy at Work. We believe our entire PG&E family has and should know Joy at Work in how we live and accomplish our Purpose—delivering for our hometowns, serving our planet, and leading with love. We believe the key to our coworkers knowing Joy at Work is to be known, loved, and proud to work at PG&E.

To develop a deeper understanding of our coworkers' experiences, PG&E introduced a new survey to measure Joy at Work in 2022. The survey measures whether coworkers enjoy working for PG&E and whether coworkers feel known, loved, and proud to work for PG&E.

In 2022, we captured feedback from 14,478 coworkers and achieved an overall Joy score of 60 percent company-wide with similar results for Gas. We analyzed coworker comments and identified drivers of joy at PG&E. The results of the survey provided insights to leaders and their teams on actions to take to improve Joy at Work such as team building activities, volunteering opportunities, in-person meetings, standardized work, and communications, among other activities. The Joy survey was deployed again in late 2023 and the company saw an overall improvement in the Joy score at 67 percent, which is similar to Gas combined scores. Actions will be taken in 2024 to further improve Joy at Work amongst our coworkers.

Breakthrough Thinking. PG&E aims to become a "breakthrough organization" that delivers for hometowns, serves the planet, and leads with love. A breakthrough organization occurs when leaders and teams shift their mindset to achieve extraordinary outcomes. The Company's Breakthrough Program has four key building blocks to help leaders and teams learn how to utilize breakthrough thinking to achieve breakthrough outcomes.

The first building block is the Breakthrough Intensive, an immersive leadership team experience that enables leaders to think and act in new ways by gaining fundamental tools to uncover and change mindsets. This program helps teams emerge grounded in their ability to produce results that previously seemed impossible.

The second building block is the Performance Diagnostic, which provides leaders with a data-driven approach to measure and change a company's current environment. The Performance Diagnostic is a simple and scalable survey that uncovers intangible team dynamics that impact business performance. When used together with the Breakthrough Intensive, the Performance Diagnostic provides a powerful platform for essential performance conversations during times of crisis.

The third building block is Breakthrough Specialists—individuals who play a critical role in cultivating the Breakthrough Performance Environment by delivering Performance Diagnostic debriefs in partnership with leaders and their teams. They are also equipped to lead the Breakthrough Performance Environment day-to-day, in service of impacting breakthrough performance across the business.

The final building block is Breakthrough Debriefs, which are a key tool for helping leaders and teams transform themselves by transforming data from the Performance Diagnostics into valuable information. Breakthrough Debriefs help leaders, teams, and specialists review the results and connect the Five Factors and their business impacts to the teams' current performances. Specialists lead fluid conversations and explain the connections between the factors, helping team members understand how the factors and how changes in scores and distribution will impact their future performance.

PG&E hosted 12 Breakthrough Workshops in 2023 to help empower leaders to create a breakthrough performance environment where breakthroughs are the norm. In 2024, the Breakthrough Performance Program will build upon this progress by exposing an approximate additional 1,400 people leaders to Breakthrough via 13 additional sessions and certifying an additional 51 Breakthrough Specialists.

Coworker Town Halls. In 2023, PG&E held 12 Coworker Town Halls across our 5 Regions with the purpose to engage with frontline leaders on the True North Strategy, Purpose, Virtues and Stands, Lean Operating System, and the PSEMS. The focus was to equip and empower leaders to be owners in these areas and provide them with the tools and information needed to successfully lead their teams.

Forty-five percent of the frontline and back-office leaders from Operations, Engineering Planning & Strategy, Customer, Information Technology, Shared Services, and Supply Chain attended one or more Coworker Town Halls.

For 2024, building on learnings from 2023, we will work toward being Owners together with a focus on PG&E's virtue of being Trustworthy. These town halls will be attended by supervisors, superintendents, senior managers, and managers from all functional areas, and will be renamed Leadership Town Halls (LTH) to encompass the identified attendees.

a) Corrective Action Program

The Corrective Action Program (CAP) is an integral part of our safety culture in Gas. PG&E's continued use and support of the CAP demonstrates to coworkers, contractors, regulators, and customers our unwavering commitment to delivering safe, reliable, affordable, and clean energy. The CAP process ensures that notifications are categorized, assessed for risk, and assigned to the appropriate owner to resolve issues and implement effective corrective actions to help prevent recurrence. Our goal is to move Gas from a reactive approach of solving issues to a proactive analysis that helps prevent issues before they result in an incident. 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.

The Gas CAP team is composed of CAP quality operations specialists and cause evaluators. The quality operations specialists handle the day-to-day management of CAP submissions, including assignments, coaching, and training, reviewing closed CAP issues, trending analysis, data requests, and metrics. The cause evaluators facilitate the end-to-end process of an investigation or cause evaluation (root, apparent, or common cause), including team training, interviews, analysis, report writing, and working with the functional leader for approvals. The cause evaluation team is also responsible for all SIF coworker and contractor Serious Injury or Fatality (SIF) investigations and works in conjunction with Enterprise Safety to ensure effective implementation of the process.

What Gets Reported into CAP

PG&E encourages employees to identify issues related to gas assets, processes, and overall safety of our employees, contractors, and the public for submission into CAP for resolution and tracking. There are a few matters that may fall outside the scope of CAP (e.g., Ethics and Compliance issues, facility requests); however, we do not discourage their entry, but instead transfer such CAP notifications to the most appropriate tool or program for follow up.

How the Gas CAP Process Works

Initiation: The initiator, who can be any PG&E employee or contractor, can submit any issue or process improvement idea into the CAP. Coworkers have several ways to submit an issue, such as through the CAP website, the mobile CAP App, the CAP helpline, paper form, SAP, or via email to the CAP help desk. Once the CAP is in submitted status in Gas, the Gas CAP team will process it for assignment. On average, Gas employees submit roughly 750 CAP issues each month.

Assignment and Resolution: The CAP process employs a standardized approach (Figure 7) to review and assign CAP Issues and Actions. This process is facilitated by the Gas CAP Review Team (CRT). The Gas CRT is composed of Subject Matter Experts (SME) from various Gas departments that meet regularly to review newly submitted CAP notifications. The CRT's function is to categorize each notification, assess it for risk (using the enterprise CAP risk matrix), and assign it to an issue owner. After the CRT meeting, the CAP team finalizes each issue and prepares them for release to the agreed upon issue owners.

Once the CAP is assigned to an issue owner, it is the issue owner's responsibility to review the notification, identify the causes underlying the issue, and address them appropriately by implementing any necessary corrective actions to mitigate risks and/or prevent recurrence (based on risk and evaluation level).

After a CAP notification has been submitted and released to an issue owner, initiators receive an e-mail detailing to whom their notification was assigned. They also receive an e-mail again when their notification is closed. This gives the initiator the opportunity to learn how the issue was resolved and to provide feedback on their satisfaction with the results.

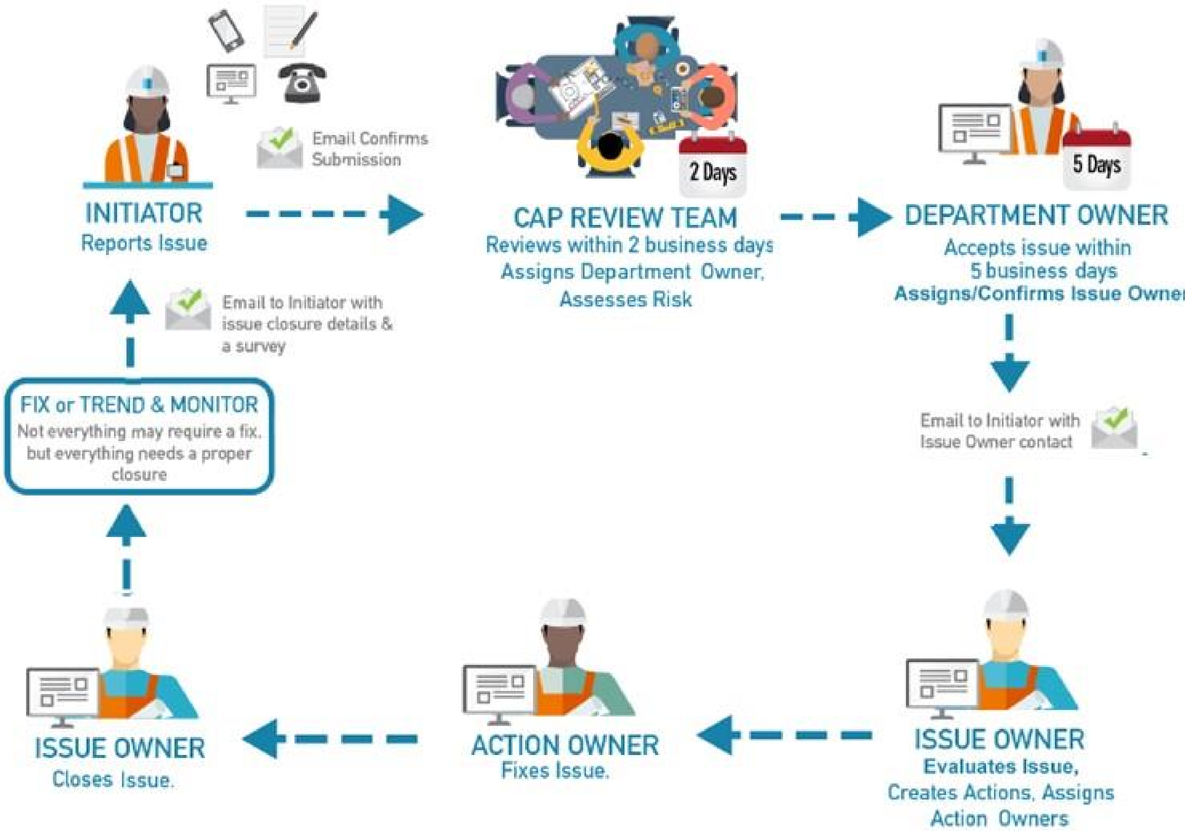


Figure 7 – CAP Process

How Notifications are Risk Ranked

Risk matrices are used to rate and compare risks of hazardous events by considering the likelihood and consequence of an event happening to increase visibility and to help with decision making on the risk reduction processes. Risk and safety are highly dependent on an individual's perception, meaning risk and safety mean different things to different people. Risk matrices are designed to minimize individual influence and normalize risks to be uniform regardless of who is risk ranking hazards. Risk matrices, especially when assessed qualitatively, provide only an estimated assessment of risk and are used to provide initial decision guidance and do not produce definitive risk assessments. Quantitative risk assessment methods are available when a better estimate of risk is required to better allocate resources. The CAP risk matrix is a qualitative risk assessment.

The initial risk ranking of a CAP notification is based on the information available and application of the following calculation to assist reviewers with combining known facts to identify the risk of the CAP notification:

<u>Probability of Event Occurrence x Severity of Consequence = CAP Notification Risk</u>

- **<u>Probability of Event Occurrence</u>**: The extent to which an incident, event, or condition has occurred or recurred (frequency).
- **<u>Severity of Consequence</u>**: The result of an incident, event, or condition by considering the degree[4] the public, employee(s), or property was in jeopardy of harm or loss (severity). This includes an assessment of the risk associated with safety, asset damage, reliability, financial impact, compliance, environment, and reputation.

The CAP notification risk level is used to determine the appropriate evaluation type that will be assigned and provides Gas with the ability to prioritize CAP notifications. Cause evaluations are necessary to identify the cause of an incident, issue, or error to prevent or minimize the probability of reoccurrence and to apply continuous improvement processes. There are four types of cause evaluations:

- **<u>Root Cause Evaluation (RCE)</u>:** An RCE is a formal and rigorous investigation that uses industry-accepted analysis methods to determine the root cause(s) of a problem. The RCE identifies required corrective actions that prevent or reduce the likelihood of a recurrence of the problem for the same or similar root cause(s).
- **<u>Apparent Cause Evaluation (ACE)</u>:** An ACE is an evaluation based on readily available information that provides reasonable assurance that the cause of a problem is determined and will be corrected. An ACE is conducted when management determines a formal but less rigorous cause evaluation is necessary.
- **<u>Common Cause Evaluation (CCE)</u>:** A CCE is an analysis method that can be used to identify common underlying elements among different, unique, but similar events or issues. The underlying elements may be anything from a common failure mechanism to a common cause that may or may not require further investigations. A CCE can be conducted only when the individual issues have been evaluated on their own merits (i.e., ACE or WGE report completed) and causes and corrective actions have been identified.
- **<u>Work Group Evaluation (WGE)</u>:** A WGE is a logical evaluation of an issue to identify reasonable corrective or preventive actions needed to resolve an issue. Resolution of the issue may be addressed by another process or a simple explanation of why something does or does not happen.

Figure 8 provides the Gas Event Classification Matrix (ECM), which was developed to provide formal guidance and consistency to determine the appropriate level of cause evaluation.

Gas Event Classification Matrix						
UNINTENDED OPERATIONAL EVENTS[1]						
Investigation Level *May be escalated or deescalated by Leadership as necessary*	PIPELINE HIT, RUPTURE, or EXPLOSION	PRESSURE EVENTS (Over and Under Pressure)	OTHER LOSS OF CONTAINMENT EVENTS	OTHER OPERATIONAL EVENTS	SAFETY	OTHER QUALITY/COMPLIANCE EVENTS
Significant Operational Events ***Root Cause Evaluation (RCE)***	• Transmission pipeline damage with loss of containment	• Overpressure event with loss of containment or overpressure event that impacts over 200 customers • Loss of service to over 2000 customers	• Explosion or fire due to loss of containment that impacts PG&E's or customer's property (i.e. house explosion)	• Loss of odorant (outside of regulatory limits) at customer lines • Loss of system wide visibility (SCADA) • Other events that significantly impact the safety, reliability, or integrity of the pipeline system	• SIF-Actual Events[2] • Serious injury or fatality to the public due to gas asset failure or operational change	• No new event types defined
Moderate Operational Events ***Apparent Cause Evaluation (ACE)***	• Transmission pipeline damage with no loss of containment • Distribution asset loss of containment resulting in fire	• Large overpressure event with NO loss of containment[3] • Unintentional loss of service to 200-2000 customers (excludes non-at-fault dig-ins) • Reasonable potential loss of service to over 2000 customers (i.e. unintended closure of valves, blockage in pipeline)	• Significant gas accumulation within explosive limit due to loss of containment without appropriate safeguards • Other loss of containment events (i.e. lube oil, pipeline liquids) with moderate impact	• Loss of odorant (outside of internal limits) at customer lines • Potential loss of system wide visibility (SCADA) • Over-odorization of gas resulting in an increase in customer odor calls • Loss of visibility to multiple mountain tops (SCADA) for 4 hrs or more • Other events that had the reasonable potential to significantly impact the safety, reliability, or integrity of the pipeline system	• SIF-Potential Events[2] • Potential for serious injury or fatality to the public due to gas asset failure or operational change	• Mandated self-reports • NOV and NOPV findings requiring ACE as determined by regulatory compliance
Minor Operational Events ***Work Group Evaluation (WGE)***	• At-fault dig-in on a distribution asset without fire or explosion	• Small overpressure event or near-hit overpressure event[3] • Loss of service to less than 200 customers (excludes non-at-fault dig-in)	• Loss of containment with low likelihood of fire or explosion	• Crossbore created during construction or maintenance activities	• Non-SIF injuries	• High Quality Assurance Findings • Self-reported non-conformances • NOV findings

[1] An unintended operational event is defined as an event resulting from work at/for PG&E involving gas assets that impacted or had the potential to impact the following: the safety of the public or our workforce (employees and contractors); the integrity of gas assets; the reliability of gas delivery; normal operations of the gas system; compliance with standards and regulations. *Does not include 3rd party at-fault events or natural disasters.
[2] All workforce serious injuries or fatalities actual and potentials are determined using process and definitions in SAFE-1100S. Serious injuries are life-threatening or life-altering injuries.
[3] Small and large overpressure events are defined by FIMP.

Figure 8 – Gas Event Classification Matrix

A cause evaluation can be related to a wide range of topics in Gas, such as asset failures, reliability (e.g., dig-ins, overpressure (OP) events), and workforce safety incidents (i.e., SIF incidents). A cause evaluation can be requested by an employee on any CAP notification; however, an RCE is generally assigned to incidents where the consequence severely impacts public or employee safety, or reliability, and warrants rigorous analysis.

All CAPs require a WGE, and in-depth WGEs are required for non-conformances and high-risk quality findings. Table 1 shows the total number of evaluations completed in 2023.

Table 1 – Gas Cause Evaluations Completed in 2023			
RCE	ACE	WGE	CCE
1	30	9,204	4

How CAP Success is Measured

In 2023, Gas' goal was to engage at least 33 percent of its workforce to use CAP to encourage employees' participation, and at year-end it had engaged approximately 24 percent. On average, Gas generates between 9,000 and 10,000 CAPs per year, one of the highest rates within PG&E.

To ensure accountability and transparency, leaders receive an Executive CAP Dashboard Report (Figure 9) each week that details how their organization is performing on their CAP items. Key performance indicators reported in 2023 include:

- Percent of Unique Initiators – This is the number of employee submissions divided by the total count of employees. The 2023 goal was greater than or equal to 33 percent of unique initiators.

- CAP Throughput – This number measures the volume of work being completed by the organization. The 2023 goal was 1.0, meaning that the volume of closed notifications equals the volume of submitted notifications.
- Average closure satisfaction (1-5 scale) is the sum of survey scores divided by the number of survey submissions. The 2023 goal was an average closure satisfaction greater than or equal to 3.5, where 5 is "very satisfied" and 1 is "did not meet expectations."
- Quality closure (percent) is the number of CAP notifications passing quality review divided by the number of CAP notifications reviewed. The 2023 goal for quality closure was greater than or equal to 92 percent.
- Average Age of Open High-Risk Notifications (days) – This is the number of days high-risk notifications are open divided by the number of open high-risk notifications. The 2023 goal for average age of open high-risk notifications was 300 days.
- Average Age of Open Medium-Risk Notifications (days) – This is the number of days medium-risk notifications are open divided by the number of open medium-risk notifications. The 2023 goal for average age of open medium-risk notifications was less than or equal to 230 days.

Figure 9 shows how Gas performed against the above-mentioned key performance indicators in 2023.

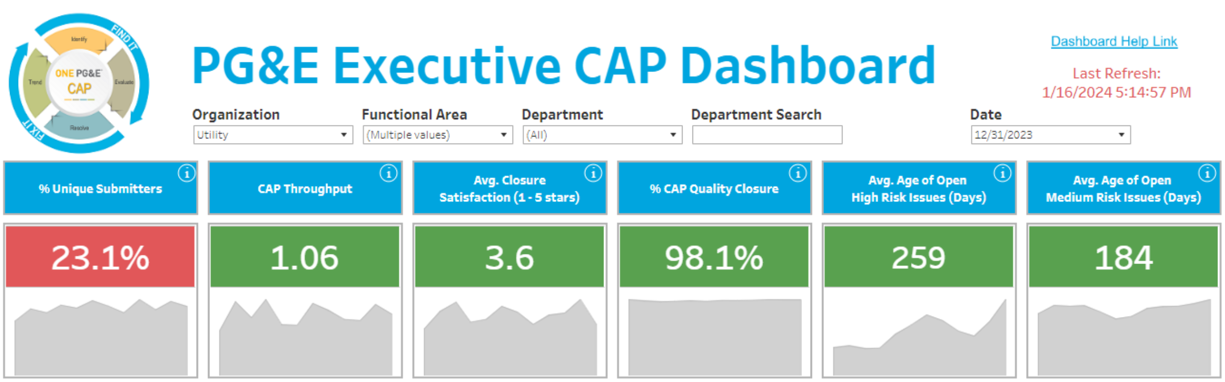


Figure 9 – CAP Metrics

Continuous Improvement and Speak Up Culture

The Gas CAP process continues to mature and serve an important role in Gas to identify and mitigate operational and safety issues and implement process improvements. The Gas CAP department also looks for ways to improve how it supports the business and continues to bring added value to operations.

Eagle Eye Program: The Eagle Eye Program was created to recognize employees who use the CAP to identify and address issues that result in significant improvements to safety, reliability, compliance, cost reduction, or process. The program was so successful in Gas that all of PG&E's functional areas adopted the Gas model when CAP was deployed companywide. In 2023, the CAP Department logged 69 Eagle Eye nominations, which included nominations for identifying and submitting “good catch” issues and for efforts in resolving those issues.

Trending: The CAP team improved its methodologies and capabilities within the trending program to track and analyze similar or repeat issues. As part of our efforts, the process evolved from capturing cognitive trends during CRT meetings by standing up a new structured potential trend process. The potential trend process complements the cognitive trend process by creating a formalized systematic statistical approach. The CAP team performs monthly Potential Trend (PT) analysis at Director/Manager level using SAP exported data to “bucket” data into categories utilizing issue type, subtype, department, and risk level. The data is then analyzed based on issue count within each bucket. If a PT is identified, then a new CAP is created as a stand-alone CAP for further analysis to determine whether the trend is classified as adverse. Using these processes, the team is able to capture emerging trends that can be further analyzed and communicated to key stakeholders within Gas. These trends are categorized by issue type, subtype, functional team, and risk level to further identify common issues and trends.

Through this approach, the CAP team discovered 4 potential trends in 2023 and provided analysis and recommendations to the respective functional team in Gas.

Quality Closure Review (QCR): QCR is a process in which the CAP team reviews closed notifications to determine if the responses meet the minimum quality closure requirements. To meet QCR, the notification must meet the following: (1) Well defined issue; (2) Not closed to a promise; (3) Sufficient documentation; (4) Justification for no action taken; and (5) Extent of Condition performed (if required). Gas CAP reviews 100 percent of all closed notifications on a weekly basis. If the CAP team determines that a notification did not meet the minimum requirements of QCR, then a team member will reach out to the issue owner and coach them on what a quality closure should look like. This process adds value to the organization by creating an expectation on how a notification should be resolved and closed.

b) Ethics & Compliance Helpline

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

Concerns raised with E&C 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 E&C Helpline is part of PG&E’s commitment to foster 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.

c) Material Problem Reporting

PG&E also encourages employees to report and act on problems with any materials, tools, gas, electric, and 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) As 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 2023, the incoming gas MPR's had an average cycle time of 7 days, with a target of 20 days.

Field MPRs are submitted by field personnel from various job sites and PG&E locations who either received a problematic new material or identified a failed part on an asset as applicable. These Field MPRs are evaluated by Gas Engineering. PG&E uses trending from combined MPR data lists to review with subject matter experts (SME). This is in line with the Wildfire Order Instituting Investigation (OII) requirements to trend MPRs generated in the field and allows insight into recurring material issues. Gas Technology Team meetings incorporated field MPR trend review into the agenda in 2023, enabling the timely examination of potential trends and facilitating investigation and corrective actions as applicable. In 2023, the field MPR program resulted in Supplier Quality issuing 22 SCARs and one Purge (a Purge is a PG&E system wide material recall). In 2024, PG&E will continue utilize MPR data and trending with relevant SME technical teams and explore ways to improve the process.

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 2 describes PG&E's Corporate and Gas safety committees and meetings. Gas utilizes the forums described in Table 2 to ensure alignment with the Chief Safety Officer (CSO) and the Chief Risk Officer (CRO) across the enterprise.

Table 2 – Safety Committees and Meetings	
Board of Directors Safety and Nuclear Oversight Committees	Provides oversight and review of (i) policies, practices, goals, issues, risks, and compliance relating to safety (including public, employee and contractor 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.
Safety Weekly Operating Review (WOR)	Provides a forum to focus discussion on Safety related metrics and topics including Serious Injury and Fatality events, learnings, and mitigations and Safety Strategy execution. Participants include the Senior Leadership Team and functional area leaders.
PMVI Daily Operating Review (DOR)	Provides a forum to focus discussion on Preventable Motor Vehicle Incidents, learnings, and mitigations. Participants include functional area leaders who have experienced a PMVI the prior day.
Gas Safety Council	Sponsors initiatives to improve safety across the Gas Functional Area. Monitors Gas safety performance and initiatives to ensure risks are adequately addressed.
Enterprise Grassroots Safety Council	Established the first enterprise-wide grassroots safety council in 2023. This council includes representatives from all functional areas across the Company. The council's focus is on frontline and office workforce safety.
Gas Grassroots Safety Teams	Employee-led, leadership supported, efforts to identify opportunities to improve safety, define and validate possible solutions, and implement and promote safety initiatives.
Training Alignment Committee	Provides a forum comprised of Academy, Gas Operations, IBEW, and Safety Partners, to provide strategic direction on training for Gas Operations as well as to continuously review and monitor Gas Operations training execution. This committee meets monthly to review progress on existing Gas Operations training initiatives and to identify and address emerging issues and training needs.
Safety Partners Meeting	Provides a monthly forum, hosted by PG&E and IBEW leaders, to openly discuss concerns, key initiatives, and opportunities Enterprise Health & Safety has to better support delivery of PG&E's Safety Stand – "Everyone and Everything is Always Safe".
Gas Contractor Safety Committee	Provides a quarterly forum, facilitated by the Gas Contractor Safety team, for collaboration with all gas contractor safety and operations leadership. This meeting is an open environment to discuss key Health and Safety initiatives, new or updated policies/standards/procedures, and Enterprise Contractor Safety team and Operator Qualifications team updates, concerns, and issues. The intent is to improve overall safety in the field with our contractor partners and their subcontractors.
Enterprise Contractor Safety Committee	Provides a monthly forum comprised of Safety Champions and key leadership from all functional areas to discuss recent updates and modifications made to our Enterprise Contractor Safety Management Standard - SAFE-3001S, the associated procedures, and overall compliance with the Kern OII. The meetings are recorded, and notes provided to ensure those unable to participate can still receive updates. Additionally, an Annual Safety Forum is conducted with key contractor leadership and representatives from functional areas with high energy safety risks are present to ensure continued development and maturation of the SIF Capacity Learning Model and associated controls, as well as an improved Safety Culture.

a) Gas Safety Council

In 2023, the Gas Safety Council was held monthly from February through December. This meeting is sponsored by the Senior Vice President, Gas Operations and facilitated by the Senior Director of Gas Safety, Quality and Qualifications. The Council is composed of Senior Leadership including the Senior

Vice President (SVP) of Gas Operations, SVP of Gas Engineering, Vice President of Gas T&D, and the Senior Director of Safety, Quality and Qualifications and Labor Union Leaders from the IBEW Local 1245 and Engineering and Scientists of California (ESC). Invited attendees include the Grassroots Safety Teams,[5] Gas Operations, Gas Safety Excellence, leaders from HR, Gas Engineering, Enterprise Health & Safety, Corporate Safety, and others as needed. The primary objectives are to provide overall governance of safety, to guide department safety strategy, to ensure compliance with Company safety standards, to execute Chairman's Risk and Safety Committee directives, to provide another channel to raise safety concerns, and to promote positive safety culture change.

Throughout 2023, the Gas Safety Council facilitated productive conversation and effective closure of 95 safety concerns and opportunities, including the Everbridge Safety notifications, gas service representative muscle fatigue analysis, rubber glove safety, and using the Proximity Scanner App to identify contaminated site before starting work.

b) GAS GRASSROOTS SAFETY TEAMS

Gas Grassroots Safety Teams are composed of Chairs, Co-Chairs, and members primarily from Gas field positions. The Chairs meet on a regular cadence to discuss issues, strategy, concerns, successes, roadblocks, and any barriers that may exist. As of December 2023, Grassroots had over 239 members. The teams include Field Services, Maintenance & Construction, Locate and Mark, General Construction Gas, Corrosion, Gas Transmission, and Gas Pipeline Operations and Maintenance (GPOM).

Highlights from Gas Grassroots in 2023 include:

- Organized and hosted Driving Rodeos, Mod Zero training, Ergo Days, and Safety Summits across all the PG&E Field Service territory;
- Supported ILI stop work at the Buckeye Station, Live Action Drills, De-Escalation training, and the 4x4 Safety Awareness; and,
- Created and shared safety flash communications highlighting topics such as Slips, Trips, and Fall prevention, Vehicle and Office Ergo evaluations, and Driving safety.

The Grassroots Video team published newsletters and 54 safety videos highlighting significant safety topics including Line of Fire, Keys to Life, Job Safety Awareness, Dealing with Customers, and Joy at Work.

Figure 10 – One PG&E Grassroots Roundtable Meeting Attendees – December 2023 and Grassroots TV Photos

III. Process Safety

Process Safety Management[6] focuses on preventing low frequency, high-consequence incidents and mitigating the consequences from these incidents. The Process Safety Management System consists of four foundational areas (Figure 11): Commit to Process Safety, Understand Hazards and Risk, Manage Risk, and Learn from Experience. The Process Safety Management System is used for engineering new facilities, modifying existing facilities, maintaining equipment, and ensuring safe operation.

Source: The 20 elements of Risk Based Process Safety from CCPS, "Guidelines for Risk Based Process Safety", 2007, AIChE, NY

Figure 11 – The PG&E Process Safety Management System

PG&E is improving process safety performance by strengthening performance in each of these four foundational areas. The Process Safety Management System is well integrated within the GSEMS and enterprise-wide PSEMS [see Section I.3. PG&E *Safety Excellence Management System* and Figure 12 below] to safely manage the planning, construction, operation, decommissioning, and maintenance of gas assets and associated activities and to ensure the safe, reliable, affordable, and clean delivery of natural gas.

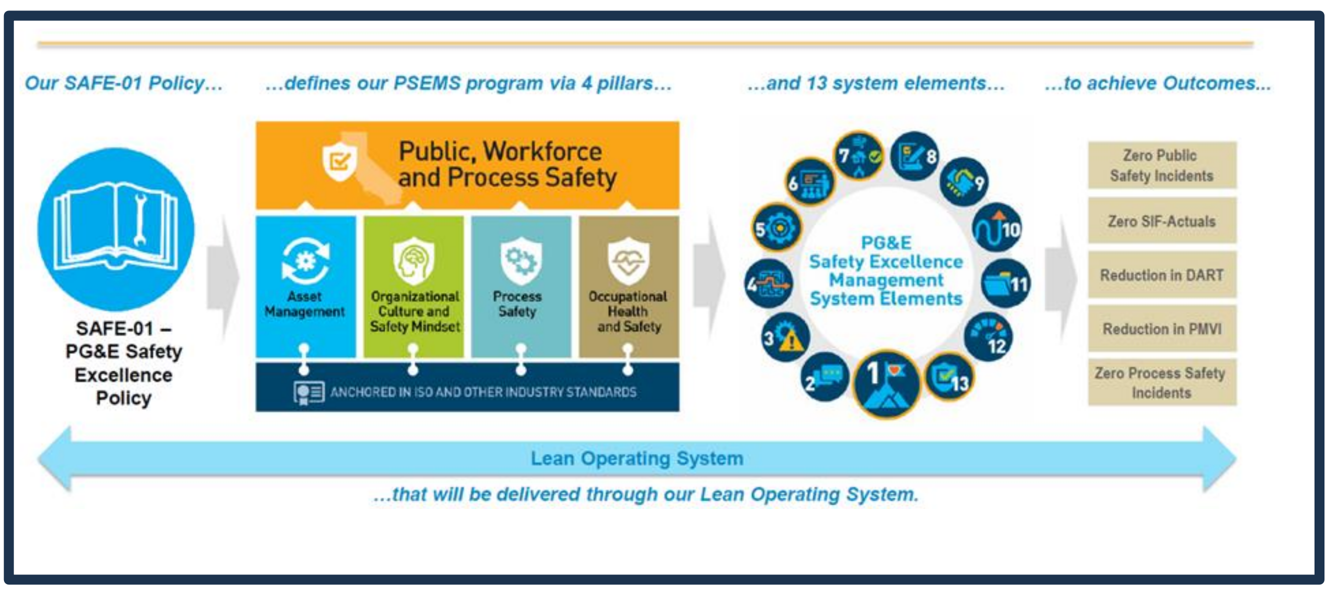


Figure 12 – The PG&E Safety Excellence Management System

2023 Process Safety Highlights

Commit to Process Safety: Guided by the elements set by the Center for Chemical Process Safety, PG&E's continued commitment to implement process safety aligns with API Recommended Practice (RP) 754 *Process Safety Performance Indicators for the Refining and Petrochemical Industries*.[7] To help Gas operate and maintain safe facilities and consistently implement process safety practices, the Gas Process Safety team continued to review new and updated procedures and standards. In addition, Gas Process Safety contributed to the development of the enterprise-wide PSEMS. The PSEMS prevents injury and illness by systematically managing processes, assets, and occupational health. Process Safety is a key pillar to PSEMS (see Figure 12), and the Gas Process Safety team contributed their Process Safety Management expertise and experiences during the development of the PSEMS framework, elements, and manual.

Understand Hazards and Risk: Process Safety Management is a key component in reducing PG&E's operational risk exposure.

The team continued to focus on maturing design risk assessments, simplifying project design-phase Process Hazard Analysis (PHA) activities and checklists, and conducting complex projects and facility PHAs. Identifying hazards and providing effective safeguards (layers of protection) to improve safety and reduce the risk by answering the five Process Safety questions and addressing the energy sources (see Figure 13) helps Gas understand and manage the risk associated with gas engineering designs or facilities activities. In 2023, Gas Engineering conducted PHAs for 100 percent of the 664 applicable projects; 525 in gas distribution and 139 in gas transmission.

Figure 13 – Gas Process Hazard Analysis (PHA) Process

Manage Risk: In 2023, risk mitigation efforts included Management of Change (MOC) (Figure 14) process improvements, Pre-Startup Safety Reviews (PSSRs) and the identification of safety critical equipment (SCE). The MOC improvements focused on ensuring that changes (i.e., permanent, temporary, emergency, organizational) are evaluated to identify hazards and that associated risks are effectively managed.

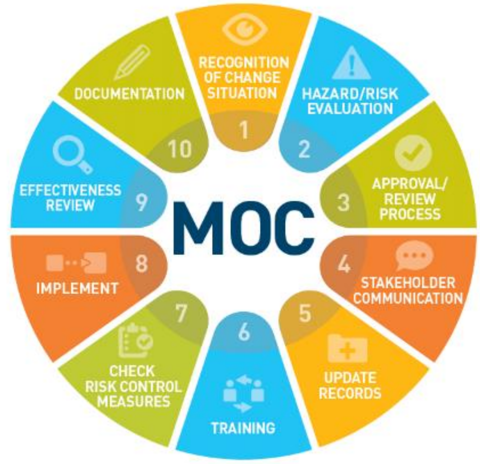


Figure 14 – Gas MOC Process

To ensure identification and mitigation of risk prior to tie-ins, in 2023, Gas Engineering conducted PSSRs for approximately 99 percent of the 176 applicable transmission projects.

Finally, the Gas Process Safety team developed criteria for identifying safety critical equipment (SCE) and worked with the PHA teams to create SCE lists for gas processing and compressor facilities. These SCE lists are used to prompt additional assessments and management of risk prior to project execution.

Learn from Experience: As PG&E endeavors to continuously improve in process safety, Gas Process Safety engineers support incident investigations and cause evaluations on an as-needed basis. Lessons learned from these incidents are shared through Process Safety Moments that are shared regularly during the daily operating reviews or other senior leadership platforms.

In 2023, Gas continued the journey of Process Safety Management maturity. Gas continued to be compliant, per a third-party assessment, with the intent of API RP 754 and Process Safety Performance Indicators, demonstrating a commitment to incident prevention. The Process Safety Indicator (PSI) Dashboard is based on a pyramid framework from the most serious incidents (Tier A) at the top to leading indicators such as issues indicating operating discipline or management system concerns (Tier D) at the bottom of the pyramid (Figure 15). The PSI Dashboard drives ownership and accountability and ensures leading indicators (Tier C and D) are proactively identified and acted upon to prevent a major gas incident (Tier A and B) that can lead to serious injuries, fatalities, or cause significant interruption to the gas business.

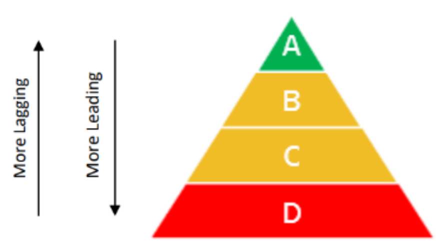


Figure 15 – Pyramid Framework for PSI Dashboard

In addition, the Gas Process Safety team improved the PSI Dashboard functionality, conducted trend analysis for the leading and lagging indicators, and proposed aligning the various leading and lagging indicators metrics among the individual PSI Dashboard Tier levels A through D against the PSEMS elements.

In 2023, the Gas Process Safety team also conducted a GSEMS gap assessment to provide a general health check and gap identification from a systemic point of view for each of the following GSEMS elements/categories and to identify potential broken links between the six selected GSEMS elements and for interactive teams within the same GSEMS element:

1. Process Safety Culture
2. Hazard Identification and Risk Assessment
3. Operating Procedures
4. Training Competency and Awareness
5. Management of Change (MOC)
6. Operational Planning and Controls

A total of 47 recommendations were identified as part of the GSEMS gap assessment that will be managed to completion.

Finally, the Gas Process Safety team continued to identify Gas Incidents (GI) and Process Safety Near Hits and supported further development of the Process Safety Near Hit Program to align with the Gas and enterprise-wide Near Hit Program. The Gas Process Safety Near Hit Program's mission, guided by the Safety Principles and Keys to Life, is to substantially advance the enterprise-wide engagement in the reporting, sharing, and dialogue of Near Hit and hazard events to prevent employee and public safety incidents.

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. There are risks inherent to operating any natural gas system; this is particularly true for PG&E's system that passes through populated areas and a wide variety of terrain. The top three operational risks confronting PG&E's natural gas system are the Loss of Containment on Gas Transmission Pipeline, Loss of Containment on Gas Distribution Main or Service, and Large Over-pressurization Event Downstream of Measurement & Control Facility.[8] PG&E's strategy to address these risks through asset management consists of knowing the assets and their condition, understanding the risks involving those assets, and developing and implementing risk reduction strategies with the intent to achieve risk reduction in balance with operational performance and cost. For this reason, Asset Management and Life Cycle Planning is the second element of PG&E's GSEMS. The following section describes PG&E's asset management system, the asset families, how PG&E's Gas 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 PAS 55: 2008 and ISO 55001: 2014, PG&E's asset management system focuses on:

- Knowing the condition of the assets;
- Understanding the risks to those assets;
- Implementing asset risk reduction strategies;
- Maintaining asset condition and performance; and,
- Balancing asset cost, risk, and performance in pursuit of the asset management strategic objectives.

The Gas Safety Excellence Policy 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-informed Asset Management Plans for each of its nine gas asset families. Finally, PG&E reports regularly to the CPUC on its safety and reliability investments.[9]

2. Asset Family Structure

PG&E continues to use the asset family structure to identify, manage, and mitigate risks faced by the gas assets. The asset family structure also provides a consistent approach for PG&E to address risks. PG&E identified nine asset families within Gas, which are illustrated in Figure 16.

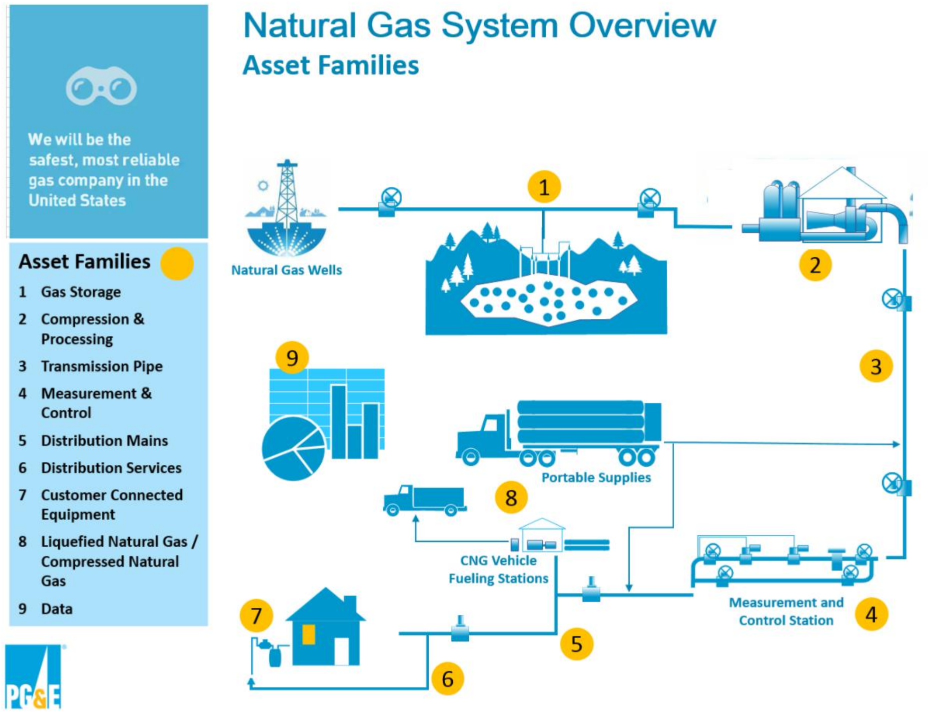


Figure 16 – Natural Gas System Overview – Asset Families

Each asset family has an Asset Family Owner (AFO) who is responsible to understand the asset condition, the risks to the assets, and to develop a risk-informed Asset Management Plan (AMP). An AMP is a five plus year plan for managing gas assets. For 2023 changes to PG&E's AMPs, please see Attachment 03.

The AFO leads the preparation of the AMP 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; and,
- Areas for continual improvement.

The AMPs are living documents that evolve as new asset or risk management information becomes available. The following section summarizes the types of assets in each family, the function these assets serve in the gas system, and the progress towards achieving long-term goals.

a) GAS STORAGE

Presently, 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. The primary assets within this family include 104 storage wells, 14 miles of transmission pipe, well controls for each injection and withdrawal wells, and 3,404 acres of storage reservoirs with over 51.1 billion cubic feet (Bcf) of working gas capacity.

Figure 17 – Rig and Well Platform

Additionally, our current asset structure and reliability model continue to be impacted by new regulations that have initiated major changes to the requirements around design, risk and integrity management, and operations and maintenance for wells and reservoirs. Regulatory decisions related to gas storage continue to be promulgated and are expected to continue to increase and evolve in the coming years.

The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) issued its Final Rules in January 2020, adopting all of the API's RPS 1170[10] and 1171[11] outlining requirements around risk and integrity management, design standards, emergency response, and training. Likewise, the California Geologic Energy Management Division (CalGEM) introduced final regulations effective October 2018 requiring modifications to well design and construction to eliminate the single point of failure changing the configuration of the wells to tubing and packers resulting in an estimated reduction of the withdrawal capacity of about 40 percent. PG&E continues to implement the construction requirement for tubing and packer. PG&E has proposed a risk-based reinspection cycle to CalGEM and is awaiting their approval.[12]

Furthermore, CPUC decision D.19-09-025 in PG&E's 2019 Gas Transmission and Storage (GT&S) Rate Case adopted the Natural Gas Storage Strategy (NGSS) that proposed modified storage services with an effective date of April 1, 2020. The NGSS includes the selling or decommissioning of the Pleasant Creek (2 Bcf working gas) and Los Medanos (11 Bcf working gas) storage fields. On January 31, 2020, PG&E filed Advice Letter 4210-G with the CPUC, outlining the process for selling and/or decommissioning of the Pleasant Creek storage field; PG&E is still engaged in the sale process with an interested party for the sale of the Pleasant Creek Facility. PG&E submitted an 851 filing in July of 2023 and expects the sale to close in 2024. Further, the 2023 General Rate Case (GRC) Final Decision, approved PG&E's request to retain Los Medanos and continue to operate the facility as storage.

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 3.

Table 3 – Gas Storage Asset Management Plan Strategic Objectives and Progress To-Date	
Overall Objective/Goal	**Progress Towards Goal**
Complete baseline well production casing assessments on 104* wells by 2025 ***11 Wells Plugged & Abandoned from 2017-2023, for a net remaining wells of 104**	Number of baseline assessments performed: 2013 – 2016: 27 wells 2017: 8 wells 2018: 13 wells 2019: 15 wells and additional 33 wells not previously assessed for casing integrity inspected using through tubing technology (new) 2020: 20 wells 2021: 17 wells 2022: 18 wells 2023: 22 wells
Evaluate and incorporate Well Risk & Integrity Management Plan (WELL) enhancements	2016: Submitted final WELL documentation to CalGEM for approval and identified improvements to WELL to incorporate in scheduled revisions of the publication 2017: Published updates of WELL to include enhanced design. 2018: Amended WELL and submitted to CalGEM in April 2018. Completed evaluation of final CalGEM regulations when issued. 2019: Revised WELL and filed with CalGEM on 3/31/19 per final regulations for review and approval. 2020: Reviewed and revised WELL with sections re-rewritten as either standards, procedures, or guidance. 2021: Published WELL Rev 6, TD-4870M. 2022: Published necessary updates to TD-4870M. 2023: Restructured and published necessary updates to TD-4870M.
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. 2017: 2019 GT&S Rate Case submission included funding request for strength testing pipeline in the Storage Asset Family. 2018: Replaced 1.65 miles of transmission pipe. (Whiskey Slough east) 2019: No replacement projects due to construction scheduling conflicts. 2020: Installed single line 1.6 miles and removed 2.6 miles of dual lines transmission pipe on the west side of Whiskey Slough. 2021: Installed single line 1.1 miles and removed 2.2 miles of dual lines transmission pipe on the north side of Turner Cut. 2022: Completed Turner Cut South Pipe replacement project. 2023: No storage pipe projects completed.
Continue PHA and PSSR on all well, surface equipment, and pipeline in storage asset family	Number of PHAs and PSSRs complete: 2014: 2 PHAs and 0 PSSRs 2015: 3 PHAs and 7 PSSRs 2016: 4 PHAs and 11 PSSRs 2017: 2 PHAs and 10 PSSRs 2018: 15 PHAs and 5 PSSRs 2019: 24 PHAs and 12 PSSRs; incorporated API RP 754 classifying events according to their tier system. 2020: 38 PHAs, 15 PSSRs 2021: 36 PHAs, 14 PSSRs 2022: 34 PHAs, 20 PSSRs 2023: 21 PHAs, 12 PSSRs

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

b) Compression and Processing

PG&E's Compression and Processing (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 sufficiently dehydrated and odorized so that it can be transported to the gas T&D systems meeting quality requirements. This asset family includes nine transmission compressor stations. Storage compressors are also installed at PG&E's three underground storage facilities.[13] Major assets include 41 company-owned compressor units, as well as associated equipment such as filter-separators, odorizers, pumps, motor control centers, station piping, among others. C&P facilities are critical in maintaining the reliability of the gas system.

Figure 18 – Delevan Compressor Station Turbine Exchange

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

Table 4 – Compression and Processing Asset Management Plan Strategic Objectives and Progress To-Date

Overall Objective/Goal	Progress Towards Goal
Maintain total number of compressor unscheduled outages below 202 in 2023.	Challenges associated with specific units that are now undergoing overhaul and automation. Expect performance improvements upon completion. Target = 202; Actual = 227.
Complete MAOP reconfirmation (ECA2) and/or pressure (strength) testing activities on at least 50 percent of transmission station mileage by July 3, 2028 as required by CFR 192.624(b)(1).	Completed field inspections at 18 locations. Submitted multiple strength test project scopes to execution team.

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

c) Transmission Pipe

The Transmission Pipe asset family consists of approximately 6,400 miles of line pipe and major components, such as valves and fittings, used in transporting natural gas.[14] PG&E's TIMP governs how PG&E identifies threats and evaluates risks, reduces risk through risk mitigation activities, and assesses integrity performance within the Transmission Pipe asset family. The TIMP is a core foundation of PG&E's ongoing efforts to provide safe and reliable service, consistent with industry

Figure 19 – Line 177A Launcher at Harrison Gulch

best practices and based on federal TIMP regulations.[15] 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:

Table 5 – Transmission Pipe Asset Management Plan Strategic Objectives and Progress To-Date	
Overall Objective/Goal	**Progress Towards Goal**
1. Expand the integrity management program to pipelines in HCAs, MCAs, and non-HCA Class 3 & 4 by end of 2034.	• 83 percent of the HCA, MCA, and Class 3 and 4 miles of pipe have had baseline assessments. • 54 percent (3,479 miles) of transmission pipe have been assessed using TIMP methods.
2. Execute TIMP to achieve program objectives of zero incidents and full compliance.	• 0 PHMSA reportable incident in 2023 attributable to Transmission Pipe assets (3 PHMSA reportable incidents total). • Completed 42 miles of 2023 HCA Assessment credit mileage. • 7 missed assessments totaling 0.12 miles.
3. Upgrade 59 percent of the transmission system for in-line inspection devices by end of 2038.	• Strategic objective updated (in alignment with 2023 GRC adopted pace). • 6 completed ILI upgrades resulting in additional 60.75 miles piggable. • In-Line Inspection – inspected 460.6 miles in 2023. • 51.05 percent of the system is piggable (through EOY 2023). • See Section IV.5.g for additional information on in-line inspection.
4. Manage the Corrosion Control system and practices to further reduce the time-dependent corrosion risks by end of 2034.	• Strategic objective updated (risk informed decision to reduce annual pace, shifting end year from 2029 to 2034). • Cathodic protection (CP) availability maintained at 93 percent in 2023. • Conducted Close Interval Surveys (CIS) on 194 miles in 2023, for a total of 67 percent of the system surveyed.
5. Meet 100 percent of system capacity obligations and minimize high risk manual operations in peak day conditions.	• High risk manual operations reduced (from 8 in the 22-23 winter to 5 for the 2023-24 winter). • 8 of 9 transmission regions meet all expected load conditions. • See Section IV.6.a for more information on System Capacity Design Criteria.
6. Update PG&E's gas transmission assets to improve incident mitigation management (IMM) by end of 2030.	• Installed 2 automated valves in 2023. 51 percent system meeting IMM gas evacuation time goal. • See Section IV.7.d for additional information on automated valves.
7. Achieve and 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.

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

On December 14, 2023, the CPUC approved PG&E's proposal to update definitions of Distribution Center, Transmission Line, and Large Volume Customer. These changes will reclassify select assets from Transmission to Distribution. PG&E will implement the change in accordance with CPUC Decision 23-12-003, to include updates of asset records and work plans.

d) MEASUREMENT AND CONTROL

PG&E's M&C assets monitor, measure, and control pressure and flow within the gas T&D 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 20 – M&C Complex Station-Above Ground

The physical assets within this family include three gas terminals, 343 gas transmission stations, 443 transmission large volume customer type facilities, 100 automated valve sites, 2,367 distribution district regulator stations, 1,436 farm taps, as well as over 120 odorizers and over 75 analyzers and other equipment that monitor gas quality. PG&E's M&C equipment is located above and below-ground, including within vaults. As examples, Figure 20 shows a M&C complex transmission station, and Figure 21 shows a large volume customer facility.

Figure 21 – Large Volume Customer Facility

The M&C Asset Management Plan describes PG&E's strategic objectives for the M&C assets. The strategic objectives for M&C assets are the following:

Table 6 – M&C Asset Management Plan Strategic Objectives and Progress To-Date	
Overall Objective/Goal	**Progress Towards Goal**
Develop overpressure risk mitigation plan for stations that serve low customer counts by end of 2023.	• Large overpressure (OP) events per year: 2019 – 11; 2020 – 9; 2021 – 5; 2022 – 9; 2023 – 5. • Published 2023 revision of the OP Long-Term Plan. • Continued installation of secondary overpressure protection devices. Significant progress in installation of token relief valves at large volume customer facilities.
Complete MAOP reconfirmation (ECA2) and/or pressure (strength) testing activities on at least 50 percent of transmission station mileage by July 3, 2028 as required by CFR 192.624(b)(1).	• Completed field inspections at 18 locations and submitted multiple strength test project scopes to execution team.

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

e) Distribution Mains and Services

Figure 22 – Employee Working on Distribution Main and Service

This asset family includes over 44,000 miles of distribution main 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 3.6 million service lines totaling approximately 34,600 miles of pipeline that deliver gas from the distribution mains to the assets in the Customer Connected Equipment family on the downstream side. Combined, the distribution mains and services asset family comprise over 78,600 miles of distribution pipeline – enough pipeline to wrap around the circumference of the earth over 3-times. The Distribution Mains and Services asset family begins at the outlet of the Measurement and Control regulator station assets and ends at the inlet of the distribution service shutoff valve which is where the Customer-Connected Equipment asset family begins. The programs associated with the Distribution Mains and Services asset family are focused on the inspection, maintenance, and replacement or deactivating of Distribution Main and Service assets. PG&E continues to identify and assess threats to Distribution Mains and Services assets using a federal code compliant operational risk model and then works to mitigate those threats, including through its DIMP. Some key strategic objectives include the following:

Table 7 – Key Distribution Mains and Services Metrics

Overall Objective/Goal	Progress Towards Goal
Achieve and maintain 1st quartile for 3rd-party gas dig-ins	PG&E set a third-party dig-in target of 0.98 dig-ins per 1,000 tickets for 2023. In 2023, PG&E experienced 0.98 dig-ins per 1,000 tickets for third-party dig-ins.
Achieve a removal rate of pre-1985 pipe that limits asset age to 100 years by 2030	2010: 27 miles replaced 2011: 24 miles replaced 2012: 49 miles replaced 2013: 71 miles replaced 2014: 66 miles replaced 2015: 105 miles replaced 2016: 127 miles replaced 2017: 145 miles replaced 2018: 163 miles replaced 2019: 126 miles replaced 2020: 131 miles replaced 2021: 191 miles replaced 2022: 202 miles replaced 2023: 112 miles replaced
Reduce the size of emergency shutdown zones (ESZ) in areas that have significant exposure to external hazards by 2023.	Since 2016, PG&E has reduced the percentage of services in emergency shutdown zones greater than 10,000 services by 13 percent. In 2023, PG&E executed 36 new gas distribution valve installations greater than or equal to two inches in diameter.

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

f) Customer Connected Equipment

Figure 23 – PG&E Employee Working on Customer Connected Equipment

The Customer Connected Equipment Asset Family is composed of approximately 4.7 million gas 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.

The Customer Connected Equipment Asset Management Plan provides an overview of the 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 these 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 8.

Table 8 – Key Customer Connected Equipment Metrics	
Overall Objective/Goal	**Progress Towards Goal**
Reach a steady state of 60,000 –70,000 pending non-hazardous meter set leaks for repair annually.	2015 end of year inventory: 66,000 2016 end of year inventory: 63,113 2017 end of year inventory: 59,424 2018 end of year inventory: 84,571 2019 end of year inventory: 106,686 2020 end of year inventory: 152,698 2021 end of year inventory: 158,331 2022 end of year inventory: 159,565 2023 end of year inventory: 178,535
Identify and remove problematic regulators by 2022	At the end of 2023, approximately 735 Cannot Get In (CGI) locations remain requiring special handling to resolve. The 735 remaining units will be included in the 2024 workplan and PG&E will utilize the CGI team to attain customer appointments to mitigate access issues and attempt to complete the outstanding units.
Develop and incorporate DIMP specifications in the purchasing specification for the next generation of SmartMeters, including consideration of seismic shutoff capability.	In 2023, PG&E: • Implemented a pilot of ultrasonic metering with goals to: o Validate safety and reliability; o Evaluate new advanced features (e.g., autonomous shutoff capabilities); and, o Refine field installation processes. • Developed advanced meter infrastructure (AMI) roadmap through completing a focused RFP and vendor selection for future Gas AMI deployment; and, • Partnered with PG&E's IT group to pioneer the AMI system of the future.

The Customer Connected Equipment Asset Management Plan describes these objectives in more detail.

g) Liquefied Natural Gas and Compressed Natural Gas

The Liquefied Natural Gas (LNG)/Compressed Natural Gas (CNG) asset family consists of portable assets that provide natural gas supplies utilizing either LNG and/or CNG to offset or supplement pipeline flowing supplies for planned outages, winter peak load shaving, unplanned outages, and in emergency situations. The LNG/CNG asset family consists of over 200 portable assets with the inclusion of PG&E owned mobile odorization units as well as portable cross compression which is primarily utilized to move isolated methane to an adjacent pipeline reducing overall raw methane emissions during pipeline work. In 2023, there were no loss of containment incidents for portable assets as indicated in Table 9.

Figure 24 – Portable Cross Compression Degassing Isolated Segment of Pipeline into Adjacent Line

Figure 25 – A Large-scale LNG injection Site in Dublin, CA Supporting a Planned Gas Outage

The LNG/CNG asset family also includes 32 CNG station assets to supply high pressure natural gas that fuels PG&E and third-party vehicles while also providing gas supply to our portable CNG assets. In 2014, PG&E instituted an industry-leading inspection program to assure the integrity of customer CNG vehicle fuel systems. In 2023, PG&E remained 100 percent compliant with PG&E owned natural gas vehicle fueling stations. Either the customer submitted their required three-year vehicle certificate of inspection, or the customer's fueling privileges were suspended until the inspection was completed. In 2023, there were no significant loss of containment incidents for CNG Station assets.

Table 9 – Liquefied Natural Gas/Compressed Natural Gas Asset Management Plan Strategic Objectives and Progress-to-Date	
Overall Objective/Goal	**Progress Towards Goal**
Driving towards zero significant LNG/CNG loss of containment incidents	2023 Activities: Continued maintenance, investments, and upgrades of LNG/CNG equipment and assets. Continued LNG/CNG equipment training development and administering including adoption of LNG/CNG apprenticeship program. Continued improvements in quality control program to verify overall effectiveness of maintenance and training programs for LNG/CNG assets.
Implementing an industry-leading inspection program to improve safety inspection certifications to 100 percent of CNG fuel customer vehicles	2023: 100 percent of natural gas fueling customers authorized to fill at our facilities have submitted their three-year cylinder certification to ensure compliance with current Federal Motor Vehicle safety standards.
Reduce risk of portable natural gas transportation traffic incidents by reducing equipment issues through an improved maintenance program	2023: Continued maintenance of LNG/CNG portable over-the-road assets by dedicated fleet mechanics with Transportation Services. Hazardous material transport trailer quality control program continues to be in place to verify overall effectiveness of the below the deck maintenance program.

The LNG/CNG Asset Management Plan describes these objectives in more detail.

h) Data

In 2018, PG&E Gas 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 datasets 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.

In 2020, PG&E established an Enterprise Data Management (EDM) organization, and in 2022, the role of the Chief Data and Analytics officer (CDAO) was expanded to include the IT role of Chief Security (CSO) officer now reporting to SVP and Chief Information Officer (CIO) in IT. EDM retains the responsibility for developing the enterprise level data strategy, policies, standards, and objectives. Implementation of these objectives will be led by the Gas Data Management organization in partnership with the EDM team, our IT business partners, and Gas business units. Such centralization of the data management function ensures alignment of data strategies and improves PG&E's ability to make data-driven decisions around reducing risk within our systems.

PG&E contracted with Palantir to implement the Foundry enterprise data platform to centralize, curate, and transform data into business insights through creation of data products. Foundry currently is connected to over 50 Gas, Electric, and Customer Care focused source systems, which contain billions of records relevant to asset health analytics such as Geographic Information System (GIS) and SAP. The data platform does not replace the underlying source data systems of record, but rather provides a central platform to enable data integration/visualization and access and support for data management and advanced analytics to visualize records in the two systems. Key metrics were established with IT and the EDM team.

Key Metrics are presented in Table 10. Strategic goals, and progress towards those goals are listed in Table 11.

Table 10 – Key Data Asset Metrics for 2023	
Overall Objective/Goal	**Progress Towards Goal to Date**

Complete Phase 1 certification for 21 data sets	• 21 Datasets completed
	  ○ Target: 100%
	  ○ Actual: 100%
	• 1,094 CDEs collected
	  ○ Target: 100%
	  ○ Actual: 100%

Data Quality Key Performance Indicators (KPIs)	• At least 1 data quality rule applied (EDM KPI 1b):
	  ○ Target: 50%
	  ○ Actual: 55%
	• Overall coverage applicable to Data Quality Rules; Conformity, Uniqueness, Completeness (EDM KPI 2)
	  ○ Target: 20%
	  ○ Actual: 38%
	• Document publication of TD-5001S:
	  ○ On hold due to cancelation of GOV-9001S and GOV-9002S.
	• Percentage complete of change management plan:
	  ○ Target: 100%
	  ○ Actual: 91.67%

Table 11 – Data Asset Management Plan Strategic Objectives and Progress to Date	
Overall Objective/Goal	**Progress Towards Goal**
Continue Implementation of Data Stewardship in alignment with the Enterprise Data Strategy and reach GSEMS level 4 maturity by the end of 2028.	**Created Data Quality Rules in Conjunction With SMEs to Assess and Monitor Data Health:** • 2,308 Data Quality Rules measured • 1,509 Critical Data Elements measured • 52 Critical Datasets assessed **Predictive Predicate Modeling Tool:** • Built and began implementation of tool to predict and profile metadata for faster and more efficient throughput. **Onboarded Team of Contractors to Continue to Collect Metadata and Create Data Quality Rules:** • 5 analyst contractors and 1 project manager
Develop and implement the data governance framework to improve underlying data quality to effectively manage risk outcomes for all Gas asset families by the end of 2028.	**Strategic Data Plans:** • Developed and began piloting Strategic Data Plans to support operationalization of the asset register, support the identification of data quality elements, and enhance communication streams for data asset owners. **Governance Charter:** • Developed and socialized for early feedback. **Data Governance Lead Position:** • EDM has hired a shared Data Governance Lead to support Gas and Power Generation.
Implement advanced data analytics platform that enables big data analysis and provides actionable insights. Foundational data from SAP, CC&B and GIS to be ingested with Level 2 (reusable) ontology into advanced data analytics platform by end of 2024.	**107 Objects Currently in Foundry:** • 67 at Level 2 Public Class (available for use and reusable) • 40 (still in progress) **2 Products Deployed:** • GIS/SAP Reconciliation Dashboard • GC Overlay **Use Cases in Progress:** • GIS/SAP Misalignment • GC Overlay • GPOM Predictive ML Model **Value Stacking:** • Allows us to bring in a dataset once but be able to utilize it for unlimited projects.
Develop and execute an annual portfolio of data quality improvement projects with supporting processes and do so in a way that is strategic, and risk informed.	**SAP-GIS Data Remediation and Alignment:** • Leveraging dashboard built in foundry. • Using data quality rules to track progress. • Onboarded & trained contract team to support remediation efforts increasing team size to 19. **Cleanup of Accurate Reconciliation of Meters and Services:** • Services placed as a part of Remedy 12 & 13 to document potential services missing from the map. • Potential services cause many issues for Locate and Mark, Estimating, and Mapping. • Remediation of existing services and validation of new locations identified.

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

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 (EORM) 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 EORM plans allow PG&E to manage assets and risks at an enterprise and operational level. PG&E defines "Enterprise Risk" as any risk that could potentially have a catastrophic impact to the company. PG&E's Board of Directors (BOD) provide oversight for Enterprise Risks through annual and ad-hoc risk reviews.

All operational risks are actively managed at the Functional Area level, with oversight provided by each Functional Area's Risk and Compliance Committee (RCC), which at a minimum, meet quarterly. In 2023, the Gas RCC met monthly. Each Functional Area's RCC is charged with oversight of risk management activities within the Functional Area including, but not limited to, reviewing risk assessments, approving risk response plans, and overseeing their implementation. By assessing and managing risks from PG&E's BOD and Gas RCC management, PG&E can better manage the interdependencies and drive for consistency in risk management across the Company. In addition, the EORM team leverages several executive forums[16] to ensure governance of the EORM and awareness of enterprise risks across the executive team. The annual governance plan supports BOD oversight of Enterprise Risks and provides oversight for the remainder of the Corporate Risk Register. Elements of the work plan include risk management program strategy, deep dives, and challenge sessions for specific top risks. This process increases Senior Management and BOD 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 across the enterprise.

Gas identifies, assesses, and ranks its risks in a Corporate Risk Register in accordance with EORM guidelines. The Gas risks within the Corporate Risk Register are governed by the Gas RCC. In 2023, PG&E initiated a new Executive Risk Command Center where Gas risks can be discussed with PG&E's senior leadership team. Risks, for each asset family identified during an annual risk refresh, are captured within the Asset Management Plans, mitigation programs, and work projects. As the result of the annual risk refresh process, Gas identified nine operational risks as part of the Corporate Risk Register for 2023, which were not changed from 2022. These risks are summarized in Table 12 below.

Table 12 – 2023 Gas Risks in the Corporate Risk Register	
Risk	**Description of Risk and Risk Drivers**
Loss of Containment on Gas Transmission Pipeline	Failure of a gas transmission pipeline resulting in a loss of containment, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and the inability to deliver natural gas to customers. Drivers include: Equipment Failure, External/Internal Corrosion, Incorrect Operations, Manufacturing Defects, Stress Corrosion Cracking (SCC), Third Party/Mechanical Damage, Weather Related and Outside Force Threats, and Construction Threats.
Loss of Containment on Gas Distribution Main or Service	Failure of a gas distribution main or service resulting in a loss of containment, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and the inability to deliver natural gas to customers. Drivers include: Equipment Failure, Corrosion, Incorrect Operation, Excavation Damage, Material Failure of the Distribution Pipeline or Weld, Natural or Other Outside Force, and Cross Bore.
Large OP Event Downstream of Gas Measurement & Control Facility	Failure of a Gas M&C facility to perform its pressure control function resulting in a large OP event downstream that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and the inability to deliver natural gas to customers. Drivers include: Equipment Related and Incorrect Operations.
Loss of Containment on Gas Customer Connected Equipment	Failure of gas customer connected equipment resulting in a loss of containment, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and the inability to deliver natural gas to customers. Drivers include: Corrosion, Equipment Failure, Incorrect Operation, Material/Weld Fail, Natural or Other Outside Force.
Loss of Containment at Natural Gas Storage Well or Reservoir	Failure at a gas storage well or reservoir resulting in loss of containment, with or without an unplanned ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and the inability to deliver natural gas to customers. Drivers include: 1st/2nd/3rd Party Mechanical Damage, Incorrect Operations, Casing Wall Loss, Equipment Related, Manufacturing Related Defects, Weather Related/Outside Forces, and Welding/Fabrication Related.
Loss of Containment at Gas M&C or Compression and Processing Facility	Failure at a Gas M&C or Compression and Processing station resulting in a loss of containment that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and the inability to deliver natural gas to customers. Drivers include: Incorrect Operations, Welding/Fabrication Related, External/Internal Corrosion, SCC, Third-Party/Mechanical Damage, Weather Related/Outside Forces, Manufacturing Related Defects, and Equipment Related.
Loss of Containment on CNG Station Equipment	Failure of CNG station equipment during operations resulting in a loss of containment that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and the inability to deliver natural gas to customers. Drivers include: Third Party Damage, Equipment Related, Incorrect Operations, and Corrosion.
Loss of Containment on LNG/CNG Portable Equipment	Failure of LNG/CNG portable equipment during operations resulting in a loss of containment that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and the inability to deliver natural gas to customers. Drivers include: Equipment Related, Incorrect Operations, Corrosion.
Insufficient Capacity to Meet Customer Demand	Failure to maintain capacity on the system on high demand days. Drivers include: Pipeline Outage, Integrity Finding, Delayed/Deferred Capacity Projects, Inadequate Design, Design Deviation, and Unexpected System Restriction.

Factors impacting more than one risk as a unique risk driver, or a component of an existing risk driver, are called Cross-Cutting Factors. As such, these factors can impact the likelihood or consequence of a risk event. The Cross-Cutting Factors are owned by a single functional area, with other impacted functional area(s) providing their input and subject matter expertise. These factors also follow the EORM process. Gas is impacted by several Cross-Cutting Factors owned by other functional areas as displayed in Table 13 below.

Table 13 – Enterprise Risk Management: Cross-Cutting Factors

Cross-Cutting Factor	Description
Seismic	Seismic events can be a significant driver of failure in all functional area assets. Seismic events contribute to the likelihood of asset failure events and to the associated safety, reliability, and financial consequences of those events.
Cybersecurity Incident	A coordinated malicious attack purposefully targeting PG&E's core business functions, resulting in loss of control of Company information or systems used for gas, electric, or business operations. The consequences of a cyber-attack are potentially catastrophic and could impact the safety and reliability of PG&E's operational systems.
Skilled and Qualified Workforce	Impact of Human Performance, workforce continuity, and employee skills and qualifications that affect PG&E's risk drivers and consequences.
IT Asset Failure	Failure of IT systems or infrastructure, resulting in outages, system unavailability for mission critical assets impacting operations, or the ability to support public safety events.
Records and Information Management (RIM)	The risk of not having an effective RIM program may result in the failure to construct, operate, and maintain a safe system and may lead to property damage and/or loss of life.
Physical Attack	Incidents related to break-ins, vandalism, theft, fraud, assault, and threats against PG&E's workforce and assets.
Emergency Preparedness and Response	Examines the drivers and consequences of inadequate planning or response to catastrophic emergencies. Inadequate emergency planning or response could have significant safety, reliability, and regulatory impacts.
Climate Change	Climate change presents ongoing and future risks to PG&E's assets, operations, employees, customers, and the communities it serves.

Through external regulatory changes, PG&E continues to improve its risk management process and is an active participant in the CPUC's proceedings to advance a "risk-informed" process. In D.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 and 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 2020 RAMP report on June 30, 2020, which was the initial phase of PG&E's 2023 General Rate Case. The 2020 RAMP report represented progress on the joint efforts of the Commission and its Safety Policy Division, PG&E, California's other large investor-owned utilities (IOU), and other stakeholders over the past several years to enhance risk-informed decision-making through the S-MAP and RAMP reports. The 2020 RAMP report reflected PG&E's first implementation of the methodologies adopted in the S-MAP Settlement Decision (D.18-12-014).

On December 15, 2022, the CPUC issued Decision (D.) 22-12-027 on Phase II of the Risk-Based Decision-Making Framework OIR to further develop a Risk-Based Decision-Making Framework (RDF) for Electric and Gas Utilities (R.20-07-013). This Decision replaces the previous 2018 S-MAP Settlement Agreement with a modified Risk-Based Decision-Making Framework document that details the minimum requirements for an IOU's RAMP report. A key change in the decision is a shift from a Multi-Attribute Value Function (MAVF) approach to a Cost-Benefit Approach that includes standardized dollar valuations of safety, electric reliability, and gas reliability consequences from risk events. This change, along with other RDF refinements made in the decision, are intended to further increase transparency, participation, and accountability into how safety risks for energy utilities are managed, mitigated, and minimized. PG&E incorporated the new requirements from this Decision in 2023 and is scheduled to file the 2024 RAMP In May 2024.

4. Records and Information Management

PG&E's Enterprise Records and Information Management (ERIM) Program focus is to reduce risk and increase trust in the company's information and records by providing clear governance, change management and process improvement, and effective technology and tools. This includes 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 and implement tools to manage the lifecycle of records. Examples of ERIM accomplishments in partnership with the Gas functional area in 2023 include:

- Continued physical records remediation in field offices and provided local support during decommissioning and reconfiguration of PG&E sites;
- Validated 174 (54%) of 322 Gas records in the Enterprise Records Inventory;
- Migrated 3,220,000 records from Documentum on-prem to Centralized Records Management (CRM) Cloud for 2 applications: Gas – Distribution As-Built Records (GDARC) and Material Traceability (MT);
- Piloted a new Information Governance model and assessment with Gas Systems Operations (Gas Operations) and Asset Knowledge Management (Gas Engineering), which included 33 survey respondents and 9 interviews; and,
- Destroyed 215 boxes of eligible inactive Gas records through the physical records disposition process.

The Community of Records Advocates (CORA) formally known as the RIM Ambassador Network, composed of ERIM staff and representatives from Gas and other Functional Areas continues to be an effective way of communicating records management information and best practices throughout the organization. In addition to the mandatory information and records training that all PG&E employees receive, the ERIM team provides monthly training and discussions on general information and records management practices through their Knowledge Center course offerings. These offerings are available to all PG&E employees. Additionally, ERIM personnel support all Functional Areas and all regions throughout PG&E by providing records management training and guidance.

ERIM maintains comprehensive 5-year roadmaps listing projects and initiatives that support our mission and goals. Table 14 highlights key ERIM projects and programs, with the drivers for work impacting the Gas functional area in 2024.

Table 14 – Gas Records and Information Management Roadmap Highlights

Roadmap Projects & Programs	Roadmap Drivers
Documentum Repository Consolidation	• Documentum stability and support, improved functionality, and new features. • Simplified data structure to support functional implementation. • PG&E's Records Information Management standards (GOV-7000 series).
ERIM Program Compliance	• Information Governance Maturity Model & Framework • PG&E's Records Information Management standards (GOV-7000 series) • California Privacy Rights Act (CPRA)
Information Governance Model Assessments	
Physical Records Disposition Execution	
Data Disposition	

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 workgroups collaborating to educate excavation 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 and Mark, Standby Governance and Pipeline Patrol.

Damage Prevention includes marking the field location of underground facilities as requested through the Underground Service Alert (USA) system (commonly referred to as 811), USA ticket management, investigations associated with excavation damages (commonly referred to as dig-ins) and damage claims, monitoring excavations in proximity to critical infrastructure, and Public Awareness. The marking of underground utilities is governed by California Government Code Section 4216 et seq. and the process is driven by regulatory requirements and industry best practices. Table 15 describes other key Damage Prevention programs.

Table 15 – 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 notified 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. They request all excavation be stopped, educate the excavator about the requirements of California's One Call Law and the reason for the non-compliance, provide excavation safety materials, and instruct the excavator to correct the non-compliance activity prior to continuing any excavation. In 2023, the Damage Prevention Hotline received 605 calls.
Damage Prevention Institute	The Damage Prevention Institute (DPI) identifies best practices in excavation safety and sets safety criteria that second-party contractors are required to meet to be eligible to do work on behalf of the Utility. PG&E and their contractors participation in DPI is one way that PG&E is helping to make communities safer. PG&E requires its contractors excavating on behalf of PG&E to maintain the DPI accreditation. PG&E acknowledges all contractors who practice safe excavation and monitors offenders who fail to demonstrate safe practices. Unsafe contractors are unable to perform work on behalf of PG&E.
Procedures, Guidance and Training	Providing clear and concise instruction around dig-in prevention measures like troubleshooting "difficult to locate" facilities, documenting field activities and how to properly respond to a USA ticket.

In addition, since 2014, PG&E has improved its "Shut-In The 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 The 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. Plan of Reorganization (D.20-05-053) called for the development of Safety and Operational Metrics to be used in conjunction with the adopted Enhanced Oversight and Enforcement Process to ensure progress is being made on key safety and operation metrics. In 2022, PG&E began reporting the median Shut-In The Gas Performance versus the average. In 2023, PG&E's median Shut-In The Gas Performance was 35.3 minutes for services and 80.0 minutes for mains.

Table 16 – Shut-In The Gas Performance (median number of minutes)										
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Services	38.0	40.0	37.0	36.0	37.2	36.8	36.7	36.3	36.8	35.3
Mains	97.0	87.0	87.0	89.0	76.1	76.0	79.2	79.1	82.1	80.0

Since 2014, PG&E has improved its overall make safe performance on events involving services by 7 percent, and events involving mains by 18 percent.

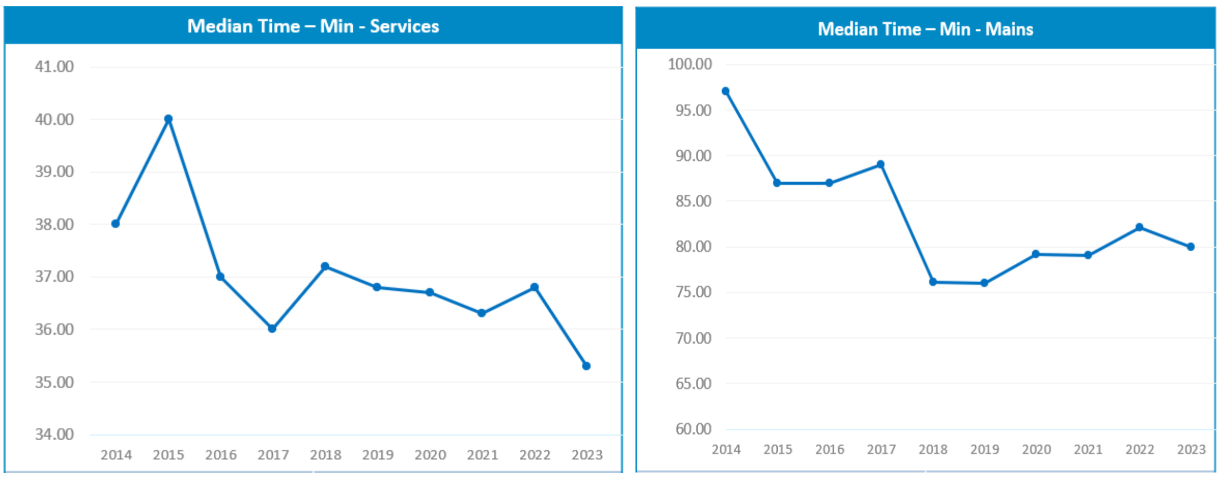


Figure 26 – Shut-In The Gas Performance

PG&E will continue its efforts to improve its Shut-In The Gas Performance. In addition to Shut-In the Gas performance, PG&E began measuring the Time to Resolve Hazardous conditions in 2022 as part of the Safety Operational Metrics. This metric measures the median response time to resolve a Grade 1 leak. PG&E's median Time to Resolve Hazardous Condition performance was 141.0 minutes for 2023, a 15 percent improvement compared to 2022 median time of 165.3 minutes.

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 and press releases.

PG&E conducted 392 "811 Call Before You Dig" contractor workshops, reaching 5,297 attendees at 374 companies

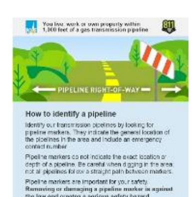


Figure 27 – Screenshot of 811 Awareness Contact Sent to Customers

PG&E communicates gas safety information multiple times each year, and in 2023, reached approximately 3 million paper bill customers and sent approximately 3 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 and email to over 1.3 million businesses and residences 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, master meter accounts, and those who live or work near PG&E's storage and compressor facilities. Table 17 identifies highlights from the Public Awareness Program's 2023 activities.

Table 17 – 2023 Public Awareness Program Highlights
Continued posting weekly 811 awareness messaging on the NextDoor app, targeting zip codes where pipeline damages were caused by homeowners who did not have a one-call ticket, resulting in over 1.6 million impressions.
Executed 9 different social media campaigns targeting homeowners and contractors throughout PG&''s service territory, promoting the importance of calling 811 before digging. These campaigns resulted in over 11.6 million impressions.
Completed 11 bilingual 811 workshops, with 528 participants, in partnership with local Spanish language radio stations. Conducted an interview with each radio station to further expand on the 811 free service.
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 7,482 field visits by Dig-in Reduction Team (DiRT) Investigators.

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 excavators responsible for excavation damage. The DiRT is part of a proactive program that directly and positively affects public and employee safety by striving to reduce the number of excavation damage incidents through outreach, education, and incident investigations. PG&E's Dig-In Reduction programs were instrumental in managing the number of third-party gas dig-ins per 1,000 USA tickets at 1.04 in 2019, 1.05 in 2020, 0.91 in 2021, 0.87 in 2022 and 0.98 in 2023.

Table 18 below provides information on some dig-in prevention projects or process improvements.

Table 18 – Dig-In Reduction Team Programs Under Damage Prevention	
PG&E's Commitment to Safety	**Promoting Safety**
DiRT Investigations	Deploys investigators to oversee and enhance PG&E's ability to investigate dig-ins, patrol active excavations, and intervene when unsafe excavation activities are identified.
Pipeline Patrol	Identifies and intercepts surface 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	Conduct safe digging workshops throughout the service territory.

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 two working-day window. Federal pipeline safety regulations[17] and California state law[18] 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, including natural gas, electric, and fiber optic. 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 notification centers which share a common toll-free, 3-digit "811" telephone number. The California one-call systems are commonly referred to as USA. In 2023, PG&E received over 1.3 million USA ticket notifications, a slight reduction from approximately 1.58 million USA ticket notifications in 2022.

Figure 28 – PG&E Coworker Marking a Gas Main and Service

PG&E has been, and continues to be, on a mission to improve its safety, ethics, and compliance culture and to foster a non-retaliatory environment where all employees can confidently and safely speak up. Leaders are consistently listening to and following up on issues raised by employees. PG&E is steadfastly committed to this important work.

iv. Standby Governance

Standby Governance is part of PG&E's internal damage prevention process to meet requirements of 49 CFR Part 196. Excavators working near PG&E high-priority or critical facilities are required to ensure safe excavation practices per California Government Code § 4216 and to ensure that PG&E procedures are followed.

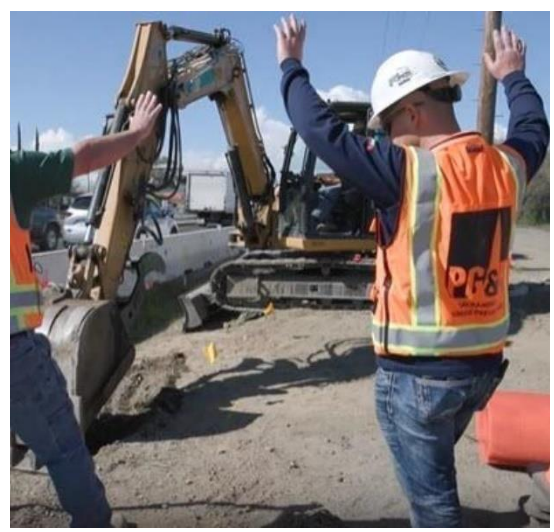


Figure 29 – Standby Crew at Work During Excavation

Standby is a free service provided to excavators. Standby inspectors serve as an objective representative of the utility on site to observe and protect PG&E facilities.

However, the standby role goes well beyond simply observing and ensuring safe excavation. It is important for a standby inspector to understand the complexities of each job to ensure the safety of the public, coworkers, and PG&E's assets. The standby inspector is familiar with general safe excavation practices, PG&E procedures and how to apply them. Additionally, a standby inspector may need to intervene to stop work if they identify any unsafe activities that may jeopardize PG&E facilities, the crew, or the public.

The Standby Governance Team supported 4,822 standby jobs in 2023. While each standby was conducted to protect PG&E's critical infrastructure, each standby also provided an opportunity to build relationships with excavators and educate the excavator community on safe digging practices.

v. PIPELINE PATROL

Pipeline Patrol is a federally required activity that is essential to protect the integrity of PG&E gas transmission facilities from external threats. The activity helps to increase public safety. Patrol is performed both by air and ground by operator-qualified personnel who observe surface conditions on or near the rights of way of buried pipelines. Patrollers identify and respond to excavation activity (e.g., digging, ripping, boring, blasting, etc.) in order to notify excavators that they are digging in the vicinity of pipelines, and in the case of unauthorized digging, to educate and direct the use of the Underground Service Alert System.

Patrollers also report on surface conditions that could cause damage to company facilities, such as land movement, or could cause a change in class location, such as new construction, that may affect identification of High Consequence Areas.

PG&E primarily utilizes aerial methods to conduct patrols, with ground personnel dispatched to investigate observations made from the air. 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 identify and stop unsafe excavation practices before dig-ins occur.

Figure 30 – Example of Land Movement

Figure 31 – Patrol Fixed Wing Aircraft

Figure 32 – Patrol Helicopter

PG&E patrols using a combination of fixed-wing aircraft and helicopters. In 2023, 21 percent of ground observations were related to excavation, 48 percent were related to new construction, and the remaining 31 percent were related to include right of way (ROW) encroachments, geohazards, and other miscellaneous observations requiring further ground evaluation.

b) Pipeline Markers

Pipeline markers and indicators are important damage prevention tools used to indicate the approximate locations of pipelines along their routes to prevent "dig-ins" from occurring. The markers and indicators also advise the public of pipeline rights of way. Pipeline safety regulations require installation of markers because markers contribute to public awareness and damage prevention, which in-turn reduce the risk of loss of containment.

Figure 33 – Pipeline Marker

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, navigable 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 34.

Figure 34 – 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.

c) Distribution Pipeline Replacement

As shown in Table 19, PG&E has three pipeline replacement programs: Gas Pipeline Replacement Program (GPRP), Plastic Pipe Replacement Program, and Main Replacement Reliability Program. An important element of providing safe gas distribution service is replacing aging or at-risk assets. PG&E uses relative risk to prioritize its pipeline replacement projects so that the sections of pipe with the highest risk are replaced first. The risk ranking for the Plastic Pipe Replacement Program is based on a methodology that considers leak history, pipe age, material type, ground temperature, diameter, operating pressure, and population proximity. The risk ranking for the Gas Pipeline Replacement Program (GPRP) is based on a methodology that considers pipe age, leak history, cathodic protection, coating, seismic activities, and population proximity. In addition to gas main replacement, the programs cover related service replacement and meter relocation work.

PG&E's objective is to achieve a removal rate (replacement or deactivation) of pre-1985 pipe that limits asset age to nearly 100 years by 2030 considering cost-effective electrification. Assuming this removal rate, all remaining miles of known pre-1985 Aldyl-A and other plastic pipe are anticipated to be removed by approximately 2050, which is closely aligned to mitigate all pre-1985 plastic pipe prior to the 71-year mean-time-to-failure shown in the CPUC's analysis in its "Hazard Analysis & Mitigation Report on Aldyl-A Polyethylene Gas Pipelines in California."

With enough natural gas distribution pipe traversing underneath the ground to wrap around the circumference of the earth over 3-times, a holistic approach that incorporates the condition of these assets and the risks to these assets must be considered. Then implementing asset risk reduction strategies over a significant timeframe (half a century or more) is crucial. Absent prudent asset management, a time will come where short-term and reactive needs result in an asset failure rate that exceeds the capacity of the skilled and qualified workforce and exceeds a reasonable cost burden that rate payers are willing to pay over a short period of time to replace or repair the failed assets. This could result in an increase in the number of significant incidents because of loss of containment on these aging assets.

Table 19 – Distribution Pipeline Replacement[(a)]		
Gas Pipeline Replacement Program (GPRP)	**Plastic Pipe Replacement Program**	**Main Replacement Reliability Program**
PG&E began the GPRP Program in 1985, which has 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; however, PG&E may also include post-1940 higher risk steel projects based on risk modelling. In 2023, the GPRP Program replaced 17.7 miles of pipe.	Since PG&E began its Plastic Pipe Replacement Program in 2012, PG&E has replaced over 970 miles. In 2023, 84.2 miles of pre-1985 plastic pipe was replaced.	The Main Replacement Reliability Program focuses on the replacement of pipeline not covered by the GPRP or pre-1985 plastic pipe replacement programs. In 2023, PG&E replaced 9.5 miles of distribution pipe through this program.
(a) Pipe replacement and deactivation additionally occurs under leak repair, reliability, emergent work, and emergency response programs for which the mileage is not included.		

Figure 35, below, demonstrates the Company's main replacement progress from 2010 to 2023.

Main Replacement 2010-2023 Actuals

Program			2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
14A	GPRP	Replacement of all cast iron and some steel main installed pre-1941	23.3	19.4	23.4	31.6	26.8	27.5	30.4	35.8	43.6	20.0	23.9	36.4	23.2	17.7
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	91.2	90.1	87.6	136.3	163.9	84.2
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	3.6	4.2	7.9	8.6	6.6	13.7	15.8	14.1	28.6	15.8	19.3	18.2	15.5	9.5
Total			27.0	23.6	48.9	70.9	66.0	104.7	126.6	145.0	163.4	125.8	130.7	190.8	202.5	111.5

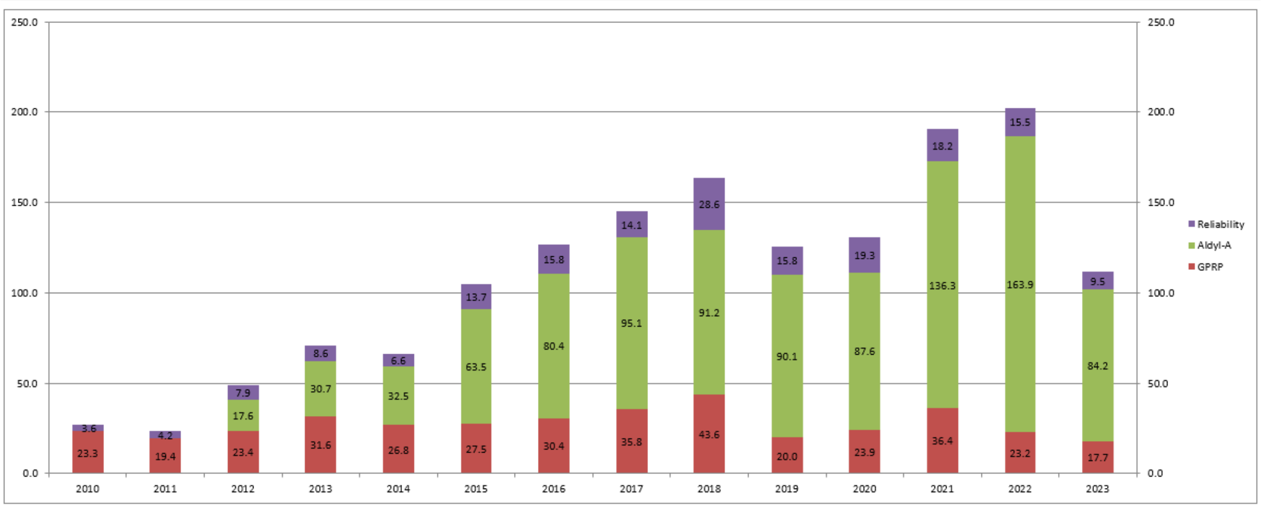


Figure 35 – Main Replacement Progress 2010-2023 (in miles)

d) Cross-Bore Mitigation

A cross-bore[19] 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 that 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	19,298	148	25,000
2014	35,895	188	38,000
2015	23,530	100	24,000
2016	22,981	94	23,570
2017	35,628	55	30,000
2018	46,043	46	42,500
2019	44,213	37	41,636
2020	16,814	56	15,000
2021	28,092	33	27,532
2022	49,705	29	48,500
2023	8,655	29	12,672

Figure 36 – 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 8,655 inspections in 2023. In 2023, PG&E found approximately 1 cross-bore per 298 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 consistent with and pursuant to 49 CFR, Part 192, Subpart J testing and documentation requirements or Minimum Test Pressures for Existing Pipelines in High Consequence Areas (HCAs) to meet the Seven Year Integrity Assessment Interval per American Society of Mechanical Engineers (ASME) B31.8S-2004, Section 5, Table 3. This process also results in a test record that establishes the operating pressures the pipe can withstand. A secondary benefit of strength testing 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, strength testing is one tool PG&E uses to

Figure 37 – Strength Test in Progress

maintain the margin 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 continues to strength test or replace untested transmission pipelines in compliance with Pub. Util. Code Section 958. In 2023, PG&E completed approximately 23 miles of strength testing (Table 20), of which 11.98 miles were re-tested for specific Integrity Management (IM) purposes. This work brings PG&E to a total of approximately 1,614 miles strength tested since 2011 which brings the total miles of transmission pipe with test records to approximately 93 percent. The pipeline miles strength tested in 2023 were prioritized based on a risk informed mix of integrity management threats and testing untested pipe lacking a traceable, verifiable, and complete record to meet the NTSB D.11-06-017 requirements.

Table 20 – Transmission Pipeline Miles Strength Tested (miles)

Strength Test	2011-2014	2015-2022	2023	Total
PSEP	674	N/A	N/A	674
Subsequent Testing	0	917	23	940
Total	**674**	**917**	**23**	**1,614**

PG&E has strength-tested or verified strength-test records for our pipelines to complete all the NTSB requirements from Safety Recommendation P-10-4. PG&E will continue to utilize strength testing to re-assess pipeline segments with integrity management threats for both manufacturing related defects and time dependent corrosion threats, and to comply with the MAOP reconfirmation requirements of 192.624.

f) Vintage Pipe Replacement

The Vintage Pipe Replacement program was established in 2015. At that time, 47 percent of PG&E's natural gas transmission pipeline system consisted of pipelines designed, manufactured, constructed, and installed before the advent of California's 1961 pipeline safety laws. While age alone is not an indicator of poor asset health, the original installation year can be useful indicator of the manufacturing and construction practices and technologies used during that era. Consistent with industry practice, vintage construction features generally do not pose a threat unless "activated" by a change in service conditions, such as axial loading or ground movement. PG&E considers high risk vintage pipeline as pipeline assets manufactured or constructed and fabricated using historic practices, such as, but not limited to, oxyacetylene welds, wrinkle bends, and non-standard fittings that are located in areas subject to land movement and most appropriately managed through replacement.

PG&E's Vintage Pipe Replacement program vision is to address the risk of pipe segments containing vintage fabrication and construction threats that have a high likelihood of interacting with land movement within populated areas. In 2019, PG&E identified approximately 123 miles of high-risk Tier 1 and Tier 2 transmission pipe.[20] PG&E plans to replace or retire 100 miles and continue to monitor the remaining 23 miles. As of 2023, the program has replaced or retired 98.75 miles of "Tier 1" and "Tier 2" high-risk vintage fabrication and construction threats interacting with high likelihood of land movement.[21]

Figure 38 – Vintage Pipe Replaced in San Mateo

Table 21 – 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
2019	2.06 miles	0.75 miles	75 percent
2020	1.32 miles	0 miles	77 percent
2021	3.22 miles	0 miles	78 percent
2022	0.15 miles	0 miles	79 percent
2023	0.05 miles	0.01 miles	80 percent
Program Target:	123 miles		100 percent

(a) High risk mileage addressed includes retirements and mileage replaced in other pipe replacement programs from 2015-2023 that had an identified vintage threat.

PG&E continues to enhance risk methodology used to monitor and assess characteristics of vintage pipelines interacting with land movement by improving data quality and collection.

g) In-Line Inspection

PG&E's ILI Program uses technologically advanced inspection tools, often called "smart pigs," to assess the 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 installation of "launchers" and "receivers" to insert and remove the tool. These upgrades must also be performed to replace pipeline features that would obstruct the passage of the tool. 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 to identify pipeline anomalies that must be remediated through the Direct Examination and Repair process. In this process, 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 39 – Electro Magnetic Acoustic Transducer (EMAT) Tool After an Inspection on Line 400

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.

As of 2023, approximately 51 percent of the PG&E gas system is piggable. In 2023, PG&E inspected a total of 460.63 miles. 190.77 of those miles were assessed with ILI for the first time. Much of PG&E's pipeline was installed decades before ILI was invented. Today, about 29 percent of the PG&E system is not capable of supporting the running of traditional ILI tools, regardless of upgrades, 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.

In late 2023, PG&E initiated work to develop a training program at the Winters Gas Training Facility to train PG&E coworkers on the safe loading and unloading of cleaning and smart pigs, and the identification of abnormal operating conditions while running certain tools through the line. As part of the training program, a 600' long test loop made of 8" steel pipe, with a launcher and receiver, will be installed that utilizes compressed air to push cleaning pigs back and forth. Training is expected to be ready for rollout mid-2024.

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 unintended product such as water, solids, salts, etc. SCC is degradation of gas transmission pipe due to cracks induced from the combined influence of tensile stress[22] 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 40 – PG&E Employee Installing a Cathodic Protection Rectifier

As part of the new PHMSA regulations (Mega Rule Part 2) published in 2023, PG&E reviewed and revised standards, procedures, and training. This new regulation is focused on transmission pipeline restoration and mitigation timelines and expands requirements for AC and DC interference programs, as well as coating inspections of new pipelines. PG&E also participated in an Association for Material

Protection and Performance (AMPP) committee that published a guidance document to assist all operators with interpretation and implementation of corrosion control methodologies to align with the new PHMSA regulation.

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 CP to buried or submerged structures. CP mitigates corrosion through administering direct current through the soil 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 CP in conjunction with coatings provides additional protection for buried or submerged assets.

PG&E also monitors the level of CP on its assets and for conditions that may limit the ability to maintain adequate levels of CP on buried or submerged assets. Such conditions include contacted 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 included in Table 22.

Table 22 – 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 contacted cased crossings.
CP New, CP Replace, 850 Off	Designs, installs, and maintains CP systems to prevent corrosion. In addition, PG&E has implemented a more conservative CP criterion for its transmission piping system.
Close Interval Survey	Collects CP readings at approximate three-foot intervals on transmission piping to verify levels of CP between established monitoring points.
Corrosion Investigations	Investigates the cause of corrosion control deficiencies and/or corrosion damage and recommends mitigating solutions.
Enhanced CP Survey	Evaluates distribution piping CP area boundaries, monitoring locations, protection status, and updates documentation to ensure proper operation of CP systems.
Electrical Interference – AC	Evaluates and mitigates the threat of alternating current interference on gas piping systems.
Electrical Interference – DC	Evaluates and mitigates the threat of direct current interference on gas piping systems.
Internal Corrosion	Evaluates and mitigates the threat of Internal Corrosion in gas pipelines.
Routine Maintenance	Routine monitoring of corrosion control system effectiveness, to include rectifier inspections and maintenance; pipe-to-soil monitoring, casing-to-soil monitoring, and atmospheric corrosion inspections.
Test Stations	Installs or replaces test stations in areas along the piping system where CP monitoring is required.

PG&E continues to advance in 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. For 2023, PG&E continued to actively participate in corrosion research conducted by the Pipeline Research Council International (PRCI) and support efforts to incorporate the results of such research into corrosion control regulations and standards through its participation in the Association for Material Protection and Performance (formerly National Association of Corrosion Engineers (NACE) International and the Society for Protective Pipe Coatings), 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 seismic land movement at active earthquake faults that could adversely subject a natural gas transmission pipeline to external loads. 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 identify both anticipated geologic movement and pipeline mechanical properties in order to prioritize mitigations that will enhance the integrity of the pipe (Table 23) during a seismic event. Following each study, the mitigation work is then prioritized by considering the likelihood of failure, the probability that a seismic event will occur at the fault, and the consequences of failure, which includes the impact on the local population, PG&E system reliability, and the environment. Mitigation typically includes modified trench designs, trench adjustment, pipe replacement or realignment, or installation of automated isolation valves. In 2023, PG&E performed studies on 83 crossings and mitigated six crossings.

Table 23 – Earthquake Fault Crossing Program

	Studies[a]	Fit-for-Earthquake	Crossings Mitigated [b]	Crossings Replaced
Pre-2015	52	N/A	24	6
2015	65	14	18	4
2016	65	3	6	3
2017	22	5	7	2
2018	34	22	25	3
2019	12	6	12	6
2020	38	17	4	4
2021	8	0	2	2
2022	61	0	0	0
2023	83	22	6	2

(a) Studies are conducted to determine if a pipeline is Fit-For-Earthquake (FFE) per current design through geological pipe assessments.

(b) Crossings are considered mitigated if pipe meets or is designed, retrofitted, or replaced to satisfy the FFE criteria.

Figure 41 – L-301A Fault Crossing Pipe Replacement

j) LEAK SURVEY

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

PG&E outlines current requirements, standards, and guidelines for the LS and Detection Program in its procedures. In 2023, PG&E surveyed over 1.4 million gas distribution pipeline services, over 13,000 gas transmission pipeline miles, and performed daily leak surveys on 90 wells in compliance with CalGEM's emergency gas storage regulations. In addition, PG&E completed quarterly CARB LS at the 13 Gas Transmission Compressor/Storage Well Facilities, consisting of 150,598 individual components. PG&E also performed Daily LS of the three Storage Well facilities (Pleasant Creek, Los Medanos and McDonald Island) as part of the COGR (CARB Oil and Gas Rule) for all 365 days of the calendar year.

PG&E conducts three-year leak surveys consistent with Best Practice 15 in the Leak Abatement OIR D.17-06-015. PG&E will continue its expanded use of the Advanced Mobile Leak Detection technology for its gas distribution system targeting emissions as the main focus. The use of the Advanced Mobile Leak Detection technology and the acceleration of the LS 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; and (2) reduce GHG emissions.

In addition, in 2023, PG&E continued 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 7 scfh of methane. As a result, in 2023, PG&E completed the Super Emitter survey on 70 percent of its gas distribution services. The purpose of this survey is for Advanced Mobile Leak Detection to identify and measure the leak flow rates of Super Emitters as they are found. The data then informs PG&E of the prevalence of these leaks and emission reduction that can be gained by repairing them quickly.

In 2023, PG&E continued its journey to a paperless LS process with implementation on track for 2024. To maintain employee and public safety, PG&E uses drones with Open Path Spectrometry (OPS) leak detection units to survey our submerged transmission pipelines. This prevents some temporary road closures and reduces the number of surveys completed in navigable waterways with boats.

PG&E's LS and Atmospheric Corrosion (AC) inspection CGI process continues to be successful, seeing the backlog of open inspection CGIs lessen year over year down to the lowest levels since the program began in 2018. 2023 began with a backlog of 1,180 AC CGIs and 1,963 LS CGIs and ended with 864 and 951 respectively. During 2023, 33,664 AC CGIs and 35,589 LS CGIs were created. In 2023, PG&E continued to utilize the process designed in previous years and to implement several process improvement initiatives that increased the success rate of completing mandatory inspections. The process includes letters, postcards, text messages, emails, automated Interactive Voice Response phone calls, and personalized outbound calls from a team of Service Representatives in an attempt to gain access to our facilities. The text messages and emails include custom portal links to a PG&E site that allows customers to schedule their appointments in minutes right from their computer or smartphone.

Concurrently with the attempts to schedule appointments, gas compliance representatives attempt to complete inspections via canvassing attempts. PG&E continues to utilize electric service interruptions if customers do not agree to access after previous unsuccessful attempts. In 2023, an improved Salesforce product was rolled out that led to increased capacity by the service representative team. Additional internal reports were created, and existing reports were improved resulting in a higher level of visibility to the backlog of work. This led to an approximate 50 percent reduction in reported past due work in 2023 compared to 2022.

Summaries of PG&E's 2023 Leak Survey cycles for its distribution and transmission pipeline systems are shown in Table 24 below:

Table 24 – Leak Survey Cycles

Facility Types[a]	Description	Survey Frequency
Distribution	Business districts and public assemblies	Annually
	Buried metallic facilities not under CP and not covered by an annual requirement	3 Years
	All copper facilities	3 Years
	Balance of underground distribution facilities	5 Years
Transmission	Department of Transportation (DOT) transmission all odorized transmission (including non-HCA pipe within a Class III and Class IV location)	Semi-Annually
Un-Odorized DOT Transmission and Un-Odorized DOT Gathering	Class I, Class II, and Class III	Semi-Annually
	Class IV	Quarterly
Gathering (odorized)	Class I, Class II, Class III, and Class IV	Annually
Transmission Stations	Class I, Class II, and Class III	Semi-Annually
Electric Substations	Any existing facilities within 150 feet of the structure	Annually (PG&E Best Practice)

(a) Utility Procedure TD-4125P-10, "Identifying Gas Transmission Assets."

k) Leak Repair

Pipeline safety regulations and California state code require PG&E to repair certain leaks. In 2023, PG&E's trained and operator-personnel graded leaks 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 forth in GO 112-F. In addition to rechecking annually as required, PG&E repairs above-ground Grade 3 leaks on its distribution system within 36 months of discovery. In 2023, PG&E repaired 1,291 below-ground Grade 3 distribution leaks to further reduce GHG emissions.

In 2023, PG&E used its continuous improvement approach to more efficiently bundle and schedule leak repairs. Identifying all the work required in an area at one time provides the opportunity to bundle work locations and maximize use of resources. In 2023, PG&E repaired over 13,000 gradable leaks on the gas distribution and transmission system.

Figure 42 – PG&E's Maintenance & Construction Crew at Work

In 2023, PG&E also focused on improving Leak Repair effectiveness and efficiency by maintaining a level-loading approach, managing the average days open for gradable leaks rather than the inventory of Grade 2 leaks at the end of the year. PG&E set an internal target for average age of open Grade 2 leaks of less than 150 days and exceeded that goal with the average days open of 113 days for 2023.

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.

I) Overpressure Elimination Initiative

A pipeline that operates at a higher pressure 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 OP event. OP events have the potential to overstress pipelines and may lead to loss of containment. Large OP events (see Figure 43) pose significant safety and operational impacts to PG&E's gas system. A large OP event is defined as any verified pressure reading that exceeds the design limits set forth in the CFR –49 CFR 192.201. PG&E has 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; and distribution of information around associated OP risk factors through training and communication initiatives. PG&E installed SCADA points to increase system real-time visibility in the Gas Control Center (GCC), and Large Volume Customer primary regulation sets also received accelerated inspections.

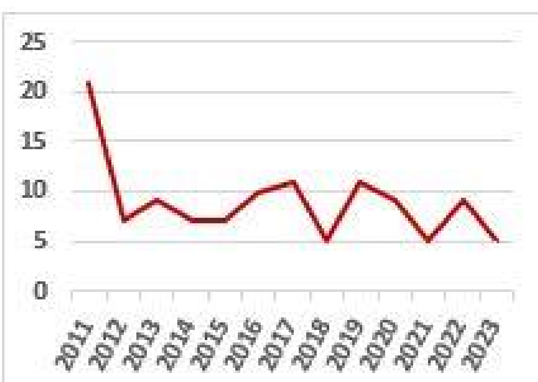


Figure 43 – Large Overpressure Events (2011 – 2023)

In 2018, PG&E started to install secondary overpressure protection devices on pilot-operated regulation equipment.[23] PG&E originally had a strategic goal of eliminating the common failure mode at 50 percent of our pilot-operated sites by the end of 2022, including both distribution and transmission stations. This objective was to have been met predominantly by the installation of secondary OP protection devices (slam shut devices). Pilot-operated regulation equipment is particularly vulnerable to large OP events for two reasons: (1) the equipment can fail due to gas quality issues, such as debris, sulfur, liquids, or black powder; and (2) the equipment tends to have a design that causes both the regulator and the monitor to fail in an open position (common failure mode), therefore resulting in a loss of regulation.

As the program has evolved over the past few years, it has become apparent that installing slam shut devices on transmission stations that serve large number of customers potentially creates a large outage risk. Thus, PG&E has adopted a strategy to evaluate each of the stations individually before determining whether a slam shut device is appropriate. The 2020 Protecting Our Infrastructure of Pipelines and Enhancing Safety Act now appears to require that the common failure mode on distribution district regulation be mitigated, so PG&E has prioritized retrofitting these stations. PG&E currently has 1,535 distribution pilot-operated regulation stations and 572 transmission pilot-operated stations. At the end of 2023, PG&E had a total of 939 distribution and 97 transmission (1,036 total) pilot-operated stations in which the common failure mode has been mitigated, which equates to 61.2 percent and 17.0 percent retrofit percentages respectively (49.2 percent of the total population).

Figure 44 – Photo Pointing to Slam Shut Installations

At the end of 2018, the 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, MOC 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 OP event is to augment code-required pressure control and OP protection devices (first layer) with a slam-shut (second layer) that will provide protection against an OP event. In addition, PG&E has developed controls to mitigate the risk of damage to a sensing line resulting in an OP event. Work is on-going to explore additional controls and mitigations in this area. OP 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 assets and operations against all possible modes of failure.

In 2019, the first annual version of the Long-Term Overpressure Elimination Roadmap was published. This comprehensive document describes in detail past, current, and proposed future activities related to OP elimination. The second iteration of the plan was published in July 2020; the third iteration was published in July 2021; the fourth iteration was published in July 2022, and the fifth iteration was published in November 2023. The Roadmap is updated annually, with the next iteration scheduled to be published during the summer of 2024.

In 2023, PG&E recorded five large OP events, which is at the bottom of the historical range of 5 to 11 large OP events per year since 2012. In 2023, PG&E recorded a total of 17 large and small OP events, which is the lowest number total OP events since the events were first tracked in 2011. Key points of emphasis to continue during driving down this number going forward includes: (1) the continuation of our strategy of installing secondary overpressure protection devices on pilot-operated regulation equipment; (2) the continued emphasis on human performance development and training; and (3) continuing to add additional rigor around the clearance development and execution process. We did not receive funding for any of the OPE mitigation programs in our 2023 General Rate Case Final Decision, and we anticipate that our rate of progress for many of these programs may slow significantly in the upcoming years.

PG&E continues to review operations and look for opportunities to perform work to further limit potential MAOP exceedances. Each activity builds on the goal to eliminate large OP events, thereby contributing to system safety.

m) Community Pipeline Safety Initiative

OVERALL PROGRAM METRICS (2013-2023)							
STRUCTURE MILES | >99% ADDRESSED				VEGETATION MILES | >99% ADDRESSED			
YEAR	MILES	PERCENT	COMPLETE	YEAR	MILES	PERCENT	COMPLETE
2013	5.00	1%	5.00	2013	115.00	7%	115.00
2014	110.00	32%	110.00	2014	146.00	17%	146.00
2015	93.00	58%	93.00	2015	380.00	41%	380.00
2016	114.00	89%	114.00	2016	540.00	76%	540.00
2017	30.00	98%	30.00	2017	258.00	93%	258.00
2018	7.60	99%	7.60	2018	86.60	98%	86.60
2019	0.25	99%	0.25	2019	18.03	99%	18.03
2020	0.00	99%	0.00	2020	0.26	99%	0.26
2021	0.0191	99%	0.0191	2021	0.91	99%	0.91
2022	0.00	99%	0.00	2022	1.81	99%	1.81
2023	0.066	99%	0.066	2023	0.00	99%	0.00
TOTAL	359.94	-	359.94	TOTAL	1,546.61	-	1,546.61

Figure 45 – Structure and Vegetation Miles Addressed (2013 – 2023)

PG&E's Community Pipeline Safety Initiative (CPSI) is a shareholder-funded program that focuses on enhancing the safety of the gas transmission pipeline by addressing items located too close to the pipe and pose a safety and/or emergency access concern. When items such as structures and trees are located too close to the pipeline, they can delay critical access for safety crews and potentially cause damage to the pipe.

Program-to-date, PG&E has addressed more than 99.9 percent of the identified safety concerns. This includes completing approximately 1,546 vegetation miles and 359.9 structure miles. The remaining work is primarily located in Lafayette, Palo Alto, San Jose District 6, and Santa Cruz County, with a few one-off projects in other locations. The cross-functional team is actively working with these jurisdictions and private property owners to complete all remaining work.

n) Gas Transmission Vegetation Management

PG&E's Gas Transmission Vegetation Management (GTVM) Program regularly inspects the area above and around the pipe to look for any new structures or trees/brush that are located within 14 feet of the pipeline and could pose a safety concern. We also review trees previously left in place as part of CPSI to determine if any conditions have changed.

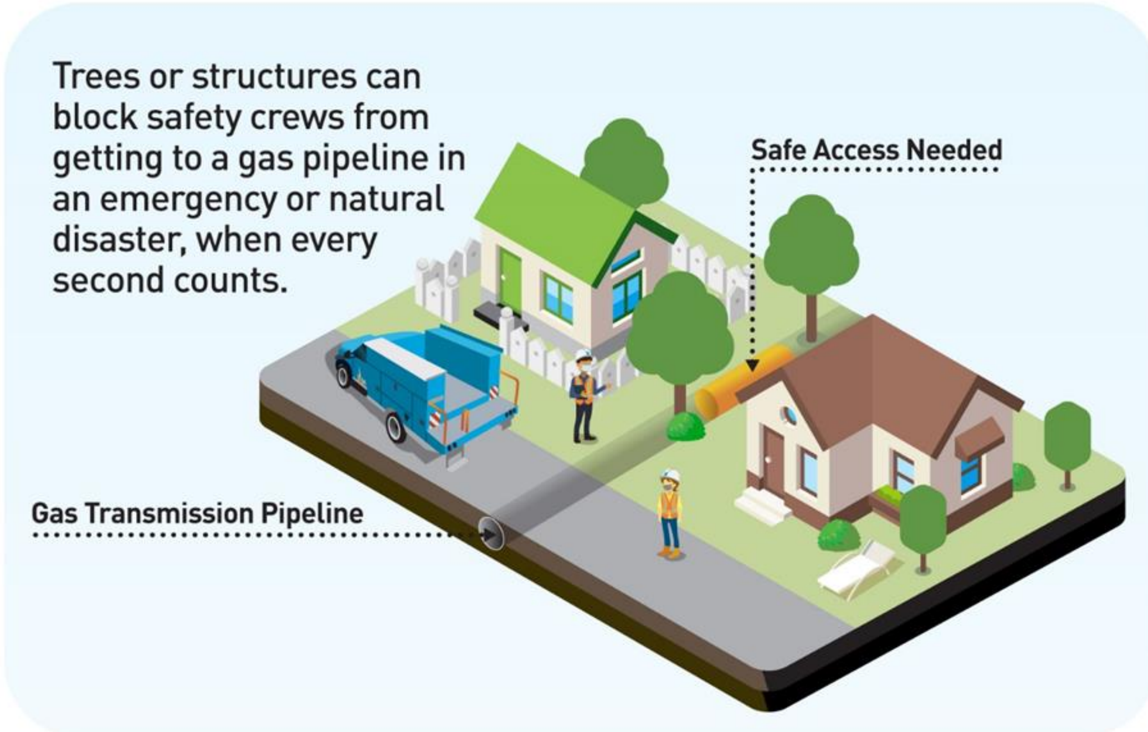


Figure 46 – Example of a Trees/Brush Inspection Site

PG&E inspected 2,300 miles of the gas transmission pipeline in 2023. Any trees that are identified as too close to the pipeline are reviewed further to determine if they need to be removed for safety. Each year, PG&E reviews the trees identified as potential safety concerns and prioritizes removals based on the risk posed to the pipeline and the community.

In 2023, crews inspected the area above the 2,300 miles of gas transmission pipeline and addressed 10 miles of vegetation that posed a safety risk and remediated 230 trees.

Before removing a tree, PG&E shares information with the property owner and provides an opportunity to the owner to remove or relocate the identified vegetation themselves. If an owner does not want to self-perform the work, PG&E will remove the vegetation at no cost to the owner. PG&E also works directly with property owners to remove or relocate the structures identified as a safety concern. This work is performed at the property owner's expense.

We know we cannot do this work alone. In addition to the work mentioned above, PG&E also shares educational information on the importance of keeping the area above the pipeline safe and clear with local governments, first responders, and customers. This outreach includes mailers, meetings/presentations, email communications, social media, a dedicated webpage, and more.

Through these outreach efforts, we are increasing awareness on safe planting practices near a pipeline and promoting shared responsibility among our customers to keep the area safe. This is leading to fewer new trees being planted in unsafe locations. By working together, PG&E and the community can reduce safety risks and prevent accidents and damage to the pipeline.

6. Mitigating the Risk of Loss of Supply

The risk of loss of gas supply poses significant public health and safety risks. Customers depend on their gas service for various energy needs including space heating, water heating, and cooking. In very cold weather, loss of space heating can itself be life-threatening in addition to prompting customers to use unsafe heating alternatives.[24] Loss of gas service can also lead to extinguished gas pilots and the subsequent potential for non-combusted gas to enter affected buildings. In some scenarios, insufficient local pipeline capacity could result in loss of gas service to electric generation customers, which also introduces health and safety concerns. PG&E mitigates these risks by designing and operating its gas system to maintain adequate system capacity to supply forecasted demand.

In 2023, PG&E transported and delivered about 1.016 trillion cubic feet of gas, a 5.9 percent increase from the previous year.[25] To meet this demand, 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 Capacity Design Criteria

PG&E's gas systems are designed to meet all expected core demands (residential and small commercial customers) with noncore demand (such as large commercial or industrial customers) assumed fully curtailed at a design temperature that is the coldest temperature that may be exceeded once in every 90 years, on average (referred to as an Abnormal Peak Day, or APD). PG&E's gas systems are also designed to meet all expected core and noncore demand at the coldest temperature that may be exceeded once in every two years, on average (referred to as a Cold Winter Day, or CWD).

Table 25 – PG&E Gas System Capacity Design Criteria

Design Temperature Average Recurrence Interval	Design Condition
One in 90 years, APD	Meet all expected core customer demand, with noncore demand assumed fully curtailed.
One in 2 years, CWD	Meet all expected core and noncore customer demand.

In addition to noncore curtailments, temporary manual operations can be implemented to increase available capacity on the gas system or shift flow to alleviate system constraints [see Section IV.2.c *Transmission Pipe* for Strategic Objective on meeting system capacity]. These operations are assumed to be in place when designing the system for capacity.

PG&E develops its capacity plans with the use of hydraulic simulation software to model its gas system. These models calculate expected pressures and flows throughout the system based on historical SmartMeter customer demand data trends. An annual model maintenance process ensures hydraulic models accurately reflect the physical and operational characteristics of the gas system. The process includes calibration and documentation components. Hydraulic models are accompanied by numerous analytical tools, processes, standards, internal and external data, and training and development to ensure personnel are properly equipped to implement the necessary measures for mitigating the risk of loss of gas supply.

b) Inventory Management

Inventory management is a critical service provided by Gas Operations to deliver safe and reliable gas to its customers. PG&E's pipeline inventory constantly changes due to the dynamic inflows and outflows of the system (Figure 47) so it is critical to keep inventory in balance. If inventory is too high, maximum pressures in the pipeline are approached and compressors can shut down. If inventory is too low, there is inadequate pressure to serve PG&E's customers.

Gas Operations utilizes several operational tools to maintain balance in pipeline system inventory. PG&E's Gas Storage provides withdrawal and injection services for Pipeline Balancing and Reserve Capacity. Operational Flow Orders and Emergency Flow Orders are gas marketing tools to financially incentivize customers to help keep the system in balance.

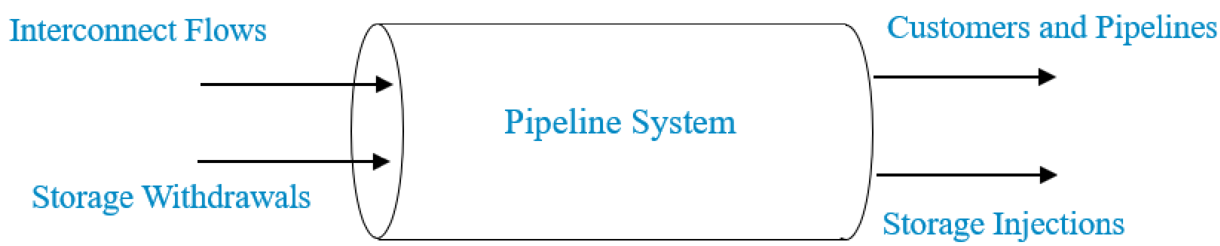


Figure 47 – Example of Pipeline System Inflows and Outflows

c) WINTER OPERATIONS

In addition to designing and building its gas system to meet forecasted customer demand, PG&E prepares a detailed operation and curtailment plan prior to each winter. These plans outline the planned response to forecasted cold weather conditions to ensure the system maintains reliable gas service and follows its capacity design standards. PG&E continuously monitors the pressure of its system and responds to any SCADA alarms that activate if system pressures fall to a level that is lower than what is expected [see Section IV.7.a *Gas System Operations and Control*]. Winter operating plans and long-term capacity plans are adjusted, as needed, based on actual system performance.

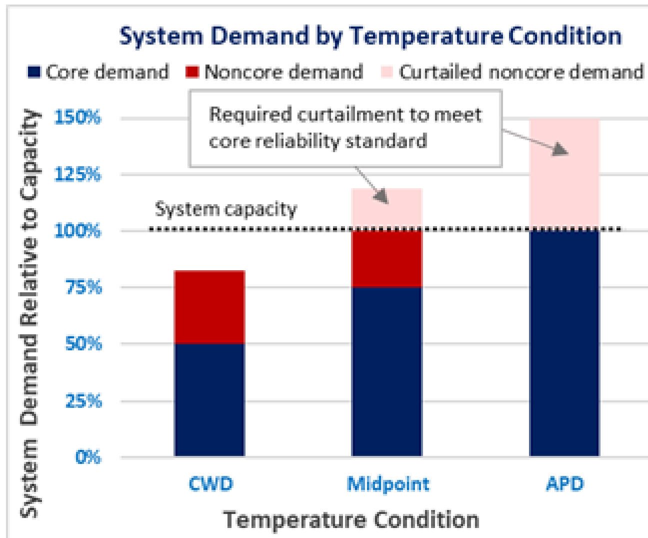


Figure 48 – Conceptual Representation of a Non-core Curtailment Plan

d) OPERATIONS FOR FACILITATING SAFETY WORK

In some cases, the measures necessary to mitigate risk require temporarily changing the configuration of the gas system. For example, conducting a strength test requires taking a pipeline out of service. If pipeline anomalies are discovered through in-line inspection, the operating pressure of a system may need to be reduced until the anomalies can be further examined and repaired.

Safety work is scheduled such that adequate supply to customers is maintained, as practical. If adequate supply is unavailable, other techniques are utilized such as portable LNG, CNG, or compression. If necessary, planned service outages may need to occur, but are coordinated with customers. Any operations necessary to maintain sufficient capacity in the system are documented in a clearance procedure [see Section IV.7.b *Operations Clearance Procedure*]. Clearance procedures also include

SCADA alarm adjustments and pressure gauge monitoring requirements to ensure safe operation of the gas system.

Since 2021, guidelines for traditional in-line inspections have been in place that require the consideration of contingency plans to mitigate the risk of supply interruptions in the low probability event that an inspection tool becomes stuck in the line and restricts supply to the downstream system. If the risk cannot be fully mitigated, an emergency curtailment plan is developed and undergoes leadership approval in advance of the inspection.

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 the risk of 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 human-caused emergencies such as fires, floods, storms, earthquakes, cyber disruptions, and terrorist incidents;
- Respond rapidly and effectively, consistent with the National Incident Management System and State Emergency 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.

PG&E uses the structure of the Incident Command System to complete key steps in responding to incidents. The key incident response objectives in Table 26 represent a typical process flow through the cycle of an incident.

Table 26 – Key Incident Response Objectives

Objective	Description
Pre-incident Readiness	Proactive actions taken to prepare for a potential incident.
Make Safe and 9-1-1 Standby	Make area safe for public, employees, and responders.
Establish Command	Gather information about emergency, assess the situation in coordination with law enforcement and fire agencies, PG&E GCC, assign resources and establish the Incident Command Post (ICP).
Notify	Communicate to/notify the appropriate PG&E personnel, regulatory agencies, public agencies, city, and county emergency operations, GCC, customers and media.
Assess Damage	Identify potential public and PG&E infrastructure threats or at risk and determine need for isolation strategies.
Restore	Prioritize restoration efforts and restore gas service.
Demobilization	Deactivate ICP and/or Emergency Centers and return to business as usual.

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.

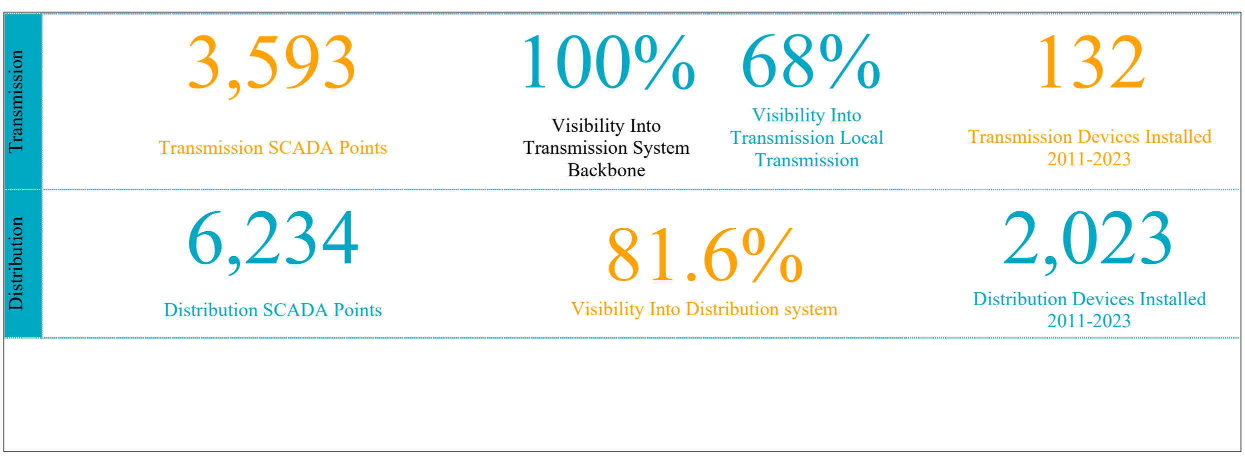


Figure 49 – PG&E's Progress in Enhancing System Visibility Through SCADA

Figure 50 – 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.

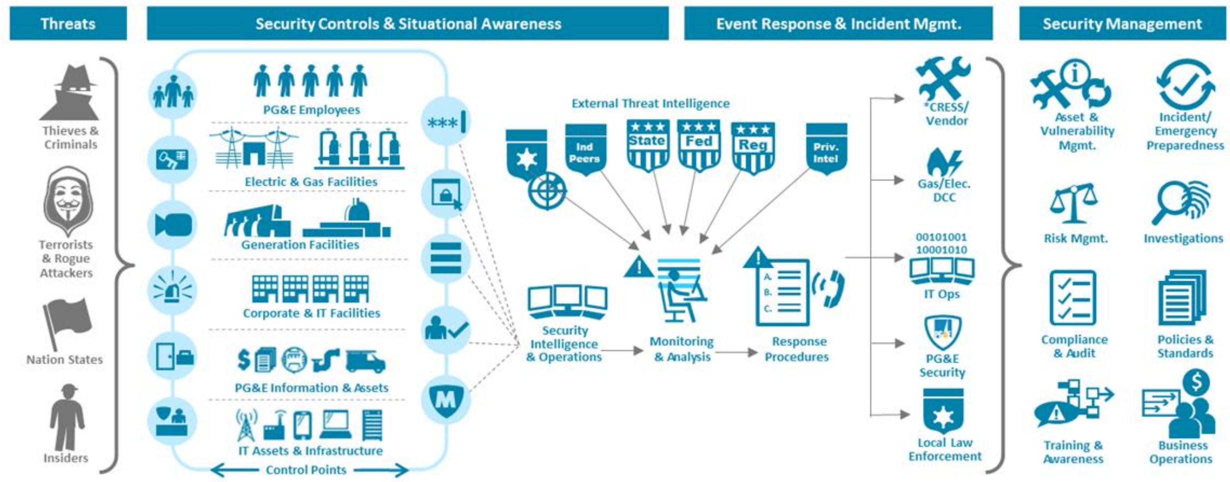
b) Operations Clearance Procedure

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. In 2023 the gas functional area identified clearance as a distinct process.

c) Security

PG&E's commitment to security directly contributes to our mission to deliver safe, reliable, affordable, and clean energy. PG&E's Security Program, which includes both cyber and physical security, effectively manages security risks and proactively adapts to evolving threats and changing business needs. The Security Program, based on industry best practices, is designed to enable risk-informed decision-making necessary to support PG&E's mission. Protecting PG&E from the ever-changing cybersecurity and physical security threat landscape enables us to conduct our work in a secure manner that protects our customers, employees, and assets. PG&E Security program’s mission is to deliver and maintain an integrated program to safeguard PG&E digital assets, people, facilities, and data by:

1. Identifying risks and defining mitigating strategies;
2. Building, deploying, and operating effective security technologies and processes;
3. Proactively monitoring for and responding to security threats; and,
4. Collaborating with public, private, local, state, and federal entities to drive standards and best practices.



Note: CRESS is Corporate Real Estate Strategy and Service

Figure 51 – PG&E Unified Cyber/Physical Security Program Effectively Manages Risk and Proactively Adapts to Evolving Threats and Changing Business Needs

PG&E's Enterprise Protection Fusion Center team tracks emerging and evolving activity that may pose a threat to the well-being of PG&E's employees, customers, and business enterprise. The Fusion Center provides a centralized, converged approach to correlate and analyze information from varied internal and external sources, both physical and cyber, into a coordinated view and response. This approach aims to deliver a timely and accurate characterization of any incidents and thereby enable a coordinated response. Identified threats are then mitigated at the appropriate levels.

PG&E's Threat Intelligence team tracks evolving cybersecurity and physical security threats. Trends include a growing prevalence and sophistication of ransomware, destructive malware, and the growth of file-less malware on endpoints. Additionally, supply chain exploits continue to grow in sophistication and prevalence.

PG&E's Security Awareness and Training Program is an enterprise security strategy focused on maintaining and strengthening the security culture at PG&E. Regular security communications educate employees on how to keep the Company's people, assets, and information secure. The PG&E Security Awareness and Training Program communicates and trains on security standards, best practices, tips, and risks, and helps employees understand the importance of protecting the people, information, and assets at PG&E. The Security Awareness and Training Program establishes employee engagement themes based on security assessments and threat intelligence information and ultimately reduces security risk.

Figure 52 – Examples of Active PG&E Government Partners

PG&E’s natural gas operations incorporate significant risk management activities, including those that address cyber and physical attack threats. PG&E’s Cybersecurity organization advises Gas on cybersecurity risk 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 higher levels of protection through security controls and mitigation improvements. Security controls and mitigation investments are reviewed and updated on an annual basis. PG&E has been working closely with U.S. Department of Homeland Security’s (DHS) Transportation Security Administration (TSA) in response to the TSA’s evolving Security Directives, initially issued in 2021, which require assessment and implementation of security measures. PG&E’s Enterprise TSA Compliance has been leading and working cross functionally regarding the Company’s response to TSA’s Cybersecurity Directives, which were put in place after the 2021 Colonial Pipeline ransomware attack. In May 2023, TSA came on site to perform a review of PG&E’s response to its Security Directives and found no issues. PG&E also submitted its first Compliance Assessment Program to TSA, which is how PG&E assesses its effectiveness in meeting the Cybersecurity Directives.

PG&E’s Corporate Security organization advises Gas on physical security risk mitigation and mitigation activities to physically protect functional area identified operational assets and cyber systems/assets from attacks through physical means. Corporate Security provides protection for all physical sites, while providing focused talent and processes for key critical infrastructure sites identified by the functional unit or DHS TSA Critical.

Given continual security 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 and improvements can occur through participation in security events, such as site-specific tabletop exercises, regular member participation with the American Gas Association (AGA), the Downstream Natural Gas Information Sharing and Analysis Center (DNG ISAC), and TSA calls and briefings and exercises. It is through the results of security exercises that PG&E is better able to identify and plan control improvements that strengthen Gas Safety. PG&E has worked closely with TSA in aligning with the Security Directive Pipeline-2021-02D. PG&E planned and executed the GridEx exercise VIII in November of 2023.

d) 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. This is further supported by PG&E's control room personnel training to develop a "bias for action." This training helps them recognize and act on system conditions warranting immediate isolation of pipeline systems. Planned SCADA installations are ongoing to increase system visibility [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. Since starting in 2011, a total of 405 valve automations have been installed. In 2023, two valves were automated through the Valve Automation Program.

e) 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).

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 sound, 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.

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 2.

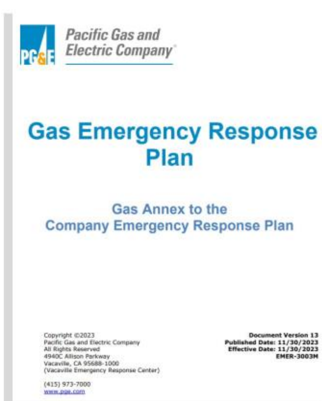
The CERP provides a broad outline of PG&E's organizational structure and describes the activities undertaken in response to emergency situations. The CERP presents a response structure with clear roles and responsibilities and identifies coordination efforts with outside organizations (government, media, 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[26] 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 functional area emergency response plans, which are annexes to the CERP. For 2023 changes to PG&E's GERP, please see Attachment 2.


Pacific Gas and Electric Company

Gas Emergency Response Plan

Gas Annex to the Company Emergency Response Plan

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EMER-3003M

Figure 53 – The Gas Emergency Response Plan as of November 30, 2023

The GERP provides an outline of the Gas 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 incident classification system shown in the figure below:

Figure 54 – PG&E's Gas Incident Classification Levels

iv. Gas Emergency Response Team

The Gas Emergency Response Team assists Gas with emergency planning, preparedness, response, and review. This group provides SME review of the GERP, supports 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 response structure and deployment, and the Gas Emergency Center. The GEC is activated according to criteria outlined in PG&E's GERP.

Figure 55 – Throughout 2023, the Gas Emergency Response Group:

Delivered IMT (Incident Management Team), GEC (Gas Emergency Team), and EOC (Emergency Operation Center) team ICS (Incident Command System) 300/400 training.

Facilitated 3 Well Control exercises and provided support for 17 Gas Operations Live Action Drills by establishing an incident command structure.

Supported the response to 4 emergency activations impacting Gas Operations.

Frequent outreach to first responders helps strengthen how PG&E coordinates when emergencies happen. In 2023, Public Safety Emergency Preparedness completed the following efforts in partnership and close coordination with first responders and local governments:

Figure 56 – Live Action Drill

Pacific Gas and Electric Company

Gas IMT Incident Action Plan
Novato Pipeline L-21G and 21-F
Operational Period #: 4
3/26/23 0600 to 3/27/23 0600

Figure 57 – Region 1 North Coast IMT Incident Action Plan Cover

Figure 58 – Novato Landslide Affecting lines 21-G & F

Figure 59 – Disaster Recovery Drill at Topock Compression Station Emergency

Figure 60 – Region 3 Bay IMT Seminar/Tabletop Exercise

V. WORKFORCE

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. Well-trained, fully-engaged employees are a key component of Gas Safety Excellence.

For example, employees are required to wear 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 certain tasks. 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. PG&E's PPE Matrix and JSSA are vital resources for employees as they plan their work prior to executing in the field.

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 engages the Workforce Planning function 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 that 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 2023, PG&E continued to use projects designed to improve employee safety. The focus was on taking care of employees before an injury gets worse. The following summarizes the proactive measures taken by Gas in 2023 and their progress and successes:

RSI Guard – Gas activated the RSI Guard software on employee computers and enabled set break/microbreak frequency to promote breaks, stretches and microbreak awareness to perform computer work in a healthy and safe way. Gas performed at 97 percent overall break compliance in 2023, exceeding the goal of 85 percent compliance. It has been recommended that we no longer track break compliance as it is not correlated with injuries and does not ensure that those with higher break compliance are any less likely to develop an injury than those that are less compliant.

Nurse Care Line (NCL) – If an employee feels any pain or illness, they are encouraged to call the NCL for medical advice which can reduce the severity of an injury, if treated early. Nurse Care Line timely reporting has increased significantly between 2014 and 2023. In 2023, there was a slight decrease in reporting of injuries within the first day; however, reporting within 24 hours of the onset of discomfort remains above 90 percent (as seen below).

Table 27 – Gas - NCL Timely Reporting

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Percentage Total	64.3%	63.1%	69.5%	74.0%	77.7%	80.8%	75.5%	75.9%	92.8%	90.7%

The focus on early reporting and prevention has contributed significantly to the downward trend of injury severity and reduction in average cost per claim. We anticipate this downward injury trend will continue with increased timely reporting, IAS utilization, Industrial Ergonomic evaluations, and Health and Wellness programs.

IAS Utilization – In 2023, 38 percent of Gas eligible physical workforce participated in 1-1 services with an IAS. Overall, the Industrial Athlete program hosted over 12,000 group events with over 130,000 participants company-wide with approximately 66% of those participants coming from Gas Operations.

Industrial Ergonomics – Increased assessment of individual tasks by both Industrial Ergonomists and Field Safety Specialists. Industrial ergonomic projects in 2023 included:

- Meter Jack project for GSRs: Identified tool to reduce strain to hand/arm/shoulder when installing/uninstalling heavier meters resulting in approximate 43 percent risk reduction.

- Quick Change tank transport project for GSRs: Alternate quick change tank carrier with wheels prototype piloted; until prototype can be manufactured, using cart or wagon to transport QCT resulting in approximate 53 percent risk reduction.
- Comparative Analysis of tools/methods to remove stuck collars for GSRs: Consider use of Sawzall to remove stuck collars resulting in approximate 58 percent risk reduction.
- Muscle Fatigue Failure Analysis for GSRs: Review of GSR jobs looking at ergo risk factors to shoulder, back, and distal upper extremities. Findings indicated that muscle fatigue at shoulders reaches maximum daily, due to setup/prep activities (carrying tool bag, equipment, load/unload vehicle etc.) as well as activities requiring high applied forces (i.e. stuck meter collar).

3. Workforce Training

PG&E's Gas Safety Academy in Winters, California, is a state-of-the art gas training facility that opened in August 2017. The facility includes a utility village, which provides realistic residential and commercial scenarios for LS, leak pinpointing, and emergency response. Other features include the Miller® LiveArc™ welding performance management system with a simulation/pre-weld setup mode and live-arc training mode allowing learners the opportunity to fine-tune their foundational welding skills, build confidence, become familiar with body mechanics, and build muscle memory prior to welding.

At the Gas Safety Academy, fundamental safety and code requirements are embedded within every course. Safety is non-negotiable and our standards align with the requirements of federal OSHA, Cal/OSHA, National Commission for Certification of Crane Operators, NACE, American Weld Society, and the California Department of Motor Vehicles.

In 2023, the Gas Safety Academy facilitated over 18,000 student days at the technical, apprentice, and leadership levels. As of December 31, 2023, PG&E has developed or enhanced approximately 1,300, courses since 2012 (Table 28). PG&E continues to enhance and continuously improve the training so that all classifications in Gas have initial and refresher training.

Table 28 – PG&E Number of Courses Developed or Enhanced from 2012 through 2023	
2023	48
2022	47
2021	118
2020	224
2019	112
2018	122
2017	162
2016	214
2015	107
2014	78
2013	88
2012	14
Total	1,334
*Total does not represent total number of active courses	

Workforce safety highlights from 2023 include:

- Completed the engineering design and began construction on a 700-foot pigging test loop in the Winters Training facility. The test loop and associated training scenarios are designed to place students in actual Gas Operations pigging situations encountered in the field and includes loading, unloading, pipe pressurization and manipulation of the systems twin-lock door mechanisms.

Identifying and responding to abnormal operating conditions (AOC's) are also part of the training strategy.

- The Winters training facility added 18 new residential meter set outlets pressurized with air, allowing for additional student throughput. Using air versus natural gas fed meters allows for safe practice and eliminates methane emissions that may occur during purging.
- Designed, established, and implemented the Safe Access field to support the Compliance Department's Locate and Mark Training. Using an integrated holistic approach, this has enabled employees to safety locate electric facilities.

The Gas Safety Academy continues to improve technologies used to facilitate learning, including Mobile MyLearning, which was expanded to more courses. The expansion gives learners the ability to complete safety and compliance training on company smart devices without needing to travel to a headquarters. Mobile MyLearning provides the opportunity for on-demand training and immediate content updates in the field.

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 29 are the output of a partnership between Gas SMEs and PG&E Academy. The partnership starts with Gas Training Governance and is led by leaders within Gas to ensure that PG&E Academy's projects are aligned to key initiatives within the functional areas they support. High-risk, high-consequence tasks are identified by utilizing SME expertise to ensure that the training mirrors actual field conditions and scenarios. The Training Governance charter outlines the partnership with a mission to provide oversight, control, decision making, and coordination of policies, procedures, and processes that successfully support PG&E Gas' strategic objectives to deliver to our hometowns, serve our planet, and lead with love.

Table 29 – Gas Training Recommendations 2012-2023	
2012 Recommendation	**Progress as of Dec 31, 2023**
Develop programs that support employees throughout their career	• Courses developed and aligned to business need and results are measurable. • Completed and enhanced apprentice and new employee programs developed to advance employees to journey-level competency. • Increased focus on refresher training to maintain skill and competence of existing workforce.
Broaden technology solutions and leverage external curriculum	• Deployment of mobile web-based training solutions available on iPad and iPhone. • Performance support solutions available via portal platform and SharePoint for most functional areas in Gas Ops.
Implement continuous training improvement processes	• Gas Training Governance continues to mature and the recently established Gas Training Alignment Committee has provided an open forum for Gas Operations to introduce and discuss potential training needs and performance gaps. The Academy partnered with the Gas functional area and the Gas Qualifications department to develop technical training and qualification profiles for Gas employees to ensure consistency amongst job classifications and to provide line of sight into who is trained and qualified to perform the work. • Training materials archived and verified supporting records management initiative.

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. In 2023, the teams qualified over 25,000 qualifications for PG&E employees and over 6,000 qualifications for contractors.

Figure 61 – Employees Taking Performance 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 80 percent on written exams and 100 percent on performance exams to be "qualified." Evaluations are primarily geared towards safety and recognizing and addressing Abnormal Operating Conditions (AOC). Depending on the task and applicable regulations, qualifications must be renewed every six months, one year, three years, or five years.

Personnel use task specific Span-of-Control practices to gain hands-on experience working under the direction and observation of qualified individuals. Working under the direction and observation of qualified persons allows trainees to practice their skills in real-world conditions and gives qualified persons 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 can 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 continued the program implemented in 2020 to ensure process consistency with an approved contract evaluator and proctors. The program includes regular visits by a PG&E Operator Qualification (OQ) representative to the approved contract evaluators' and/or proctors' locations to conduct observations of their OQ process during live OQ evaluations. This helps to ensure that our approved contract evaluators' programs are consistent with PG&E's internal OQ program and can help us provide feedback or opportunities for improvement where necessary. The Gas Qualification department continues to refine the process every year.

In 2023, the Gas Qualification team launched a pilot project to explore converting certain qualification exams into Virtual Reality format. This initiative seeks to leverage cutting-edge technology to potentially minimize safety risks by reducing the necessity for travel, to enhance performance visibility, and to create avenues for continuous improvement, ultimately improving compliance statistics for PG&E.

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.

5. Contractor Safety and Oversight

Contractors are an important aspect of PG&E's technical workforce. Since contractors often work with PG&E 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. 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. The Contractor Oversight Procedures follow a four-step process (Figure 62) for contractor safety and oversight. Other revisions included updates to various responsibilities (Competent Site Representatives and Project Team),

Figure 62 – Four-Step Process to Contractor Safety and Oversight

enhanced the contractor safety observation criteria, and added requirements for a PG&E Safety Representative.

Prior to starting a job, PG&E pre-qualifies contractors and subcontractors and confirms they are qualified to complete contracted work through internal and International Suppliers Network (ISN) reviews. PG&E continues to improve its contractor pre-qualification process and to update it to meet and exceed corporate requirements. 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 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, analyzing both quantitative and qualitative trends in data from on-site observations and inspections.

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.

Contractor performance is tracked throughout the year and compared to Company performance. Figures 63 and 64 provide 2023 metrics on injuries and motor vehicle incidents comparing PG&E internal data and data provided by Strategic Partners.

Safety Trend Rates							
OSHA				LWD			
All Parties	T&D Operations	T&D Construction	Strategic Partners	All Parties	T&D Operations	T&D Construction	Strategic Partners
2023 Cumulative YTD				2023 Cumulative YTD			
1.56	3.49	0.96	0.43	0.31	0.75	0.20	N/A
Gas Operations EOY OSHA Target: N/A				Gas Operations EOY LWD Target: N/A			
2022 EOY				2022 EOY			
2.10	4.22	1.83	0.42	0.42	1.06	0.24	N/A

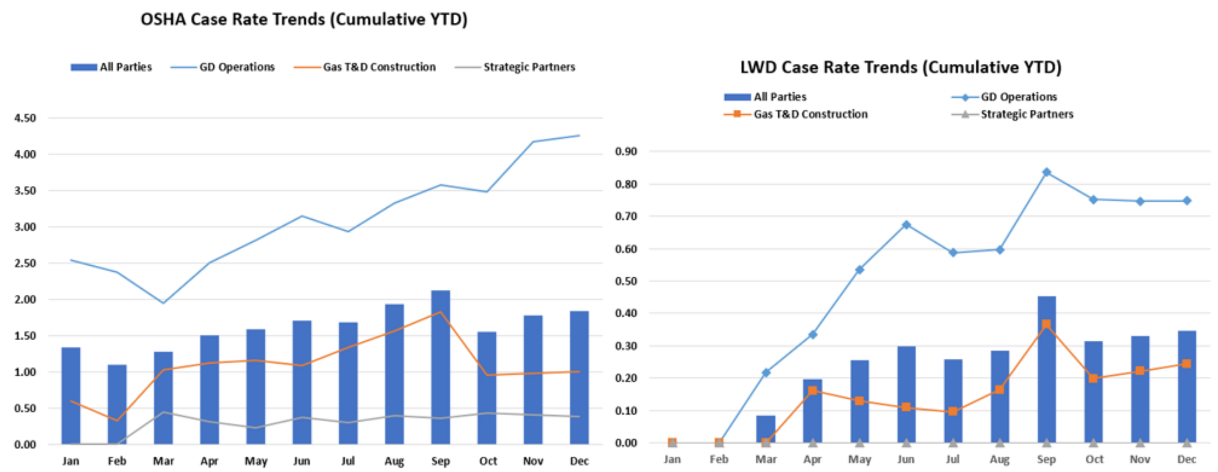

Figure 63 – 2023 Gas Safety Performance | OSHA and Lost Work Days (PG&E vs Strategic Partners)

Safety Trend Rates							
PMVI				SPMVI			
All Parties	T&D Operations	T&D Construction	Strategic Partners	All Parties	T&D Operations	T&D Construction	Strategic Partners
2023 Cumulative YTD				2023 Cumulative YTD			
1.49	2.71	2.17	0.36	0.12	0.23	0.22	0.00
Gas Operations EOY PMVI Target: N/A				Gas Operations EOY SPMVI Target: N/A			
2022 EOY				2022 EOY			
1.53	2.59	1.93	0.69	0.15	0.30	0.25	0.00

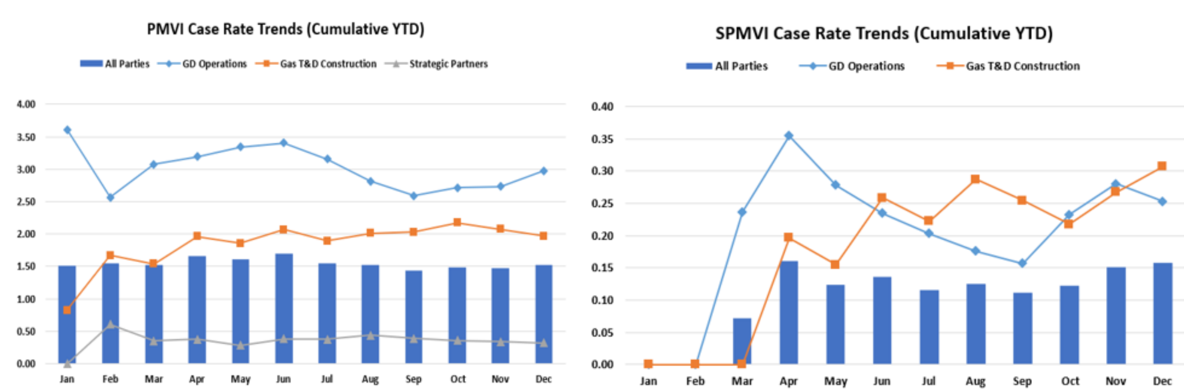

Figure 64 – Preventable Motor Vehicle Incidents and Serious Preventable Motor Vehicle Incidents (PG&E vs Strategic Partners)

In 2023, the Gas Contractor Safety Team and the Gas Contract Owners continued to focus heavily on improving contractor incident reporting, tracking, and follow up. There was also a notable expansion of Strategic Partners and the number of contract companies that reported their data in comparison to previous years. The incident reporting improvements in the Contractor Incident Program showed a substantial increase in reporting of First Aids, OSHA, PMVI, Good Catches, Dig-In and Property Damage. As a result of the improvements in the Contractor Incident Program, there were count and rate increases in comparison to previous years. Looking into 2024, Gas Contractor Safety expects to continue to see rigorous and expanded reporting by our Contract partners. Contract partners began leading their own SIF investigations with support from functional areas and the Enterprise EH&S Cause Evaluation Teams. This improvement in SIF Investigations has translated to increased ownership and self-identified corrective actions. Gas implemented an improved Project Specific Safety Plan and Programmatic Safety Plan for Medium and High-Risk Gas Contractors. This expanded contractor engagement resulted in increased hazard identification and rigorous pre-job planning.

As PG&E strives to improve project safety, quality and productivity, the Company takes every opportunity to acknowledge when people are 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 2023, there were 1,500 "Good Catches" turned in to PG&E's safety and construction management function. This is a 7 percent increase compared to 2022. 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. This increase is attributed to improved reporting tools that allow field employees to report good catches directly to Gas Contractor Safety.

6. Partnership With Labor Unions

Union-represented employees make up almost 79 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 2023, PG&E continued to collaborate with union leadership leading to improvements, such as:

- Engaging with union business representatives on critical topics at Coworker Town Halls (ELTs);
- Collaborate further to address and mitigate employee escalations and concerns;
- Launching human performance tools throughout the organization;
- Re-launching the Energy Hazard Wheel; and,
- Continue supporting the 100/100 initiative to support Distribution, Damage Prevention and Construction.

VI. Compliance Framework

PG&E transports and stores natural gas under the requirements of state and federal safety regulations. The Ethics and Compliance Maturity Model was developed in 2016, and the model is derived from the Federal Sentencing Guidelines and the U.S. Department of Justice's Evaluation of Corporate Compliance Programs, both of which define the parameters of an effective ethics and compliance program. PG&E continues its focus that each functional area achieves Level 3 maturity in each of the following eight Maturity Model elements:

1. Risk Assessment;
2. Program Governance and Resources;
3. Guidance Documents;
4. Compliance Controls;
5. Communications and Training;
6. Monitoring and Auditing;
7. Investigation and Response; and,
8. Enforcement and Incentives.

The maturity level ratings between 1 and 5 are defined as:

1. Initial;
2. Defined and Built;
3. Implemented;
4. Managed; and,
5. Optimized.

The Compliance Maturity Model is a framework to manage the overall compliance program, and it provides Gas a guideline on what an effective ethics and compliance program should look like. This approach aligns with the "Plan, Do, Check, Act" (PDCA) management method that PG&E employs throughout its operations as part of Gas Safety Excellence.

Gas has made significant progress since the initial baseline performance assessment was conducted in 2019 and has improved maturity scores in seven of the eight elements. The last maturity assessment was completed by Gas, in partnership with Ethics & Compliance, in 2021. The 2021 assessment results were finalized in early 2022, and six of the eight Compliance Maturity Model elements achieved level 3 maturity scores. Element 4 – Compliance Controls remained at level 1, which was expected as the Controls Program is expected to reach level 3 maturity in 2026. Element 5 – Communications and Training was assessed at level 2, which was downgraded from the 2020 third-party assessment score of level 3. The drop in maturity level resulted from the absence of a process to validate that proper trainings are in place for compliance requirements. Table 30 below provides the maturity level score progress in Gas for each of the eight elements since the inception of the Compliance Maturity Model.

Table 30 – Gas Compliance Maturity Model – Assessment Scores by Element								
	2016	2017	2018	2019	2020	2021	2022	2023
Element	Baseline	3rd Party	3rd Party	3rd Party	3rd Party	PG&E	n/a	n/a
1. Risk Assessment	3	2	3	2	2	3	Assessment not performed	Assessment not performed
2. Program Governance	2	2	2	2	3	3		
3. Governance Documents	2	2	3	1	1	3		
4. Compliance Controls	1	1	1	1	1	1		
5. Communications & Training	2	3	Not Assessed	1	3	2		
6. Monitoring & Auditing	2	2	3	2	3	3		
7. Investigations & Response	2	3	3	1	2	3		
8. Enforcement & Incentives	1	1	3	1	2	3		

An Action Plan was executed in 2022 to address gaps identified in the 2021 self-assessment. A major effort was the pilot of a requirement owner certification survey in the company's enterprise compliance management tool MetricStream, which provides validation from requirement owners that they fully understand and embrace ownership of their compliance requirements.

In 2023, an Action Plan was executed for Gas to continue efforts to sustain or advance to a level 3 maturity level in seven of the eight elements. Gas fully implemented the requirement owner certification process in MetricStream and Certification was completed for all requirement owners of high and medium-risk compliance requirements. The certification also included a validation of compliance trainings by requirement owners, which addresses the training gap identified in the 2021 self-assessment. Follow-up items identified by requirement owners through the certification process included reassignment of requirement ownership and identification of trainings that were missing from the Learning Academy's training database. All identified follow-up items were resolved in 2023 and MetricStream was updated to reflect the correct information.

PG&E's 2024 Action Plan will continue to build on efforts in 2023 and includes preparation to implement the newly developed process to identify compliance controls associated with non-compliance issues and requirement owner certification. The 2024 Action Plan also includes implementation of a new Risk Prioritization effort that enables requirement owners to reassess risk rankings of their compliance requirements using the new Enterprise methodology. This effort will allow Gas to risk rank compliance requirements more effectively and to ensure work for the highest risk rank compliance requirements are properly prioritized. Additionally, Ethics and Compliance will perform an assessment in 2024 to determine the current maturity level scores for Elements 1, 2, and 5.

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

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

1. Building Expertise

PG&E employees require specialized skills 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. PG&E employees also receive a multitude of refresher trainings and recertification via in-person hands-on training and web-based trainings to ensure they stay current with new work methodologies, internal standards and procedures as described in the next section, and most but not least, current code and regulations to make our employees, assets, and the general public safe.

2. The Right Information to Do the Work

A highly-skilled workforce is most effective when provided with timely, accurate information. 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, PG&E uses written guidance documents, such as standards, procedures, and job aids. These documents are stored electronically in the Technical Information Library and are reviewed and updated routinely to reflect both regulatory requirements and best practices, as well as any lessons learned from Company or industry experiences. Additionally, these documents are available in real time to the field and contractors via a mobile application, making access easy while on site. Even so, it requires significant efforts to keep all personnel performing work in accordance with these documents and to ensure that personnel are made aware of any changes. Coworkers are provided with the requisite training and access to subject matter experts to maintain compliance.

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. E-mail communications are sent out that separate changes based on several categories, allowing employees to determine relevant changes more efficiently. Additionally, each document change is assessed for impact and, depending on the assessment, is rolled out in a layered approach using multiple communication channels as appropriate.

There are many channels utilized, such as simple emails or discussions from worker leadership, tailboards, direct group meetings with the people doing the work, or PG&E Academy training.

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 detailed information about asset history, materials, manufacturer, and location for the majority of assets. These systems help PG&E 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 promptly. 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 portfolio of work has been identified and approved, the PG&E Gas Resource Management team determines the number of internal and external resources that will be needed to complete the portfolio of work efficiently. PG&E maintains master agreements with multiple contractors and maintains a database of construction qualifications to effectively assign work to the appropriate and most effective resources. The allocation of work is proposed by the Gas Resource Management team and then reviewed and confirmed by a broader "Work Allocation Team" made up of members from our Gas Sourcing, Engineering, Project and Program Management, Contract and Construction Management teams who take into consideration workload, safety performance, and other factors when confirming resource assignments. PG&E uses workplans comparing the anticipated level of effort for planned work coupled with emergent work forecasts and compares that to internal resource capacity to signal the need for additional overtime, additional contractor resources, etc.

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 others are aimed externally to help PG&E identify opportunities for continuous improvement or pending regulatory changes. Figure 65 below details some of these processes and programs.

Figure 65 – Compliance Supportive Controls

Gas continues its focus on analyzing historical compliance data from SED inspections and self-reports to identify improvement opportunities. Leveraging the process management framework and data analytics, the Regulatory Compliance team was able to organize our top compliance challenges by seven non-conformance drivers and partner with our Process Owners (PO) and Process Managers (PM) in developing specific action items to address these top challenges. As a result of making data-driven decisions, Gas has made significant improvements in our compliance performance, with an overall downward trend of non-compliances since 2019. By 2023, Gas reduced non-compliances by over 36%

compared to 2019 levels and continues to find opportunities to achieve our internal goal of reducing non-compliances by 90% by 2025 compared to 2019 levels.

The Gas Regulatory Compliance team continued partnering with the QM and Internal Auditing teams to support a framework where Regulatory Compliance identifies compliance trends, Internal Auditing performs thorough investigations, and QM validates the effectiveness of the implemented preventative and corrective actions. As a result, Gas created quality assurance programs and is continuing to work with POs and PMs to implement additional controls in their processes to prevent non-conformances. This effort, in conjunction with the development of the Compliance Maturity Model mentioned in Section VI Compliance Framework, allows for continuous improvement to prevent non-compliance.

Gas placed additional focus on self-identifying non-conformances to build transparency with our regulators and compounded this effort by viewing these self-identified items as learning opportunities. Each self-identified item receives a work group evaluation to understand the apparent and contributing causes to the issue, leading to the development of preventative and corrective actions to drive improvements. These actions support the Plan, Do, Check, Act methodology integrated into our compliance and quality management frameworks.

VII. Continuous Improvement

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

1. Lean

In February 2021, PG&E began implementing our Enterprise Lean Operating System, with a focus on driving a culture of performance around the company's top-line metrics and key risk areas (e.g., Wildfire Management) and supporting our customers and employees closest to the work. The Enterprise Lean organization provides strategic direction for our Lean journey and empowers continuous improvement.

Lean Thinking refers to approaches that focus on elimination of waste in all forms and the smooth, efficient flow of materials and information throughout the value chain to obtain faster customer response, higher quality, and lower cost.

Lean leverages four plays (standards) to drive transparency, control, and predictability for every coworker across the system. The Enterprise Lean Organization has focused much of 2022 and 2023 on strategy deployment building Lean capabilities, and standard tools. Many teams within Electric and Gas were trained to use Lean Visual Management boards, implement the Lean Operating Reviews, and leverage Lean Problem-Solving methods for faster results.

a. Electric & Gas Performance and Process Improvement Team (E&G PPI)

E&G PPI (formerly the Lean Capability Center) partners closely with the Enterprise Lean organization and supports our functional area partners in Gas and Electric, along with Operations Support. E&G PPI helps these functional areas move their businesses forward through Lean maturity and waste elimination projects, allowing us to improve our processes continuously and tenaciously. Major sub-teams within the E&G PPI functional team include:

- Electric and Gas Lean Implementation Sub-Team: Implements the five basic plays of Lean: Visual Management, Operating Reviews, Problem Solving, Standard Work, and Waste Elimination within Gas and Electric.
- Electric and Gas Process Architecture Strategy and Implementation Sub-Team: Develops the standards and governance structures to implement and sustain a Process Architecture encompassing core operational, functional, and enabling processes for both Gas and Electric.
- Electric and Gas Performance Improvement Sub-Team: Provides problem solving and waste elimination support and coaching to the Electric, Gas, and Operations Support functional area teams.

E&G PPI team accomplishments in 2023 include:

- Established 15 Lean Model Standard Yards across the five regions and launched Model Standard Yard "Go and See" program;
- Trained 120 frontline leaders and over 1,100 coworkers on the five Lean Basic Plays in the Model Standard Yards;
- Partnered with Gas leaders and teams to deliver savings across all cost categories;
- Conducted waste elimination events; and
- Matured Process Architecture governance processes for Gas and Electric

E&G PPI team plans for 2024 include:

- Establishing Lean Standard Yards in both Electric and Gas across the remaining service yards, supporting the implementation of more cross-functional problem-solving sessions;
- Promoting more standards and structure applying Lean principles; and
- Promote and mature Lean process architecture to provide a framework for driving cross-functional collaboration and accountability for operational performance.

Continuing efforts in direct coaching and support to help the Gas Operations & Engineering functional area teams deliver on waste elimination objectives of improving safety, quality, cost, delivery, and morale.

As we become more adept at the Lean way of working, the result will be a more empowered workforce, improved problem solving, better transparency of work, performance, and drivers of work across disciplines, a more organized and efficient cadence of meetings to support coworkers, and improved service for our customers and communities.

2. Quality Management

Gas Quality Management (QM) is comprised of Quality Assurance (QA) at the Gas level and Quality Control (QC) situated either at the Gas level or within the functional work groups. QC looks for defects in the work being performed and in the corresponding records. QA is a combination of Quality Verification assessments that validate the effectiveness of QC looking for nonconformances to procedures and QA audits that look to prevent defects by identifying process gaps and recommending corrective actions. Together, QA and QC under the Quality Management System (QMS) umbrella are working together to drive down non-compliance risk. The following illustration depicts the layers of defense working to mitigate non-compliance risk.

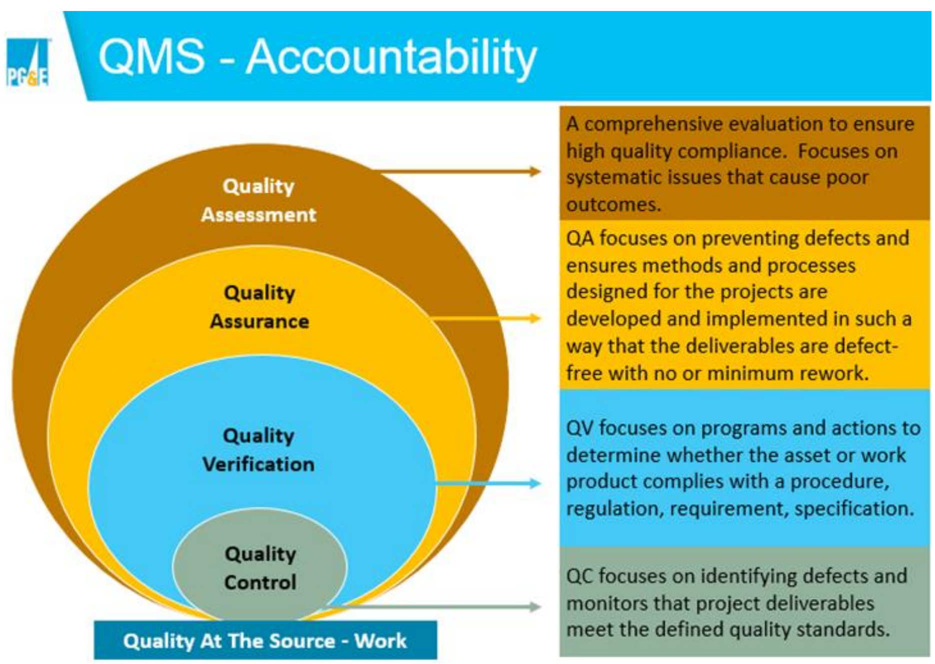

Figure 66 – Layers of Defense Against Non-compliance Risk

The QMS framework and collaborative approach to quality allows for continuous improvement and drives consistency by identifying nonconformances, recommending corrective actions, and following up with mentoring and coaching for people doing the work. It also continues to align with the fundamental principles of the QMS which leverages the "PDCA" framework (Figure 67 below). PDCA is the 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.

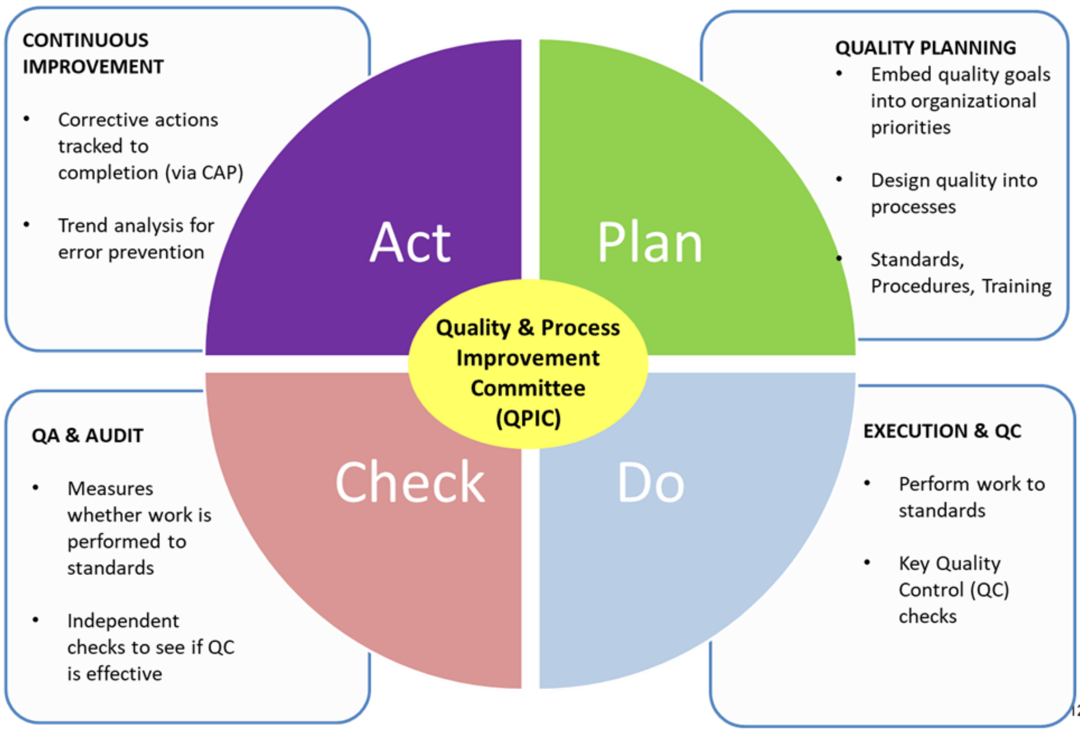

Figure 67 – QMS Fundamental Principles

In 2023, T&D construction As-Built job packages, Regulator Stations and Valves, USA Tickets, Leak Survey (LS) records and rectifiers continued to be reviewed by QC and QA. Field Quality control for construction was merged with Field QA to form Quality Verification (QV) in order to expand the assessment capabilities of the team and assess more of the work performed by General Construction and Maintenance and Construction. There were 17 active QC/QV programs as of December 2023, shown in Table 31 below.

Table 31 – List of Quality Management Programs as of 2023	
Leak Survey T&D Post Assessment	GPOM Odorization
Leak Survey Distribution Records	Distribution Construction
Field Services	Transmission Construction
Instrument Calibration	Regulator Station Maintenance
Corrosion – Exposed Pipe/Spans	Damage Prevention – Locate and Mark
Damage Prevention – USA Tickets	Gas T&D As-Builts
Distribution Maintenance	Corrosion – Rectifiers
Post Construction Asset Validation	Damage Prevention - Instrument Calibration
Valve Maintenance	

In keeping with our QMS maturity journey and expansion of our quality oversight, we also accomplished the following in 2023:

- Performed over 103,000 QC records/as built job package assessments;
- Performed over 7,500 QA assessments (field and records combined);
- Launched new LS distribution records assessments program;
- Created weekly and monthly dashboards for each functional area to share quality performance and trends related to quality assessments;
- Successfully made the No Conflict/No Conflict Screened USA Ticket program a regular program; and,
- Supported the initiative of moving scanning earlier in the as-built process, to follow construction complete in order to ensure documentation integrity (as-built document scanning after QC).

In 2023, quality performance across Gas continued to be measured in terms of a natural error rate where all nonconformances (regardless of high, medium, or low risk ranking) were equal and the rate was calculated by dividing the number of nonconformances found by the number of items assessed. This approach continues to drive corrective actions for all nonconformances versus only those considered high risk. Over the past few years, high risk nonconformances have been vastly reduced, allowing us to expand our focus. PG&E continues to track high risk findings and track the corrective actions required to remedy a non-conformance.

3. 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 enforce rigorous standards for incoming material and assures that qualified suppliers provide material that meets PG&E's product qualification requirements. SQA has significantly reduced Defective Parts Per

Million (DPPM) since 2014. The 2023 DPPM performance was 202 against the target of 260. In 2021, SQA introduced a new metric (QPR = Quality Performance Rating), a proactive monitoring of suppliers' improvement of overall performance including, DPPM, responsiveness of suppliers' corrective actions, Quality Management System, and other technical quality parameters that will aid PG&E in reducing risk with more targeted quality efforts. For 2024, SQA will use QPR as our main quality metric, and QPR has been added to our Executive dashboard.

In 2023, we identified seven suppliers that needed improvement by using the QPR assessment. With our support, six of the seven suppliers reached PG&E's acceptable quality level.

SQA has achieved significant performance since 2013 for quality programs and is driving towards the ultimate goal of having supplied material be defect free. Eighty-six percent of gas high risk suppliers are ISO certified, and SQA was re-certified to ISO 9001:2015 QMS in 2023 and had zero non-conformities for all audits. Through PG&E's cross functional teams and supplier partners, SQA processed 78 supplier change requests in 2023 and two supplier material recalls. In addition, SQA conducts an annual supplier survey to identify improvement opportunities.

4. Research and Development and Innovation

The Research and Development (R&D) Group brings innovative technologies and solutions from industry, government, and academia to PG&E's Gas Operations.

The R&D team joined the Utility Partnerships and Innovation Organization, as part of the Grid Research, Innovation and Development (GRiD) team in 2022. R&D and Innovation's work is prioritized in alignment with PG&E's R&D Strategy Report, with three main areas of focus: (1) maintain and increase the safety and reliability of the system while reducing Operations and Maintenance (O&M) costs, (2) Reduce methane emission from the gas system, and (3) Decarbonize the gas system. Each area of focus identified the highest priority problem statements to assure that new technologies and methods are effectively leveraged to improve the safety, reliability, and cost effectiveness of PG&E's assets. The scope includes Natural Gas and cleaner fuels such as biomethane and hydrogen to support the decarbonization of the gas system towards carbon neutral energy delivery by 2040 conforming with PG&E's Climate Strategy Report .

PG&E also uses the Center for Gas Safety and Innovation in Dublin, California. This facility consists of work and lab space with advanced tools, testing capabilities, and lab resources, with the goal of continuing to lead in the development 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 M&C 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.

PG&E collaborates with national and international R&D organizations such as the Pipeline Research Council International (PRCI), the Northeast Gas Association's research group (NYSEARCH), Operations Technology Development and Utilization Technology Development. PG&E also works closely with R&D programs at the California Energy Commission (CEC), Pipeline and Hazardous Materials Safety Administration (PHMSA), the California Air Resources Board (CARB), the federal Department of Energy and multiple universities including Stanford (through the Natural Gas Initiative), University of California, Berkeley, University of California, Davis, University of California, Irvine, etc. mobilizing and leveraging a broad spectrum of expertise to bring innovative solutions to Gas in the most effective way.

In 2023, the R&D and Innovation team managed and implemented a broad portfolio of nearly 150 active projects in collaboration with leading U.S. and overseas utilities, pipeline operators, and R&D organizations. Examples of 2023 achievements include:

- Fiber Optic Monitoring of Pipelines at Geohazards Project successfully installed next-generation technology on a gas transmission line to determine the full-length strain profile more accurately on the affected pipelines from seismic activities, without excavating the line and in a manner more cost efficient than traditional in-line inspections. This work fits PG&E's overall strategy of improving safety at reduced cost and ranks as one of the high priorities in the company's TIMP Fault Crossing Program. Partnering with Paulsson Incorporation, UC Berkeley, and field construction vendor Snelson, PG&E worked on this installation starting in May 2023. Installation took approximately one week and was coordinated to occur within a 1,200-ft pipeline re-routing construction schedule. The project is the first direct pipeline full-length strain profile monitoring in the North American oil and gas industry and is expected to provide on-demand monitoring data for years to come. This project was highlighted in PG&E Currents on August 29, 2023 PG&E Installing New Technology to Enhance Pipeline Safety During Seismic Activity. (Figures 68 and 69).
- Real-time Detection of Mechanical Impacts through monitoring CP current variation at rectifiers is a cost-effective solution that can be easily integrated into existing CP systems without requiring modification. This technology increases risk awareness by providing real-time detection of the mechanical threats to steel pipelines, allowing operators to respond sooner, thereby reducing risks. Feasibility project PRCI ROW-1-01 was successfully completed in November 2023 with participation of 11 operators, and a 12-month pilot run at 3 field sites (high risk of third-party damages) in PG&E service territory is expected to start early 2024 as a Gas Technology Institute (GTI)/Operations Technology Development consortium project. The technology will be included in

the “Oil and Gas Pipelines: Integrity and Safety Handbook” 2nd Edition, edited by R. Winston Revie. (Figures 70 and 71)

- Completion of an internal pilot with a US-based gas mapping LiDAR technology for methane detection and quantification using a helicopter. A 12-square mile area of our gas distribution/transmission pipeline was surveyed in the Fresno area in Q2 of 2023 with promising results. The sensor was able to detect, locate, and quantify methane emissions from the air, it identified several new and existing open leaks, and identified a customer leak (post meter) within the delineated project area. Next steps include evaluation of its probability of detection performance through NYSEARCH expected to start in 2024. (Figure 72)
- In June 2023, PG&E submitted an application for its selected pilot project from West Biofuels, LLC located in Woodland, California. This project will test new technology that converts wood and forest waste into a clean source of pipeline-ready natural gas. The facility uses advanced technology to convert most of the renewable carbon in the biomass into natural gas, maximizing output and eliminating emissions during production.
- Completion of NYSEARCH Project M2020-002 “Impact of Hydrogen/Natural Gas Blends on Local Distribution Company Infrastructure Integrity.” The purpose of this study with GTI Energy is to determine if blending hydrogen into fuel gas will change the physical properties of elastomers used as materials of construction in a natural gas delivery system. Figure 73 shows the elastomers within coupon test vessels that underwent several tests, including shrinking, swelling, creep, and stress relaxation. More information can be found on the NYSEARCH Page.

Figure 68 – Field installation of the advanced distributed fiber optic sensor monitoring systems on L-300B at a Calaveras Fault-crossing site in Gilroy.

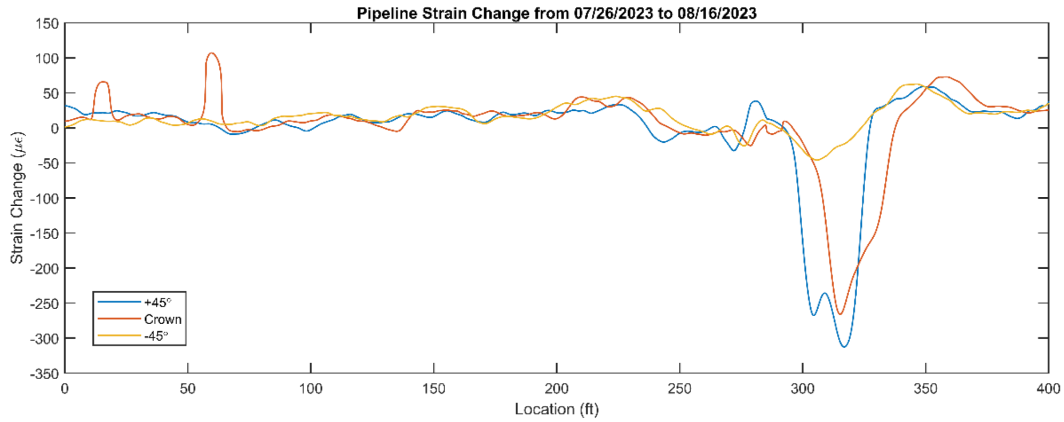

Figure 69 – Pipeline Strain Change due to some field construction operation on the site

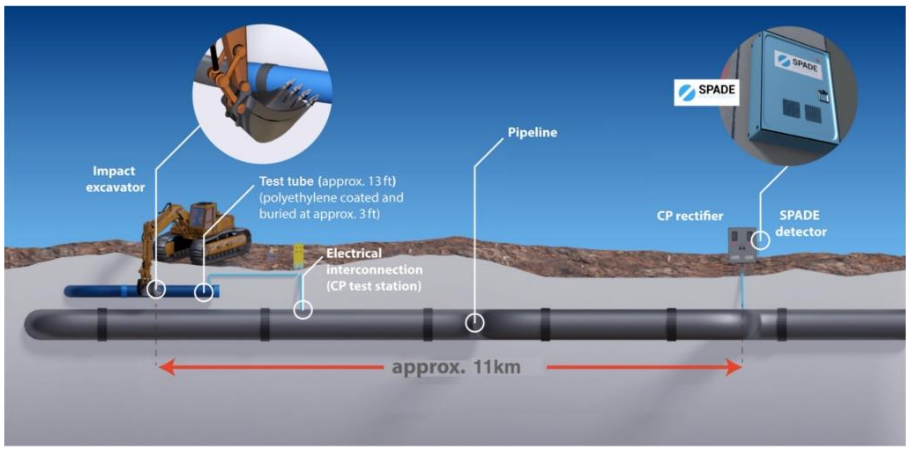

Figure 70 – Schematic of the SPADE Technology in pilot - Real-time detection of excavator impact

Figure 71 –SPADE demonstrating unit installed on PG&E Transmission Pipeline's Cathodic Protection System network at Hollister in June 2023

Figure 72 – (L-R) Shows a leak indication from the aerial photography report – Aligns with the actual leak location

Figure 73 – Elastomer Coupon Test Vessel

5. 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.

a) INDUSTRY STANDARDS WRITTEN BY SUBJECT MATTER EXPERTS

One informal benchmarking practice that PG&E uses 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 United States, 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 international asset management standard, and has both achieved and sustained certification.

PG&E relies on associations such as the AGA, ASME, INGAA, PSE&G, and the API to facilitate the development of best practices, to 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, to 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.

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, 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 Best Practices Program, AGA SOS Survey Program, AGA Leading Indicator Survey, and other safety and occupational hazard survey programs by both distributing and responding to surveys with topic-specific information requests and uses the data provided by other U.S. utility gas companies.

PG&E volunteered to participate in AGA'S Enhanced Peer Review Program in 2023. The AGA review team examined our safety culture and pipeline safety risk management as follows:

- Safety Culture: The AGA Review Team endeavored to identify how safety is perceived by different levels in the organization. The team reviewed strengths and weaknesses in the company's overall safety program relative to known industry practices and programs.
- Pipeline Safety Risk Management: The team reviewed procedures, programs, and initiatives that PG&E uses to manage risk on transmission and distribution pipeline assets.

In 2023 PG&E also hosted an AGA Best Practices roundtable for a Public Awareness special topic that was surveyed in 2023. This provided an in-depth discussion for participants from a number of Gas utilities in the nation and provided PG&E with a good opportunity for employees to participate in discussions surrounding Public Awareness.

e) Interstate Natural Gas Association of America (INGAA)

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 they are widely recognized in the industry as such. INGAA has a membership base that owns approximately 200,000 miles of natural gas pipeline in North America. PG&E relies on INGAA to facilitate the identification, development and sharing of best practice materials.

f) The Association for Materials Protection and Performance (AMPP)

PG&E relies on AMPP, formerly known as National Association of Corrosion Engineers (NACE), to identify and develop standards, test methods, and material recommendations that are widely regarded as the best in the field for corrosion—specifically for CP and coatings. AMPP creates these materials through the subject matter expertise of its members. AMPP 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 and 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 among member utility companies that focus on sharing benchmark data on an annual basis. PG&E participates in the annual benchmarking study run by PSE&G and gathers valuable cost data. This data is then used in target setting for corresponding performance measures at PG&E.

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

i) Additional Benchmarking Efforts

In addition to participating in numerous associations, PG&E also develops benchmarking, by 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 32 – 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 Workday Case Rate [(a)]	LWD per 200,00 hours worked
Total Dig-in Reduction	Total Number of dig-in incidents per 1,000 tickets
Third Party Dig-In Reduction	Number of third-party dig-in incidents per 1,000 tickets
Cross-bore intrusions found	Number of cross-bore intrusions found in a year

(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 2024 Plan update demonstrates PG&E's commitment and progress in implementing processes, programs, and procedures to achieve the stand of keeping everything and everyone safe. PG&E's True North Strategy sets the tone for the Company to focus on people, the planet, and prosperity. The PSEMS 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. PG&E maintains an asset management system to help address risks by knowing the assets and their condition, understanding the risks involving those assets, and developing and implementing risk reduction strategies with the intent to achieve risk reduction in balance with operational performance and cost. PG&E has made continued progress but recognizes that there is always more to be done in its journey to Gas Safety Excellence.

IX. Endnotes

1 See Attachment 01 for a Table of Concordance that provides a mapping between the Public Utilities Code Sections 961 and 963 and the Gas Safety Plan sections.

2 In October 2011, the California legislature signed into law 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).

3 In 2024, the Coworker Town Hall meetings have been renamed LTH as they focus on developing leaders to better support the frontline coworkers.

4 Degree considerations can include: physical harm vs. immediate life threatening; redundancy vs. single point failure; recovery vs. point of no return; local vs. widespread, monetary impact.

5 An employee-led team that promotes safe work habits, shares information and best practices, promotes open and honest communications, and finds innovative methods to perform work safely.

6 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.

7 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.

8 See Risk Management Process section for definitions of top risks.

9 PG&E submits the Risk Spend Accountability Report annually every April in accordance with D.19-04-020.

10 API 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.

11 API 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.

12 After several iterations, the most recent proposal was submitted for CalGEM review and approval on January 19, 2024.

13 The compressor at the Pleasant Creek storage facility has been isolated from the storage field. A Commission decision is pending on the sale of the facility.

14 The Transmission Pipe asset family includes valves and fittings outside of station boundaries and not otherwise included in the M&C 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.

15 As set forth in 49 CFR Part 192, Subpart O.

16 Executive forums include the Executive Leadership Team meeting (the Chief Executive Officer (CEO) and her direct reports), the Senior Leadership Team meeting (the CEO, her direct reports, and their direct reports) and the Run the Business meeting (all PG&E officers).

17 49 CFR §192.614.

18 California Government Code §4216.

19 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.

20 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.

21 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.

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

23 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.

24 215 deaths related to the February 2021 winter storm in Texas were caused by extreme cold exposure, exacerbation of pre-existing illness, carbon monoxide exposure, or fire.

25 PG&E's California Gas Transmission Pipe Ranger website Supply and Demand Archives, https://www.pge.com/pipeline/en/operating-data/historical-archives/cgt-supplydemand-search.html. Enter a start date of "12/31/2023" and end date of "01/01/2023," download Excel file, and add values listed in "Total System Supply" row.

26 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, "Emergency plans." and (§)192.605 "Procedural manual for operations, maintenance, and emergencies."

X. APPENDIX A – LIST OF FIGURES

XI. Appendix B – List of Tables

XII. APPENDIX C – LIST OF ATTACHMENTS

Attachment 1 – Table of Concordance

Attachment 2 – 2024 - 2025 Natural Gas Leak Abatement Compliance Plan

Attachment 3 – Change Logs for PG&E's Asset Management Plans, Company Emergency Response Plan, and Gas Emergency Response Plan

Attachment 4 – Change Log for 2024 Gas Safety Plan

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 1

TABLE OF CONCORDANCE

2024 Gas Safety Plan Table of Concordance

PG&E provides this Table of Concordance to demonstrate the Gas Safety Plan compliance with the Public Utility Code (PUC) Sections 961 and 963 (b)(3):

PUC Section	Section Location(s) in Gas Safety Plan
961 (a): For purposes of this section, "gas corporation workforce" means the employees of a gas corporation and employees of an independent contractor of the gas corporation while working under contract with the gas corporation.	V. Workforce
961 (b) (1): Each gas corporation shall develop a plan for the safe and reliable operation of its commission-regulated gas pipeline facility that implements the policy of paragraph (3) of subdivision (b) of Section 963, subject to approval, modification, and adequate funding by the commission.	The 2024 Gas Safety Plan is submitted as required by this section.
961 (b) (2): By December 31, 2012, the commission shall review and accept, modify, or reject the plan for each gas corporation as part of a proceeding that includes a hearing. The commission shall build into any approved plan sufficient flexibility to redirect activities to respond to safety requirements.	Not applicable to PG&E.
961 (b) (3): Each gas corporation shall implement its approved plan.	The 2024 Gas Safety Plan provides a view into the safety activities PG&E pursues every day and highlights the specific safety work performed in 2023.
961 (b) (4): The commission shall require each gas corporation to periodically review and update the plan, and the commission shall review and accept, modify, or reject an updated plan at regular intervals thereafter. The commission, pursuant to Section 1701.1, shall determine whether a proceeding on a proposed update to a plan requires a hearing, consistent with subdivision (e).	PG&E reviews and updates its Gas Safety Plan on an annual basis. See I. Introduction.

PUC Section	**Section Location(s) in Gas Safety Plan**
961 (c): The plan developed, approved, and implemented pursuant to subdivision (b) shall be consistent with best practices in the gas industry and with federal pipeline safety statutes as set forth in Chapter 601 (commencing with Section 60101) of Subtitle VIII of Title 49 of the United States Code and the regulations adopted by the United States Department of Transportation pursuant to those statutes.	References to programs that comply with federal pipeline safety statutes and/or conform to industry best practices are referenced throughout the document as applicable.
961 (d): The plan developed, approved, and implemented pursuant to subdivision (b) shall set forth how the gas corporation will implement the policy established in paragraph (3) of subdivision (b) of Section 963 and achieve each of the following:	
961 (d) (1): Identify and minimize hazards and systemic risks in order to minimize accidents, explosions, fires, and dangerous conditions, and protect the public and the gas corporation workforce.	I. 5 Workforce Safety I. 6. Rewarding Safety Excellence II. Safety Culture III. Process Safety IV. 2. d. Measurement and Control (M&C) IV. 3. Risk Management Process IV. 5. a. v. Pipeline Patrol IV. 5. b. Pipeline Markers IV. 5. f. Vintage Pipe Replacement IV. 5. h. Corrosion Control IV. 5. j. Leak Survey IV. 5. l. Overpressure Elimination Initiative IV. 7. b. Operations Clearance Procedure

PUC Section	Section Location(s) in Gas Safety Plan
	IV. 7. Mitigating the Risk of Inadequate Response and Recovery IV. 7. c. Security IV. 7. d. Valve Automation V. Workforce
961 (d) (2): Identify the safety-related systems that will be deployed to minimize hazards, including adequate documentation of the commission-regulated gas pipeline facility history and capability.	IV. 4. Records and Information Management IV. 5. e. Strength Testing VI. Compliance Framework VII. 2. Quality Management
961 (d) (3): Provide adequate storage and transportation capacity to reliably and safely deliver gas to all customers consistent with rules authorized by the commission governing core and noncore reliability and curtailment, including provisions for expansion, replacement, preventive maintenance, and reactive maintenance and repair of its commission-regulated gas pipeline facility.	IV. 2. a. Gas Storage IV. 2. c. Transmission Pipe IV. 2. d. Measurement and Control (M&C) IV. 2. e. Distribution Mains and Services IV. 2. f. Customer Connected Equipment IV. 2. g. Liquefied Natural Gas and Compressed Natural Gas IV. 5. c. Distribution Pipeline Replacement IV. 5. f. Vintage Pipe Replacement IV. 5. h. Corrosion Control IV. 5. m. Community Pipeline Safety Initiative IV. 6. a. System Capacity Design Criteria IV. 6. b. Inventory Management IV. 7. a. Gas Systems Operations and Control

PUC Section	Section Location(s) in Gas Safety Plan
	VII. 2. Quality Management
961 (d) (4): Provide for effective patrol and inspection of the commission-regulated gas pipeline facility to detect leaks and other compromised facility conditions and to effect timely repairs.	IV. 5. a. Damage Prevention IV. 5. a. i. Public Awareness IV. 5. a. ii. Dig-in Reduction Team IV. 5. a. iii. Locate and Mark Program IV. 5. a. iv. Standby Governance IV. 5. a. v. Pipeline Patrol IV. 5. d. Cross-Bore Mitigation IV. 5. g. In-Line Inspection IV. 5. j. Leak Survey IV. 5. k. Leak Repair VI. 4. Supportive Controls
961 (d) (5): Provide for appropriate and effective system controls, with respect to both equipment and personnel procedures, to limit the damage from accidents, explosions, fires, and dangerous conditions.	II. 1. c. Material Problem Reporting III. Process Safety IV. 2. f. Customer Connected Equipment IV. 2. g. Liquefied Natural Gas and Compressed Natural Gas IV. 5. l. Overpressure Elimination Initiative IV. 7. Mitigating the Risk of Inadequate Response and Recovery IV. 7. a. Gas System Operations and Control IV. 7. c. Security IV. 7. d. Valve Automation

PUC Section	Section Location(s) in Gas Safety Plan
	V. 3. Workforce Training V. 4. Gas Operator Qualifications V. 5. Contractor Safety and Oversight VII. 5. Benchmarking and Best Practices
961 (d) (6): Provide timely response to customer and employee reports of leaks and other hazardous conditions and emergency events, including disconnection, reconnection, and pilot-lighting procedures.	I. 4. Public Safety IV. 5. k. Leak Repair IV. 7. a. Gas Systems Operations and Control IV. 7. d. Valve Automation IV. 7. e. Emergency Preparedness and Response
961 (d) (7): Include appropriate protocols for determining maximum allowable operating pressures on relevant pipeline segments, including all necessary documentation affecting the calculation of maximum allowable operating pressures.	IV. 5. e. Strength Testing IV. 5. l. Overpressure Elimination Initiative
961 (d) (8): Prepare for, or minimize damage from, and respond to, earthquakes and other major events.	IV. 5. i. Earthquake Fault Crossings IV. 7. e. Emergency Preparedness and Response
961 (d) (9): Meet or exceed the minimum standards for safe design, construction, installation, operation, and maintenance of gas transmission and distribution facilities prescribed by regulations issued by the United States Department of Transportation in Part 192 (commencing with Section 192.1) of Title 49 of the Code of Federal Regulations.	IV. 1. Asset Management System
961 (d) (10): Ensure an adequately sized, qualified, and properly trained gas	V. Workforce

PUC Section	Section Location(s) in Gas Safety Plan
corporation workforce to carry out the plan.	
961 (d) (11): Any additional matter that the commission determines should be included in the plan.	PG&E is not aware of any additional matters the commission has requested be included.
961 (e): The commission and gas corporation shall provide opportunities for meaningful, substantial, and ongoing participation by the gas corporation workforce in the development and implementation of the plan, with the objective of developing an industrywide culture of safety that will minimize accidents, explosions, fires, and dangerous conditions for the protection of the public and the gas corporation workforce.	II. Safety Culture V. 6. Partnership with Labor Unions
961 (f): Nothing in this section limits the obligation of a gas corporation to provide adequate service and facilities for the convenience of the public and its employees pursuant to Section 451 or the authority of the commission to enforce that obligation under state law.	Not applicable.
963 (b) (3): It 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. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates.	The contents of PG&E's Gas Safety Plan provide a view into the safety activities PG&E pursues every day and highlights the specific safety work performed in 2023. 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.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 2

NATURAL GAS LEAK ABATEMENT COMPLIANCE PLAN

PACIFIC GAS AND ELECTRIC COMPANY'S 2024 LEAK ABATEMENT COMPLIANCE PLAN MARCH 15, 2024

Rev. [November 6, 2024][1]

SECTION A: PLAN INTRODUCTION AND SUMMARY

Meeting the challenge of climate change is central to Pacific Gas and Electric Company's (PG&E) vision of clean and resilient energy for all. Consistent with our True North Strategy, PG&E works to reduce greenhouse gas (GHG) emissions and environmental impacts from our operations and acts as a valuable partner in California and beyond.

On January 22, 2015, the California Public Utilities Commission (CPUC or Commission) issued the Order Instituting Rulemaking (OIR) (R.) 15-01-008 to implement the provisions of Senate Bill (SB) 1371 (Statutes 2014, Chapter 525). SB 1371 requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities consistent with Public Utilities Code § 961(d), § 192.703(c) of Subpart M of Title 49 of the Code of Federal Regulations (CFR), the Commission's General Order (GO) 112-F, and the state's goal of reducing GHG emissions. In the June 15, 2017, Decision (D.) 17-06-015, the Commission adopted 26 Best Practices (BP) related to natural gas leak abatement (phase one). PG&E's Natural Gas Leak Abatement Program includes annual methane emission tracking and reporting as well as the submission of a biennial best practice compliance plan. This 2024 Leak Abatement Compliance Plan (2024 Compliance Plan) is the fourth biennial Leak Abatement Compliance Plan prepared in accordance with the Commission's decision and covers the years 2024-2025.

PG&E has made strides in reducing the methane emissions on its systems through the execution of its first three Compliance Plans. The main measures that have been implemented are:

- Under the 2018-2019 Compliance Plan:
    - Acceleration of detection and repair of larger leaks of its distribution system (Super Emitter Program)
    - Acceleration of distribution leak survey from 5 to 3 years
    - Application of cross compression and drafting practices on scheduled backbone transmission pipeline projects
    - Replacement of more than 100 high bleed controllers at Compressor Stations and Storage Facilities
    - Introduction of quarterly leak surveys at Compressor Stations and Storage Facilities
- Under the 2020-2021 Compliance Plan:
    - Implementation of meter set leak bubble classification framework and repair prioritization
    - Addition of project bundling as an abatement technique to reduce emissions

[1] Limited revisions have been made to the original 2024 Compliance Plan to address errors in the submission.

associated with project blowdowns
    - Extension of cross compression activities to local transmission projects
    - Further reduction of the pipeline pressure during cross-compression on scheduled backbone transmission pipeline projects
- Under the 2022-2023 Compliance Plan
    - Decreased the Super Emitter threshold from 10 to 7 standard cubic feet per hour (scfh)
    - Completed Super Emitter surveys earlier in the year
    - Leveraged Super Emitter drives for Distribution Integrity Management Program (DIMP) Vintage pipeline surveys, which improved cost-effectiveness of this annual survey
    - Replaced 10 high bleed pneumatic devices at Transmission Metering & Regulating (M&R) Stations
    - Extended blowdown reduction strategies to compressor station and storage facilities

CPUC, CARB and PG&E collaborated to adjust the 2015 baseline emissions to incorporate improved measurement and estimation methods, helping the CPUC and PG&E to more accurately estimate forecasted emission reductions of proposed measures and effectively evaluate the absolute and relative cost-effectiveness of proposed measures. Baseline adjustments and improved emissions estimates also better align with the Annual CPUC Joint Reports, resulting in more cohesive public reporting data.

In October 2022, CPUC Safety Policy Division (SPD) approved the following adjusted 2015 baseline emissions for PG&E:

Table 1 – 2015 Baseline Emissions Changes as of 2022

Appendix #	System Category	Emission Source Category	Original 2015 Baseline Emissions (Mscf)	Adjusted 2015 Baseline Emissions (Mscf)
3	Transmission Compressor Stations	Component Vented Emissions	N/A	10,172
		Component Fugitive Leaks	15,823	16,928
4	Distribution Mains and Services Pipelines	All Damages (Fugitives)	146,335	141,102
5	Distribution Metering and Regulating Stations	Station Leaks & Emissions (Fugitives)	741,986	9,440
		Meter Leaks (Fugitives)	636,034	245,907

6	Meter Set Assemblies	All Damages (Fugitives)	N/A	5,233
7	Underground Storage	Storage Leaks & Emissions (Fugitives)	11,870	2,036
		Component Vented Emissions	N/A	86,681
		Component Fugitive Leaks	10,574	75,957
		Dehydrator Vent Emissions (Fugitives)	6,761	13

In 2023, CPUC Safety Policy Division (SPD) approved the following adjusted 2015 baseline emissions for PG&E:

Table 2 – 2015 Baseline Emissions Changes as of 2023

Appendix #	System Category	Emission Source Category	Original 2015 Baseline Emissions (Mscf)	Adjusted 2015 Baseline Emissions (Mscf)
1	Transmission Pipelines	Component Vented Emissions	4,591	35,912
4	Distribution Mains & Services	Pipeline Leaks (Fugitives)	626,590	481,638

With these baseline adjustments and current programs/measures in place (i.e., Transmission Blowdown Abatement Strategies, Super Emitter Program, Damage Prevention Program, and implementation of the CARB Oil & Gas Rule), PG&E has achieved the 20 percent reduction compared to the 2015 baseline by 2025 compliance goal.

PG&E will explore the following measures to reach the 40 percent reduction target by 2030:

- Continue to decrease the SE threshold and increase SE survey frequency
- Measurement and Control (or Regulator) station leak and emission management
- Continuous prioritization of the Distribution Main & Service leaks based on size estimated from vehicle-based measurements
- Meter set leak repair prioritization (Class C, D)
- Extending blowdown reduction strategies to more system categories

Table 3 compares the 2015 baseline emissions with the 2022 reported emissions, as reported in PG&E's 2022 Natural Gas Leak Abatement Annual Report, for each system category and the Best Practices that support emissions reduction for that system category. At this time, projections for 2023 emissions are unavailable and will be submitted on June 15, 2024 in PG&E's Natural Gas Leak Abatement Annual Report.

Table 3 - 2015 Baseline vs. Reporting Year (RY) 2022 Emissions, including Supporting Best Practices							
System Categories	**Emission Source Categories**	**Fugitive or Vented**	**For Informational and Reference Purposes Only: Original 2015 Baseline Emissions (Mscf)**	**Approved Adjusted 2015 Baseline Emissions (Mscf)**	**2022 Total Annual Volume of Leaks & Emissions (Mscf)**	**Percentage Change for Year Over Year Comparison from Approved Adjusted 2015 Baseline to 2022**	**Best Practice Support Emissions Reduction**
Transmission Pipelines	Pipeline Leaks	Fugitive	3,701	3,701	3,636	**(1.8%)**	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It
	All Damages	Fugitive	81,793	81,793	2,134	**(97.4%)**	BP 24 - Dig-Ins / Public Education Program BP 25 - Dig-Ins / Company Standby Monitors BP 26 - Dig-Ins / Repeat Offenders
	Blowdowns	Vented	251,227	251,227	122,745	**(51.1%)**	BP 3 - Pressure Reduction Policy BP 4 - Project Scheduling Policy BP 5 - Methane Evacuation Procedure BP 6 - Methane Evacuation Work Order Policy BP 7 - Bundling Work Policy BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Emissions	Vented	4,591	35,912	28,742	**(20.0%)**	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Leaks	Fugitive	--	--	N/A	**–**	n/a
	Odorizers	Vented	135	135	156	**16.1%**	n/a
Transmission M&R Stations	Station Leaks & Emissions	Fugitive	579,240	579,240	554,619	**(4.3%)**	n/a
	Blowdowns	Vented	65,456	65,456	680	**(99.0%)**	n/a
Transmission Compressor Stations	Compressor Emissions	Vented	70,186	70,186	9,964	**(85.8%)**	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities

	Compressor Leaks	Fugitive	--	0	0	–	n/a
	Blowdowns	Vented	19,864	19,864	26,253	**32.2%**	BP 3 - Pressure Reduction Policy BP 4 - Project Scheduling Policy BP 5 - Methane Evacuation Procedure BP 6 - Methane Evacuation Work Order Policy BP 7 - Bundling Work Policy BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Emissions	Vented	--	10,172	19,748	**94.1%**	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Leaks	Fugitive	15,823	16,928	5,571	**(67.1%)**	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It BP 22 - Pipe Fitting Specifications
	Storage Tank Leaks & Emissions	Vented	N/A	0	0	**0.0%**	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It
Distribution Main & Service Pipelines	Pipeline Leaks	Fugitive	626,590	481,638	302,684	–	BP 15 - Gas Distribution Leak Surveys BP 16 - Special Leak Surveys BP 21 - Find It/Fix It BP 22 - Pipe Fitting Specifications
	All Damages	Fugitive	146,335	141,102	53,596	**(62.0%)**	BP 24 - Dig-Ins / Public Education Program BP 25 - Dig-Ins / Company Standby Monitors BP 26 - Dig-Ins / Repeat Offenders
	Blowdowns	Vented	141	141	100	**(29.4%)**	n/a
	Component Emissions	Vented	N/A	0	0	–	n/a
	Component Leaks	Fugitive	N/A	0	0	–	n/a

Distribution M&R Stations	Station Leaks & Emissions - Leak-Based	Fugitive	741,986	9,440	3,534	**(62.6%)**	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It BP 22 - Pipe Fitting Specifications
	All Damages	Fugitive	--	0	51	**–**	n/a
	Blowdowns	Vented	147	147	197	**34.0%**	n/a
Customer Meters	Meter Leaks - Leak-Based	Fugitive	636,034	245,907	250,445	**1.8%**	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It BP 22 - Pipe Fitting Specifications
	All Damages	Fugitive	--	5,233	5,592	**6.9%**	BP 24 - Dig-Ins / Public Education Program BP 25 - Dig- Ins / Company Standby Monitors BP 26 - Dig-Ins / Repeat Offenders
	Vented Emissions	Vented	231	231	197	**(14.7%)**	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
Underground Storage	Storage Leaks & Emissions	Fugitive	11,870	2,036	2,064	**1.4%**	BP 17 - Enhanced Methane Detection BP 19 - Above Ground Leak Surveys BP 21 - Find It/Fix It BP 22 - Pipe Fitting Specifications
	Compressor Emissions	Vented	5,360	5,360	885	**(83.5%)**	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Compressor Leaks	Fugitive	--	0	–	**–**	n/a

	Blowdowns	Vented	16,324	16,324	11,313	**(30.7%)**	BP 3 - Pressure Reduction Policy BP 4 - Project Scheduling Policy BP 5 - Methane Evacuation Procedure BP 6 - Methane Evacuation Work Order Policy BP 7 - Bundling Work Policy BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Emissions	Vented	--	86,681	80,319	**(7.3%)**	BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Component Leaks	Fugitive	10,574	75,957	5,341	**(93.0%)**	BP 22 - Pipe Fitting Specifications BP 23 - Minimize Emissions from Operations, Maintenance and Other Activities
	Dehydrator Vent Emissions	Fugitive	6,761	13	0	**(100.0%)**	n/a
Unusual Large Leaks			N/A		0	-	-

Table 4 - Total Emissions Comparing 2015 & Adjusted Baseline with RY 2022 Emissions	
Approved Adjusted 2015 Baseline (Mscf)	2,204,823
2022 Total Annual Volume of Leaks & Emissions (Mscf)	1,490,564
Year Over Year Comparison with Adjusted Baseline	32.4%

Table 4 above shows the 2015 Baseline Emissions vs. the RY 2022. The year-over-year (YOY) comparison with the approved adjusted 2015 baseline has a reduction of 32.4 percent.

As noted above, PG&E has achieved the 20 percent by 2025 emission reduction compliance goal. Table 5 portrays estimated emission levels by measure in 2022 and 2030. The Cost Effectiveness from Part 5b is discussed in greater detail in each Chapter. PG&E continues to refine areas for estimation and quantifying emissions.

Table 5. Emissions Level Estimate, MCF, Year End (EY 2022)								
					Cost Effectiveness Part 5b $/MSCF			
Measure (Chapter No.)	**2022 Emission Reduction, MCF**	**2022 % Reduc.**	**2030 Emission Reduction, MCF**	**2030 % Reduc.**	**Standard Cost Effectiveness ($/MCF)**	**Standard Cost Effectiveness including Cap & Trade Cost Benefits ($/MCF)**	**Standard Cost Effectiveness Calculation including Social Cost of Methane Benefits ($/MCF)**	**Notes**
1) Non-Emergency Gas Transmission Blowdown Reduction (Chapter 3)	191,906	9%	265,043	12%	$34	$32	$7	No cost is seen when lowering system pressure.
2) Gas Distribution Leak Surveys (Chapter 7) - Accelerated Leak Survey	not provided, this is dependent on the repairs				$49	$47	$23	Using 2023-2025 cost forecasts to calculate the cost per unit, then compare the costs of 5-year and 3-year surveys.
3) Find It /Fix It (Chapter 11) - Distribution M&S	178,954	8%	264,901	12%	$32	$30	$5	SE Program with 10 scfh threshold, 105 SE leak repairs. Based on 2022 SE LS costs and average leak repair cost $10k/unit.
					$29	$26	$2	SE program with 7 scfh treshold, assuming 500 SE leak repairs. Based on 2022 SE LS costs and average leak repair cost $10k/unit.
					$276	$274	$249	2022 belowground grade 3 leak repairs. Based on 2022 belowground grade 3 leak repair data, average leak repair cost $10k/unit.
4) Find It /Fix It (Chapter 11) - Meter Set Assemblies	-4,538	-0.2%	30,738	1%	$41	$38	$14	Based on reduction estimate for prioritizing Class A and B Meter Set Leaks for repair.
5) Above Ground Leak Survey (Chapter 9) - Quarterly CARB Leak Surveys	81,945	3.7%	81,945	3.7%	$69	$67	$43	Based on 2023 GRC forecast and using 2015 adjusted Baseline (to account for 10k to 1k ppm threshold decrease).
6) Damage Prevention (Chapter 14)	166,807	7.6%	166,807	7.6%	$77	$75	$50	Uses 2015 as the baseline and comparing against 2022 emissions for both Transmission and Distribution Damages.
7) Other - includes Improvement in reporting practices, studies to better characterize emissions, remove/replace emitting devices, etc.	99,185	4.5%	174,487	8%				Primary contributor for 2030 goal: R&D Projects (Chapter 15) - Transmission M&R Stations
TOTAL	**714,259**	**32%**	**983,920**	**45%**				

Each Chapter in this 2024 Compliance Plan describes a proposed Measure that consists of a Best Practice or a combination of Best Practices. Table 6 below is the table of concordance for Best Practices.

Table 6 – Table of Concordance for Best Practices

BP #	Chapters Addressing this BP, or Exempt
1	Chapter 1, Compliance Plan
2	Chapter 2, Methane GHG Policy
3 – 7	Chapter 3, Non-Emergency Gas Transmission Blowdown Reduction
8	Chapter 4, Emergency Procedures
9	Chapter 5, Recordkeeping
10 -14	Chapter 6, Gas Training
15 - 16	Chapter 7, Gas Distribution Leak Surveys
17 - 18	Chapter 8, Methane Detection
19	Chapter 9, Aboveground Leak Survey
20a	Chapter 10, Quantification and Geographic Tracking Chapter 15, R&D Projects
20b	Chapter 10, Quantification and Geographic Tracking
21	Chapter 11, Find It/Fix It
22	Chapter 12, Pipe Fitting Specifications
23	Chapter 3, Non-Emergency Blowdown Reduction Chapter 13, High-Bleed Pneumatic Device Replacements Chapter 15, R&D Projects
24-26	Chapter 14, Damage Prevention

SECTION B. CHAPTERS DESCRIBING MEASURES

The chapters below describe each proposed Measure. PG&E created 15 Measures that address one or more Best Practices. Some Best Practices may be addressed by more than one Measure. Per guidance from the CPUC, each Chapter will detail the following information.

<u>Part 1. Evaluate the Current Practices Addressed in this Chapter</u>

a) List the BP(s) addressed by this Chapter including their descriptive text
b) Assess the effectiveness of existing measures related to the BP(s) addressed in this chapter:
    1. What emission reduction do you attribute to this practice compared to the 2022 estimated reduction? What further reductions are expected?
    2. In terms of the utilities' own 2022 Compliance Plan cost effectiveness method, how does the actual cost effectiveness compare with the estimate?
    3. What is the cost effectiveness based on the definition in 5 below?

<u>Part 2. Proposed New or Continuing Measure</u>

Proposed Plan. Discuss the following, as applicable/appropriate.

1. Overlap with other statutory regulations? What part of the Measure is incremental beyond those regulations?

2. What technology is proposed to implement the measure and why?
3. Will the work require additional personnel and/or contract support? Provide details.
4. What changes to existing operations are required? How will those changes be implemented?
5. What changes to, or new procedures, are required?

a) Timeline for Implementation including training on new procedures.
b) Overlap with Other Measures in the Compliance Plan (if any)
c) If the Measure will be addressed with R&D or pilot projects, reference them in the Chapter and describe them in the Appendix according to the R&D template.

Part 3. Abatement Estimates

This part will describe anticipated emissions reduction from the Measure as compared to the 2015 Baseline Emissions as established at the time the Plan is filed. Where known, state which emissions category, source, and classification in the Emissions Inventory is affected as a result of the proposed Measure. Provide supporting calculation methodology.

Part 4. Cost Estimates

This part will provide cost estimates of the proposed Measures to support Cost Effectiveness calculations as required in Decision D.19-08-020. List direct costs by major categories, such as tools, labor, vehicles, supervision, capital equipment, etc. Determine net cost by subtracting quantifiable benefits. Show loaded costs and calculate the average annual revenue requirement from the net loaded cost.

When possible, subtract avoided costs to the utility such as:

- Value of natural gas saved;
- Future reduced leak repair costs;
- Reduced gas lost to leakage;
- Shifting from emergency to planned work;
- Safety improvements;
- System reliability improvements; and
- Lower insurance costs.

Average Annual Revenue Requirement

Revenue requirement represents how the cost to the utility is passed on to customers, so it is the best indicator of costs for the purpose of evaluating ratepayer-funded activities.

From comments cited in the Decision, page 26: The average annual revenue requirement (AARR) is generated by calculating the cumulative revenue requirement for activities that directly contribute to emissions reductions. The activity costs used to calculate the revenue requirement include the fully loaded and escalated capital investment and associated operation and maintenance (O&M), including on-going O&M over the useful life of the related capital asset, if applicable. The cumulative revenue requirement is then divided by the total years of useful life to generate an average annual revenue requirement. This annual revenue requirement can be multiplied by the number of years in the Compliance Plan period. The annual revenue can then be compared to the emissions reductions for the same number of years.

Part 5. Cost Effectiveness/Benefits

Pursuant to Decision D.19-08-020, the cost effectiveness of the proposed measure is calculated by determining the ratio of net cost to the total emissions reduction, where net cost is the average annual revenue requirement, developed in Part 4, less all reasonably quantifiable benefits.

a) Determine the standard cost effectiveness as the ratio of net cost to volume of methane reduced, dollars per MSCF, for the same period.

$$\frac{AARR - Cost\ Benefits}{Emissions\ Reductions}$$

b) The same cost effectiveness calculation as a), with the cost benefit of avoided Cap-and-Trade costs included per D.19-08-020.

$$\frac{AARR - Cost\ Benefits - Avoided\ Cap \,\&\, Trade\ Cost}{Emissions\ Reductions}$$

c) The same cost effectiveness calculation as b), with the avoided social cost of methane included per D.19-08-020.

$$\frac{AARR - Cost\ Benefits - Avoided\ Cap \,\&\, Trade\ Cost - Social\ Cost\ of\ Methane}{Emissions\ Reductions}$$

The cost benefit values utilized in the 2024 Compliance Plan are as follows:

1. The cost benefit of reduced gas was calculated using the forecasted average annual Weighted Average Cost of Gas (WACOG) from the 2018 California Gas Report of $2.42/MCF and adjusting it for inflation to $3.04/MCF (applying a 1.257 California Consumer Price Index[2]).
2. The avoided Cap-and-Trade cost is $2.28/MCF. This value was calculated by taking the Auction Settlement Price from the California-Quebec Joint Auction Settlement Prices and Results published by CARB from February 2024 of $41.76/MTCO2e and applying the conversion factor from D.15-10-032.
3. Per written guidance from the CPUC Safety Policy Division on November 21, 2023, using the D.19-08-020 estimate for 2020 of $21/MCF and applying the California Consumer Price Index, a $24.42 social cost of methane was calculated.

If choosing to combine Best Practices, this section will include the holistic costs of the measure. which will provide a clearer picture of the costs of the proposal.

Cost effectiveness/benefits will be discussed at the measure level, where applicable.

[2] California Department of Industrial Relations. "California Consumer Price Index." https://www.dir.ca.gov/OPRL/CPI/EntireCCPI.PDF.

Part 6. Supplemental Information/Documentation

If the Measure has any supporting documentation, it will be noted and listed in Section C.

CHAPTER 1: COMPLIANCE PLAN

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E submitted its 2022 Compliance Plan as an attachment to its 2022 Gas Safety Plan on March 15, 2022. On September 12, 2022, CPUC SPD approved the 2022 Leak Abatement Program Compliance Plan. The 2022 Compliance Plan summarized the actions taken in the 2022 Compliance Plan period (i.e., 2022 and 2023) to comply with the 26 Best Practices set forth in the Decision Approving Natural Gas Leak Abatement Program Consistent with Senate Bill 1371 (D.17-06-015).

a) Best Practice(s) Addressed by this Chapter

Best Practice 1 - Compliance Plan: Written Compliance Plan identifying the policies, programs, procedures, instructions, documents, etc. used to comply with the Final Decision in this Proceeding (R.15-01-008). Exact wording to be determined by the company and approved by the CPUC, in consultation with CARB. Compliance Plans shall be signed by company officers certifying their company's compliance. Compliance Plans shall include copies of all policies and procedures related to their Compliance Plans. Compliance Plans shall be filed biennially (i.e., every other year) to evaluate best practices based on progress and effectiveness of Companies' natural gas leakage abatement and minimization of methane emissions.

b) Effectiveness

No reductions in emissions are directly associated with this measure. This measure is specific to creating a process and not related to activities that reduce emissions.

Part 2. Proposed New or Continuing Measure

The chapters that follow address PG&E's plans to comply with the 26 Best Practices adopted in the Final Decision for the 2024 Compliance Plan period (i.e., 2024 and 2025). PG&E tracks completion of compliance plans in an internal tracking system to enable filing on a biennial basis. This 2024 Compliance Plan is submitted as a separate attachment to the 2024 Gas Safety Plan. In addition, a management review of this plan is performed prior to submission. The details of implementing each Best Practice can be found the subsequent chapters.

Part 3. Abatement Estimates

No reductions in emissions are associated with this measure. This measure is specific to creating a process and not related to activities that reduce emissions.

Part 4. Cost Estimates and Average Revenue Requirement

No costs are associated with this measure.

Part 5. Cost Effectiveness/Benefits

This measure is the Compliance Plan reporting; therefore, emissions reduction cannot be calculated based on this measure.

CHAPTER 2: METHANE GHG POLICY

Part 1. Evaluate the Current Practices addressed in this Chapter

Addressing climate change is integral to PG&E's mission to provide safe, reliable, affordable, and clean energy to its customers. Since 2006, PG&E has maintained a Climate Change Policy that recognizes the challenges posed by climate change, as well as PG&E's commitment to reduce its greenhouse gas emissions and help its customers do the same. On October 27, 2022, PG&E updated its existing Climate Change Policy (ENV-03) to include a specific reference to reducing emissions of methane, a potent GHG released from the operation of natural gas infrastructure, by implementing SB 1371 and SB 1383, which addresses leak abatement and short-lived climate pollutants, respectively.

a) Best Practice(s) Addressed by this Chapter

Best Practice 2 – Methane GHG Policy: Written company policy stating that methane is a potent GHG whose emissions to the atmosphere must be minimized. Include reference to SB 1371 and SB 1383. Exact wording to be determined by the company and approved by the CPUC, in consultation with CARB, as part of Compliance Plan filing.

b) Effectiveness

This measure requires the implementation of a company policy addressing methane emissions. PG&E updated its existing Climate Change Policy to put focus on methane emissions, consistent with the Best Practice requirement. No reductions in emissions are associated with this measure. This measure is specific to creating a process and not related to activities that reduce emissions

Part 2. Proposed New or Continuing Measure

No additional changes will be needed for the 2024 Compliance Plan period.

Part 3. Abatement Estimates

Not applicable as this measure updates an existing Company policy with the required language in compliance with Best Practice 2.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Compliance with Best Practice 2 is complete, and no additional action is anticipated for the 2024 Compliance Plan period. Therefore, no additional funding is required.

Part 5. Cost Effectiveness/Benefits

This measure is the implementation of a Company-wide policy; therefore, emissions reduction cannot be calculated based on this measure.

CHAPTER 3: NON-EMERGENCY GAS TRANSMISSION BLOWDOWN REDUCTION

To meet sustainability goals and comply with SB 1371 and SB 1383, PG&E developed a standard and procedure (TD-5601S and TD-5601P-01) to reduce methane emissions as much as possible during non-emergency gas transmission blowdowns while maintaining the safety and reliability of PG&E's gas system. This standard provides direction to:

- Assess planned gas transmission system construction projects with sufficient lead time to incorporate emission reduction strategies, including project bundling, drafting, cross compressing and flaring;
- Reduce pressures of transmission isolation areas to lowest operationally feasible levels to minimize the venting of methane;
- Document significant factors considered in methane abatement decisions for all planned transmission projects;
- Calculate all transmission blowdown and reduction amounts for all scheduled projects;
- Accelerate leak detection and repairs where feasible and employ methane reduction strategies in making associated transmission system repairs; and
- Complete a post-blowdown evaluation and analysis after blowdown events with a chamber volume exceeding 50 cubic feet (cf), which is consistent with EPA's 40 CFR Part 98 greenhouse gas ("GHG") reporting requirements.

The post-blowdown evaluation includes the following information: methane emission reduction strategy used, total volume of gas released, total volume of gas abated, a comparison of the planned ending pressure prior to blowdown and the actual ending pressure following the blowdown, and if the actual ending pressure is higher than the planned ending pressure, the reason for the variance. PG&E may choose to modify what type of information is collected for the post-blowdown evaluation as this process is further developed.

PG&E continues to train transmission Gas Operations' employees to provide awareness of the following:

- PG&E's commitments to reduce methane emissions as much as feasible during non-emergency gas transmission blowdowns;
- Roles and responsibilities outlined in TD-5601 guidance documents; and
- The goals and requirements of new Greenhouse Gas Feasibility Assessment.

Refresher training was provided to all transmission project managers and project engineers as they both have critical roles in evaluating the feasibility of incorporating methane emission reduction strategies into projects that require gas blowdowns.

a) Best Practice(s) Addressed by this Chapter

Best Practice 3 – Pressure Reduction Policy: Written company policy stating that pressure reduction to the lowest operationally feasible level in order to minimize methane emissions is required before non-emergency venting of high-pressure distribution (above 60 psig), transmission and underground storage infrastructure consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Exact wording to be determined by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

Best Practice 4 – Project Scheduling Policy: Written company policy stating that any high pressure distribution (above 60 psig), transmission or underground storage infrastructure project that requires evacuating methane will build time into the project schedule to minimize methane emissions to the atmosphere consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Projected schedules of transmission or underground storage infrastructure work, requiring methane evacuation, shall also be submitted to facilitate audits, with line venting schedule updates to be determined. Exact wording to be determined by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

Best Practice 5 – Methane Evacuation Procedure: Written company procedures implementing the BPs approved for use to evacuate methane for nonemergency venting of high pressure distribution (above 60 psig), transmission or underground storage infrastructure and how to use them consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Exact wording to be determined by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

Best Practice 6 – Methane Evacuation Work Order Policy: Written company policy that requires that for any high pressure distribution (above 60 psig), transmission or underground storage infrastructure projects requiring evacuating methane, Work Planners shall clearly delineate, in procedural documents, such as work orders used in the field, the steps required to safely and efficiently reduce the pressure in the lines, prior to lines being vented, considering alternative potential sources of supply to reliably serve customers. Exact wording to be determined by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

Best Practice 7 – Bundling Work Policy: Written company policy requiring bundling of work, whenever practicable, to prevent multiple venting of the same piping consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Company policy shall define situations where work bundling is not practicable. Exact wording to be determined by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

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

b) Effectiveness

In 2022, PG&E abated 82 percent of the total gas volume from transmission pipeline and regulator station projects (Table 7 below). In 2023, PG&E abated 85 percent of the total gas volume from transmission pipeline and regulator station projects (Table 8 below). PG&E diverted a total of 942 MMscf of methane from being blown to atmosphere between 2022 and 2023.

Table 7 - 2022 Transmission Pipeline and Regulator Station Abatement Activities	
Pipeline Activity Type	**Total Gas Volume (mscf)**
Drafting	145,911
Cross-Compression	399,226
Clearance Sharing	36,133
Total Gas Abatement	581,271
Blowdown	127,000
Percent Abatement	**82%**

Table 8 - 2023 Transmission Pipeline and Regulator Station Abatement Activities	
Pipeline Activity Type	**Total Gas Volume (mscf)**
Drafting	40,467
Cross-Compression	243,919
Combustion	59,775
Clearance Sharing	17,127
Total Gas Abatement	361,288
Blowdown	63,746
Percent Abatement	**85%**

PG&E purchased two gas-driven mobile fill compressors and a CNG storage trailer, which allows PG&E to use mobile compression to target smaller blowdowns and pipelines that do not have an adjacent pipeline to cross compress into. PG&E continues to utilize 8 multi-stage/boost compressors to further reduce the amount of gas released during backbone transmission pipeline blowdowns. These multi-stage/boost compressors are rated for a larger pressure differential which allows draw-down to lower pressures than reciprocating compressors. PG&E updated internal procedure to lower the volume threshold of projects to be considered for cross compression. This ensures that the projects with the largest GHG emission potential are appropriately targeted.

PG&E purchased two enclosed combustion devices and two thermal oxidizers, which allows PG&E to handle large pipeline volumes and achieve a better combustion efficiency when compared to existing flaring technologies. PG&E also rented additional enclosed combustion for improved throughput on high-pressure, large diameter systems. PG&E recently improved the flaring documentation process to capture the volume of gas combusted from gas odor fade operations and special in-line inspection operations.

In 2021, PG&E completed the project bundling analysis and has incorporated project bundling as an abatement technique to reduce emissions. Internal procedures promote project clearance consolidation to reduce the number of required outages. PG&E recently improved the project bundling documentation process to capture O&M activities alongside project driven work.

Part 2. Proposed New or Continuing Measure

The Greenhouse Gas Emissions Reduction Standard and associated procedure meets the intent of Best Practices 3 through 7. PG&E will continue to utilize these documents in the 2024 Compliance Plan period and updates may be made pending results of post-blowdown evaluations that are conducted.

To further support Best Practice 23, in 2024 and 2025, PG&E plans to pursue the following to further reduce methane emissions from planned transmission blowdowns:

1. PG&E will now consider methane abatement strategies for station projects. PG&E will expand the GHG feasibility assessment to station categories, including Transmission M&R Stations, Compressor Stations, and Storage Facilities.

2. PG&E continues to evaluate the use of degassing technology on ILI tool load & unloading blowdowns to determine if a technology can be expanded to further reduce methane emissions from other activities, such as smaller volume local transmission projects and station maintenance. If it is determined that a technology is cost and time effective, PG&E will incorporate this technology into existing processes and procedures. This may require purchase of additional equipment or contract support as well as changes to existing operations.

3. PG&E will update project clearance procedures to require a methane abatement strategy for scheduled transmission pipeline blowdowns that expect to blowdown more than 1 MMscf of gas to atmosphere. This will increase the amount of methane abatement activities, thus reducing emissions.

4. PG&E plans to review and analyze pipeline repair projects that utilize a pressure control fitting, a repair sleeve, or hot-taps. The purpose of this review is to determine the amount of gas abated by applying a repair technique that does not require a blowdown.

Part 3. Abatement Estimates

Abatement feasibility and effectiveness highly depends on the nature of the work and the type of assets. Typically, maintenance work, such as valve replacement and hydrotest, has a larger potential for emissions compared to in-line inspections that require only limited blowdown. Large backbone transmission pipelines present better abatement potential than local transmission pipelines because of their larger volume and pressure. As seen in Table 7 & Table 8 the portfolio of work varies from year to year in term of assets and nature of the work. Relative to the 2015 baseline, 2022 and 2023 emissions were down 64 percent and 82 percent.

PG&E is targeting an annual abatement of 90 percent of potential gas releases from backbone pipeline clearances, and 75 percent of potential gas releases from local transmission pipeline clearances.

Part 4. Cost Estimates and Average Annual Revenue Requirement

The proposed actions for this measure during the 2024 Compliance Plan period are forecast through PG&E's 2023 GRC rate case[3] and no additional funding is being requested. These forecasted values are for the capital and expense LNG/CNG programs that support emission reduction efforts.

2024
LNG/CNG Cross-Compression Program: $7.0 million

2025
LNG/CNG Cross-Compression Program: $7.1 million

Part 5. Cost Effectiveness/Benefits

The primary costs associated with this measure is the cost of the cross-compression program, which accounts for about 75% of all gas mitigation on the transmission system. Compared to the 2015 Baseline, PG&E reduced methane emissions by 191.9 MMCF in 2022. The annual 2024-2025 net cost for the program is $6.5 million. Dividing this cost by the emissions reduction leads to a standard cost effectiveness value of $33.86/MCF. Including the cost benefits from Cap-and-Trade and the social cost of methane, the cost effectiveness becomes $7.16/MCF.

[3] A.21-06-021, Exhibit (PG&E-3), p. 5-61, Table 5-20, line 1 and A.21-06-021, Exhibit (PG&E-3), p. 5-70, Table 5-25, line 1

CHAPTER 4: EMERGENCY PROCEDURES

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E performs regular maintenance on its system and has procedures in place to minimize and support the prevention of uncontrolled release of methane. In addition, PG&E's Gas Emergency Response Plan (GERP) addresses how the company responds to emergencies, including loss of containment from the gas system or storage facility. Although PG&E relies on multiple layers of protection to prevent the loss of containment of natural gas, when releases do occur, PG&E is prepared to respond. PG&E reviews and updates the GERP on an annual basis.

a) Best Practice(s) Addressed by this Chapter

Best Practice 8 – Company Emergency Procedures: Written company emergency procedures which describe the actions company staff will take to prevent, minimize and/or stop the uncontrolled release of methane from the gas system or storage facility consistent with safe operations and considering alternative potential sources of supply to reliably serve customers. Exact wording to be determined by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

b) Effectiveness

Cost effectiveness was not calculated in the 2024 Compliance Plan. Emissions reductions are directly associated with the length of time a leak remains open. Any improvement in the average gas shut in time will directly impact the emissions reduction by reducing the amount of time the leak stays open.

Part 2. Proposed New or Continuing Measure

PG&E will continue to utilize its GERP to comply with the Best Practice. No additional actions will be taken.

Part 3. Abatement Estimates

Emissions reductions cannot be directly measured through implementation of its GERP. However, improvements in shut in the gas performance will reduce the amount of time that a leak, resulting from emergency situations, remain open. Emissions reduction from PG&E's Damage Prevention programs, which address dig-ins, are reported annually through the Natural Gas Leakage Report for the Leak Abatement OIR.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Compliance with Best Practice 8 is complete, and no additional actions will be required for the 2024 Compliance Plan period.

Part 5. Cost Effectiveness/Benefits

This measure is the review and update of PG&E's emergency procedures; therefore, emissions reduction cannot be calculated based on this measure. There are also no incremental costs associated with the review and update of PG&E's GERP.

CHAPTER 5: RECORDKEEPING

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E's records management is governed by PG&E Corporation Standard GOV-7101S, Enterprise Records Information Management Standard. This Standard establishes requirements for records and information, roles, and responsibilities for managing and governing records and information at PG&E Corporation and its subsidiaries, including Pacific Gas and Electric Company (together, PG&E). The Standard applies to records and information created, modified, maintained, stored/archived, retrieved, transmitted, and disposed during the course of PG&E business, regardless of format. The Standard also provides the retention schedule for all PG&E records at the highest level (record category).

Currently, the SB 1371 Annual Emissions Inventory Reports are "Regulatory Records" as they are filed annually pursuant to the Leak Abatement OIR proceeding. To comply with this Best Practice, the retention code is REG0210 Regulatory – CPUC Permanent. Therefore, these records will be retained for the life of the Company.

a) Best Practice(s) Addressed by this Chapter

Best Practice 9 – Recordkeeping: Written Company Policy directing the gas business unit to maintain records of all SB 1371 Annual Emissions Inventory Report methane emissions and leaks, including the calculations, data and assumptions used to derive the volume of methane released. Records are to be maintained in accordance with General Order (GO)112-F and succeeding revisions, and 49 CFR 192. Currently, the record retention period in GO 112-F is at least 75 years for the transmission system. 49 CFR 192.1011 requires a record retention period of at least 10 years for the distribution system. Exact wording to be determined by the company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing.

b) Effectiveness

This measure addresses recordkeeping, which does not directly reduce emissions. Therefore, there are no emission reductions associated with recordkeeping requirements.

Part 2. Proposed New or Continuing Measure

Compliance with Best Practice 9 has been fulfilled; therefore, no additional actions are required for the 2024 Compliance Plan period.

Part 3. Abatement Estimates

No reductions in emissions are associated with this measure. This measure is specific to creating a process and not related to activities that reduce emissions.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Compliance with Best Practice 9 is complete, and no additional actions are required.

Part 5. Cost Effectiveness/Benefits

This measure relates to recordkeeping; therefore, emissions reduction cannot be calculated based on this measure.

CHAPTER 6: GAS TRAINING

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E currently utilizes a talent requisition site to provide guidance on hiring both union and non-union employees. This allows for leaders to work with Human Resources and Labor Relations (as applicable) to create job openings, define the classification of the job, and look for candidates with existing qualifications and/or prior experience. This process also provides leaders with the support needed to make updates to existing classifications. Furthermore, gas employees whose work can affect methane emissions and leak abatement will be required to take the requisite trainings as described below.

Existing Gas Training Practices

PG&E's Human Resource Department develops technical training materials required to maintain a skilled, safe, and qualified workforce. The Gas Training Curriculum Program focuses on developing an up-to-date curriculum that reflects current procedures and regulations, properly introducing and reinforcing safety requirements.

The drivers for curriculum development include:

- Regulatory requirement-driven updates to work procedures
- Facilitating knowledge transfer from employees exiting the workforce to those entering
- Emergent technologies and processes
- Changes to work procedures.

The scope of the curriculum developed is informed by business needs. Curriculum development priorities are set through the Gas Training Governance (GTG)[3] process that delivers accountability, transparency, and oversight, in conjunction with the supporting guidance documents and qualifications that align to the Gas Operations Risk Register and the Corrective Action Program.

The following Operator Qualifications (OQ) and courses, among others, support PG&E's efforts to reduce greenhouse gas emissions and these Best Practices.

Operator Qualifications

- OQ-0805 Aerial Leak Survey by Drone
- OQ-0901 Conduct Survey
- OQ-0902 Leak Investigation

[3] The GTG is a cross-functional team of gas operations personnel from the International Brotherhood of Electrical Workers and management across several departments that hear business cases brought forth by organizations that are requesting the development of new gas curriculum at PG&E Academy. This team evaluates requests to develop new curriculum. The team's primary function is to use their knowledge and experience to determine: if the business case is well considered, the submitter has a way to measure the planned improvement in business objectives, that the request is in alignment with Gas Operations priorities (risk, initiatives, etc.), and that the stakeholder (student) analysis is complete.

- OQ-0903 F.S. Leak Inv/Leak Grading
- OQ-0908 F.S. Leak Grading
- OQ-0911 Conduct Mobile Picarro Leak Survey
- OQ-0912 Conduct Mobile Leak Survey

Trainings

- **Gas-0207 Leak Survey Detection & Grading:** Leak survey detection and grading presents an overview of the leak survey process and reviews the current gas standards, guidelines, and bulletins that apply to the leak survey. The student will inspect, calibrate, and perform minor maintenance on various leak survey instruments. He/She will perform leak survey, grading, and complete associated documentation per established standards, guidelines, and bulletins.
- **Gas-0214 Leak Survey Refresher:** The course provides "refresher" instruction on conducting a leak survey, and a review of the most currently updated leak survey procedures. This training is designed to prepare you to conduct a leak survey in alignment with all PG&E standards and procedures.
- **GAS-0306 Leak Investigation & Pinpointing:** The goal of this course is to train PG&E employees to follow a systematic approach for investigating and pinpointing gas leaks in accordance with work procedure TD-5100P-02 Subsurface Leak Investigation and Pinpointing for Repair.
- **GAS-9642 Mobile Leak Survey:** Leak surveyors learn how to safely operate, test, and maintain an Optical Methane Detector device, as well as the DP-IR mobile vehicle. In addition, they learn how to plan their route, prepare, install, inspect, maintain, and perform a leak survey with a Detecto-Park Mobile Unit and complete the end of use steps for the unit.
- **Gas Emergency Response Plan (GERP) Training**: PG&E's Gas Emergency Preparedness training consists of three GERP courses as follows:

  - Gas-9121 GERP Awareness: This course provides general awareness-level information for the GERP and is intended for all Gas employees (except Field Responders and Emergency Center staff) and shared services agencies that support Gas Operations.
  - Gas-9122 GERP Response Training: This course defines the role of PG&E field responders as well as the necessary activities to activate and maintain the Emergency Response Process.
  - Gas-9123 GERP Emergency Center (Instructor Led Training): This course provides training on the changes to the GERP, as well as the participants' role in responding to or supporting a gas emergency using the Incident Command System.

These trainings are updated and assigned to designated employees on an annual basis.

Gas Safety Academy

The Gas Safety Academy in Winters, California opened in 2017. This facility has become the primary training center for employees learning to operate and maintain every aspect of PG&E's natural gas infrastructure. It features the latest in training technologies, including heavy equipment simulators, virtual learning resources, a model neighborhood for emergency response and leak detection practices, and educational programs on industry-leading safety protocols.

The Gas Safety Academy consists of a learning center and utility village. The Learning Center is the primary technical training center that includes classrooms, labs, M&C tech center (e.g., the Indoor Flow Lab wherein compressed air is used to simulate natural gas flow), and a gas service representative (GSR) area, where GSRs will be trained in customer service including, meters, leak detection and service inspections. The Utility Village is a small-scale replica of a residential neighborhood used to train field service representatives on customer interface, leak detection, location and marking of existing pipelines, and emergency response scenario training.

The Gas Safety Academy utilizes compressed air in the Gas Pipeline Operations & Maintenance flow lab, gas chromatograph room, as well as the Field Services lab for service mechanic training. Utilization of compressed air versus natural gas provides a zero-gas emission training environment and allows our students to safely and quickly perform routine maintenance on simulated distribution and transmission regulation equipment. In addition, allowing our student population to train and perform rotary meter operations such as differential testing, flange, and gasket installation/removal, in addition to complete meter removals, allow for comprehensive training without the need to exhaust natural gas to atmosphere.

Regarding operations and maintenance of multiple distribution and transmission regulation stations and associated gas measurement equipment (ERX, SCADA, Total-Flow, Becker controllers, etc.), students and lab operators are able to remove components on the gas system and allow students to perform inspections normally performed in the field without the need to exhaust natural gas to atmosphere.

An additional benefit of utilizing the flow lab is that we can install new technology or gas regulation component that requires testing and "proof of concept" operation prior to introducing the product in the field with unlimited attempts to fill/evacuate the pipeline with compressed air versus natural gas. The quantity of natural gas emissions avoided by utilization of compressed air is almost incalculable.

a) Best Practice(s) Addressed by this Chapter

Best Practice 10 - Minimize Uncontrolled Natural Gas Emissions Training: Training to ensure that personnel know how to use company emergency procedures which describe the actions staff shall take to prevent, minimize and/or stop the uncontrolled release of natural gas from the gas system or storage facility. Training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's General Rate Case (GRC) and/or Collective Bargaining Unit (CBU) processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.

Best Practice 11 - Methane Emissions Minimization Policies Training: Ensure that training programs educate workers as to why it is necessary to minimize methane emissions and abate natural gas leaks. Training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or CBC processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.

Best Practice 12 - Knowledge Continuity Training Programs: Knowledge Continuity (Transfer) Training Programs to ensure knowledge continuity for new methane emissions reductions best practices as workers, including contractors, leave and new workers are hired. Knowledge continuity training programs to be designed by the Company and approved by the CPUC, in consultation with CARB, as part of the Compliance Plan filing. If integration of training and program development is required with the company's GRC and/or CBC processes, then the company shall file a draft training program and plan with a process to update the program once finalized into its Compliance Plan.

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

Best Practice 14 - Job Classifications: Create new formal job classifications for apprentices, journeyman, specialists, etc., where needed to address new methane emissions minimization and leak abatement best practices, and filed as part of the Compliance Plan filing, to be approved by the CPUC, in consultation with CARB.

b) Effectiveness

There were no emissions reductions anticipated from Gas Operations training that support the Best Practices mentioned above. Therefore, cost effectiveness is not applicable.

<u>Part 2. Proposed New or Continuing Measure</u>

PG&E will continue using its existing Gas Operations training plan and curriculum development/updates to support these Best Practices. No additional or incremental work is being proposed for the 2024 Compliance Plan period.

PG&E will utilize its historic work as described above in Part 1 to address any new classifications that are required. Current job classifications adequately address necessary skills and training for employees whose work can affect methane emissions and leak abatement. At this time, PG&E does not anticipate any new classifications to be created for methane emissions minimization or leak abatement in 2024 and 2025. Therefore, compliance with Best Practice 14 is complete.

Part 3. Abatement Estimates

Emissions reductions cannot be measured from training classes.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Gas Operations training does not directly contribute to emissions reductions. Annual revenue requirements for all planned gas training (including those listed above) were forecasted in PG&E's 2023 GRC. For 2024, the Gas Operations training adopted expenditures are approximately $10.5 million.[4] For 2025, the Gas Operations training adopted expenditures are approximately $10.8 million.[5] There is no incremental funding required to comply with these Best Practices.

Part 5. Cost Effectiveness/Benefits

This measure is the implementation of training and programs through Gas Operations Training; therefore, emissions reductions cannot be calculated based on this measure.

[4] PG&E's 2023 GRC Exhibit (PG&E-8), Chapter 6, WP 6-11. Note, the adopted dollars provided include all of Gas Operations training, and not just training to support methane emissions reduction.
[5] PG&E's 2023 GRC Exhibit (PG&E-8), Chapter 6, WP 6-11. Note, the adopted dollars provided include all of Gas Operations training, and not just training to support methane emissions reduction.

CHAPTER 7: GAS DISTRIBUTION LEAK SURVEYS

Part 1. Evaluate the Current Practices Addressed in this Chapter

In 2023, PG&E performed gas distribution leak surveys on a three-year leak survey cycle in order to comply with this Best Practice. PG&E performs its gas distribution leak surveys with traditional foot surveys.

In 2022-2023, PG&E continued to perform additional leak surveys on selected vintage pipes on distribution assets. The material focus of the special leak survey is pre-1940 steel and pre-1975 plastic vintages. PG&E has incorporated the vintage pipe leak survey into the DIMP leak surveys and funding for this work was adopted in the 2023 GRC decision.[6]

a) Best Practice(s) Addressed by this Chapter

Best Practice 15 – Gas Distribution Leak Survey: Utilities should conduct leak surveys of the gas distribution system every 3 years, not to exceed 39 months, in areas where GO 112-F, or its successors, requires surveying every 5 years. In lieu of a system-wide three-year leak survey cycle, utilities may propose and justify in their Compliance Plan filings, subject to Commission approval, a risk-assessment based, more cost-effective methodology for conducting gas distribution pipeline leak surveys at a less frequent interval. However, utilities shall always meet the minimum requirements of GO 112-F, and its successors.

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

b) Effectiveness

The three-year leak survey cycle enables PG&E to detect and fix leaks faster than the federal mandate of a five-year leak survey cycle. Therefore, PG&E anticipates a decrease in emissions in subsequent leak survey cycles.

Part 2. Proposed New or Continuing Measure

[6] PG&E's 2023 GRC Exhibit (PG&E-3), Chapter 10, WP Table 10-22

In the 2022 Compliance Plan period, PG&E improved the cost effectiveness for annual vintage leak surveys by leveraging Picarro Super Emitter (SE) drives. Leak survey is traditionally done by foot survey, which is time-consuming. Whereas mobile leak surveys are typically 10 times faster. Since the SE program uses mobile and covers the entire distribution system, we can leverage the SE drives to cover the vintage areas. This reduces the foot survey scope and increases cost-effectiveness.

Picarro performed an analysis of the 2021 SE field of view data and determined that roughly 40 percent of the vintage segments were completely covered by the mobile vehicle. In Q4 2022, PG&E performed a pilot to evaluate the abatement opportunity and cost reduction. Follow-up survey is only conducted on leak indications above the SE threshold and gaps, the area(s) not covered by the car. This method ensures we maximize emission savings by targeting super emitters for detection and repair.

PG&E operationalized this process in 2023 and plans to continue this measure during the 2024 Compliance Plan period.

This Measure overlaps with Best Practices 9, 16, and 17, as these best practices also relate to leak survey scheduling. There will be coordination required to maintain records and to schedule the various surveys happening on different frequencies.

Part 3. Abatement Estimates

Three-year leak surveys enable leak repairs to be conducted at a faster rate than the mandated five-year leak survey cycles. Emissions reductions from gas distribution leak surveys as proposed in this measure are addressed in Chapter 11, Find It/Fix It.

Part 4. Cost Estimates and Average Annual Revenue Requirement

The 2024-2025 cost estimates for Gas Distribution Compliance leak survey, Super Emitter Program, and Annual DIMP Leak Survey are as follows:

Compliance
Traditional Leak Survey: PG&E forecasts to survey approximately 1.4 million services and associated main in both 2024 and 2025 for approximately $17.8 million in 2024 and $18.4 million in 2025.[7]

When calculating cost per unit, the cost to complete the compliance survey on a 5-year cycle would have been 10.9 million [8]. The cost to transition from a 5- year to a 3-year leak survey cycle is an increase in annual cost of approximately $7.2 million.

[7] PG&E's 2023 GRC Exhibit (PG&E-3) Chapter 10, WP Table 10-8.
[8] A.21-06-021, Exhibit (PG&E-3), p. WP 10-5, Table 10-5, lines 3 & 7

Super Emitter Program
PG&E's Super Emitter program has adopted expenditures in the 2023 GRC of approximately $1.51 million in 2024 and approximately $1.54 million in 2025 to perform the super emitter survey.[9]

Annual DIMP Leak Survey
PG&E's DIMP Leak Survey program has adopted expenditures in the 2023 GRC of approximately $0.89 million in 2024 and approximately $0.91 million in 2025 to perform annual DIMP Leak surveys.[10] The DIMP Leak Survey Program is a targeted risk mitigation program that goes beyond and is separate from the leak surveys required by code. Survey areas are identified through the DIMP risk review process, emergent issues such as incidents, and compliance concerns.

<u>Part 5. Cost Effectiveness/Benefits</u>

The emission reduction calculation is based on moving from a 5-year to 3-year survey cycle. This calculation assumes that the leaks are repaired in the year they are found (no backlog) and that the leak growth in plats follows a linear model. The time since last survey is the primary driver of leak growth, therefore the plats with the longer time since previous survey are prioritized. The long-term emissions reduction (steady state) is 33 percent. This 33 percent reduction was applied to the 2016 emissions for found and unknown leaks. The 2016 data was chosen because the leak surveys were conducted on a five-year survey cycle. By applying the 33 percent reduction, the expected reduction in emissions volume is 138,700 Mscf.
The cost effectiveness calculation is the cost difference between 5 to 3-year leak survey (less the value of gas saved), divided by the expected reduction volume, which equals to approximately $49/Mscf. Please note that this cost does not consider the cost of repairs. Once the survey cycle is in the steady state, there is no additional cost for repairs since the survey occurs more frequently and therefore the found leaks would be the same as the steady-state for 5 years.

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[9] PG&E's 2023 GRC Exhibit (PG&E-3) Chapter 10, WP Table 10-14.
[10] PG&E's 2023 GRC Exhibit (PG&E-3) Chapter 10, WP Table 10-22.

CHAPTER 8: METHANE DETECTION

Part 1. Evaluate the Current Practices Addressed in this Chapter

During the 2022 Compliance Plan period, PG&E continued to use advanced mobile and aerial technologies and engaged additional R&D efforts to improve these technologies and discover new ones. PG&E has continued the use of vehicle-mounted methane and ethane detection technology (Picarro Surveyor). Additionally, PG&E has developed new solutions through R&D efforts, including:

- Piloting various continuous monitoring devices & systems at M&R stations, compressor stations & storage facilities
- Exploring satellite leak detection technologies
- Piloting helicopter and drone methane detection and quantification

The CARB Oil and Gas Rule directs compressor and storage facility operators to perform quarterly leak surveys, to repair leaks quickly after discovery, and to install stationary ambient detectors at storage facilities. The rule also requires daily or continuous leak screening at each injection/withdrawal wellhead.

To comply with this regulation, PG&E continued utilizing stationary leak detectors at a small number of facilities to evaluate performance and cost factors of different units before broadly deploying units across its territory. Stationary methane detectors include point detectors with sensitivity varying from part per billion to percent gas, Optical Gas Imaging Systems and Open Path methane detectors. While daily leak surveys are completed at storage facilities, R&D is evaluating the performance of various continuous monitoring devices.

a) Best Practice(s) Addressed by this Chapter

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

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

b) Effectiveness

This measure does not reduce emissions but rather enables PG&E to detect leaks faster than the traditional leak survey tools. By allowing the faster detection of more and smaller leaks from the gas system, this measure leads to methane emission reductions that can be represented by the adjustment of leak-based emissions factors for the utilities implementing this measure. Cost effectiveness was not calculated because the detection of leaks does not provide a direct impact to emission reductions.

Part 2. Proposed New or Continuing Measure

PG&E will continue to implement the current actions related to enhanced methane detection to comply with Best Practice 15. This action uses and explores a broad range of technologies. Refer to Chapter 15 – R&D projects for a list of technologies PG&E is exploring.

Part 3. Abatement Estimates

An abatement estimate cannot be calculated for the advancement of leak detection technologies.

Part 4. Cost Estimates and Average Annual Revenue Requirement

The actions contained in this measure are funded through PG&E's R&D funding mechanisms and in some cases, funding is cost-shared by other utilities through research consortium. Refer to Chapter 15 – R&D projects for the cost estimate and average annual revenue requirement. No incremental funding is required to continue implementation of this measure.

Part 5. Cost Effectiveness/Benefits

Refer to Chapter 15 – R&D projects for the cost effectiveness and benefits.

CHAPTER 9: ABOVE GROUND LEAK SURVEY

Part 1. Evaluate the Current Practices Addressed in this Chapter

In 2017, CARB Oil and Gas rule required operators to perform quarterly leak surveys at compressor stations and storage facilities. These quarterly leak surveys enable leak repairs to be conducted at a faster rate than the annual leak survey cycle. In 2020, the leak threshold for CARB O&G facilities were decreased from 10k to 1k ppm; this resulted in a 264 percent increase of emissions, comparing 2019 to 2020.

PG&E performs leak survey at PG&E's compressor stations, gas storage facilities, city gates and metering & regulating stations. Leak surveys at compressor and storage facilities are completed on a quarterly basis in compliance with the CARB Oil and Gas Rule. Leak surveys at city gates and metering & regulating stations are completed on a semi-annual basis as required by GO 112-F.

a) Best Practice(s) Addressed by this Chapter

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

b) Effectiveness

The mandatory quarterly leak surveys enabled PG&E to detect and repair leaks at a faster rate. As shown in Table 3 in the Introduction, PG&E reported a decrease in fugitive emissions (between 2015 and 2022) associated with leaks at its compressor stations, and underground storage facilities.

Part 2. Proposed New or Continuing Measure

PG&E will continue its existing aboveground leak survey process as required by regulations. No additional actions are proposed to comply with this Best Practice. During the 2024 Compliance Plan period, PG&E will continue to evaluate continuous monitoring technology that can quantify emissions from compressor stations, regulator stations, and wellheads (see Chapter 15: R&D Projects)

In parallel, PG&E will explore new and advanced technologies to detect aboveground leaks including gas imaging cameras, low-cost point sensors, and aerial-based leak quantification technology through R&D projects.

Part 3. Abatement Estimates

The abatement is calculated by subtracting the 2015 adjusted baseline and 2022 emissions, which is 82 MMscf. This emissions reduction is projected to remain the same for 2024-2025 as there is no incremental work planned.

Part 4. Cost Estimates and Average Annual Revenue Requirement

PG&E's CARB Leak Survey program has adopted expenditures in the 2023 GRC of approximately $3.3 million in 2024 and approximately $3.4 million in 2025.[11] PG&E's CARB Leak Repair program has adopted expenditures in the 2023 GRC of approximately $2.6 million in 2024 and approximately $2.7 million in 2025.[12]

PG&E's Ground Leak Survey program has adopted expenditures in the 2023 GRC of approximately $1.01 million in 2024 and approximately $1.04 million in 2025.[13]

No incremental funding is being requested as part of this Compliance Plan.

Part 5. Cost Effectiveness/Benefits

The 2024 cost of the quarterly CARB leak survey and repair program is $5.9 million. The net annual cost, which includes cost savings of gas not emitted by the repairs, is $5.7 million. PG&E estimates the abatement to be 82 MMscf, comparing the 2015 adjusted baseline to the 2022 emissions from compressor stations and underground storage component leaks. Dividing the net annul cost by the emissions reduction the standard cost effectiveness is approximately $69/Mscf. Including the benefits of Cap-and-Trade and the social cost of methane, the cost effectiveness improves to $43/Mscf.

The cost effectiveness/benefit analysis was not performed on aboveground transmission pipelines since the emissions are calculated using a mile-based approach.

[11] PG&E's 2023 GRC Exhibit (PG&E-3) Chapter 10, WP Table 10-64.
[12] PG&E's 2023 GRC Exhibit (PG&E-3) Chapter 10, WP Table 10-65.
[13] PG&E's 2023 GRC Exhibit (PG&E-3) Chapter 10, WP Table 10-58.

CHAPTER 10: QUANTIFICATION AND GEOGRAPHIC TRACKING

Part 1. Evaluate the Current Practices Addressed in this Chapter

Refer to Chapter 7 and 11 for how PG&E leverages mobile technology to quantify emissions through the SE Program.

Refer to Chapter 15 for the R&D projects PG&E is performing to quantify emissions in other emission categories.

Lastly, PG&E developed a centralized, searchable map that shares gas-related emissions data collected between 2020-2022 through its robust system-wide gas emissions survey process. 2023 data will be updated after the June Natural Gas Leak Abatement OIR report filing. The data is tracked and measured to ensure that PG&E can track service-area wide decline in year-over-year gas-related emissions.

a) Best Practice(s) Addressed by this Chapter

Best Practice 20a – Quantification & Geographic Tracking. This best practice states the following: Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan how they propose to address quantification. Utilities shall work together, with CPUC and ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks for the purpose of tracking emissions reductions.

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

b) Effectiveness

No reductions in emissions are directly associated with this measure. This measure is specific to quantification and geographically tracking leaks and not related to activities that reduce emissions.

Part 2. Proposed New or Continuing Measure

PG&E proposes to continue the R&D projects and use the results to refine/establish emission factors and develop new techniques for leak quantification. Refer to Chapter 15 – R&D projects for a list of projects PG&E is performing.

Finally, as stated in Part 1 above, PG&E has published a publicly available geographic map that displays emission information by zip code. PG&E plans to update the data after annual emission reporting is approved.

Part 3. Abatement Estimates

Calculating abatement is not applicable as this measure aims to quantify and geographically track leaks.

Part 4. Cost Estimates and Average Annual Revenue Requirement

The actions contained in this measure are funded through PG&E's R&D funding mechanisms and in some cases, funding is cost-shared by other utilities through research consortium. Refer to Chapter 15 – R&D projects for the cost estimate and average annual revenue requirement. No incremental funding is required to complete the forecasted work.

Part 5. Cost Effectiveness/Benefits

This measure evaluates technologies to enhance PG&E's ability to quantify leaks; therefore, emissions reduction cannot be calculated based on this measure.

CHAPTER 11: FIND IT/FIX IT

Part 1. Evaluate the Current Practices Addressed in this Chapter

In 2023, PG&E moved towards 100 percent emission surveys, decreasing the threshold from 10 scfh to 7 scfh. PG&E currently conducts traditional compliance surveys on a portion of its system each year, and uses leak grades, a methodology which ranks leaks based on risk, for repair and monitoring. The SE survey is performed in addition to existing compliance surveys and prioritizes repairs for leaks with a flow rate of greater than 7 standard cubic feet per hour (scfh). SE surveys cover the portion of the service territory not covered by PG&E's compliance survey.

PG&E continues to fix all Grade 1 and Grade 2 leaks, as required by regulations. In accordance with the Commission's GO 112-F, PG&E repairs all Grade 1 leaks immediately and Grade 2 leaks within 12 months, with a six-month recheck.[14]

In 2022, the CPUC approved PG&E's request in the 2022 Leak Abatement Compliance Plan to reduce the repairs of belowground Grade 3 repairs to 1000.[15]

a) Best Practice(s) Addressed by this Chapter

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

b) Effectiveness

The following summarizes the leak repairs performed during the 2022 Compliance Plan period.

Grade 3 Leak Repair

Table 9 below summarizes the 2024 Compliance Plan actual Grade 3 leak repairs. The table includes both original and pre-repair Grade 3 leaks since some leaks that are initially captured as a Grade 3 may be upgraded at the time of repair and therefore not account anymore as Grade 3 leak repairs.

Table 9 - 2024 Compliance Plan Actual Grade 3 Leak Repairs

	2022		**2023**	
Above or Below Ground?	**Original Grade**	**Pre-Repair Grade**	**Original Grade**	**Pre-Repair Grade**
Above	3,371	3,239	999	967
Below	3,177	2,036	2,057	1,294

[14] General Order 112-F Section 143.2 Leak Classification and action criteria – Grade – Definition – Priority of leak repair at 14-18.
[15] Note, the 2023 GRC Decision adopted 2,000 belowground Grade 3 repairs per year for years 2023-2026.

Please note that the values above are based on a data screenshot at the end of 2023. There may be further data refinements that will be reflected in the reporting year 2023 Natural Gas Leakage Abatement Report.

Super Emitter (SE) Program

In the 2022 Leak Abatement OIR Report, emissions from distribution mains and services leaks totaled 302 MMscf with the SE Program. Without the SE Program, the total emissions would have totaled 395 MMscf. The abatement is the difference between the emissions without the SE program, and the emissions with the SE program, which is 93 MMscf. The number of SEs repaired in 2023 will be provided in PG&E's 2023 Natural Gas Leakage Report for the Leak Abatement OIR.

The following summarizes the effectiveness of the actions taken to comply with Best Practice 21 during the 2022 Compliance Plan period:

Grade 3 Backlog Reduction

Using the 2022 pre-repair Grade 3 leak data, PG&E spent approximately $20 million to repair 2,005 belowground Grade 3 leaks. The net annual cost, which includes cost savings of gas not emitted by Grade 3 repairs, is $13 million. PG&E estimates the abatement from belowground Grade 3 leak repairs to be approximately 19 Mscf per leak.[16] The emission reduction savings from repairing 2,005 belowground grade 3 leaks is 74.2 MMscf. As a result, dividing the total spend in 2022 by the emission reduction savings from repairing 2,005 belowground grade 3 leaks, the cost per Mscf is approximately $276/Mscf.

Super Emitter (SE) Program

In 2022, PG&E spent approximately $1.1 million for 104 super emitter leak repairs. The net annual cost for the program, which includes the SE survey, SE repair, and cost savings not emitted by SE is $2.3 million. PG&E estimates the abatement from SE leak repairs to be approximately 688 Mscf per leak.[17] The emission reduction savings from repairing 104 SE leaks is 72 MMscf. As a result, dividing the net annual cost by emission reduction savings from repairing 104 SE leaks, the cost per Mscf is approximately $32/Mscf for the SE Program.
PG&E's Super Emitter program has adopted expenditures in the 2023 GRC of approximately $1.51 million in 2024 and approximately $1.54 million in 2025 to perform super emitter surveys.[18]

[16] Non-Super Emitter (NSE) emissions is calculated using the EF NSE emission rate of 0.0337 Mscf/day from the 2020 Natural Gas Leakage Report for the Leak Abatement OIR, Appendix 4, Found 2020 LS tab, column AA. The calculation assumes the leak stays open for three years, which is the survey interval.
[17] SE emissions are calculated using the EF SE emission rate of 0.629 Mscf/day from the 2020 Natural Gas Leakage Report for the Leak Abatement OIR, Appendix 4, Found 2020 - LS tab, column AA. The calculation assumes the leak stays open for three years, which is the survey interval.
[18] PG&E's 2023 GRC Exhibit (PG&E-3) Chapter 10, WP Table 10-14.

Meter Set Leak Management

In 2022, PG&E spent approximately $2.8 million for 21,090 meter set leak repairs. The net annual cost, which includes the cost savings of gas not emitted by MSL repairs, is $2.6 million. PG&E estimated the abatement from prioritizing meter set leak repairs to be approximately 65 MMscf[19]. As a result, dividing the net annual cost by emission reduction savings from the scenario above, the cost per Mscf is approximately $41/Mscf for the prioritization of MSL repairs.
PG&E's Meter Set Leak Management has adopted expenditures in the 2023 GRC of approximately $9.8 million in 2024 and approximately $10.1 million in 2025 to perform meter set leak repairs.[20]

Part 2. Proposed New or Continuing Measure

In 2023, PG&E lowered the SE threshold from 10 to 7 scfh. PG&E's 2023 GRC did not request incremental funding for this threshold adjustment. Nevertheless, depending on the emissions reduction results for 2022, PG&E will continue to evaluate decreasing the threshold to meet the abatement goals.

PG&E's BP 21 compliant leak repair program proposal for 2024-2025 is summarized below:

- PG&E will continue fixing all Grade 1 and Grade 2 leaks as required. In accordance with the Commission's GO 112-F, PG&E repairs all Grade 1 leaks immediately and Grade 2 leaks within 12 months, with a six-month recheck.
- PG&E will also find and repair the leaks that emit the highest amounts of methane in the system (the "Super Emitters") at a reduced threshold of 6 scfh in 2024.
- PG&E will continue to repair any below-ground Grade 3 leak that develops into a higher-grade leak consistent with the timelines set forth above and will continue to remove leaks that no longer exist from the monitoring program.
- PG&E will continue to repair all aboveground Grade 3 leaks, including meter set leaks, within 3 years.

Part 3. Abatement Estimates

Based on 2022 leak repair data and assuming that leaks are open for three years, the emissions per SE leak is 688 Mscf and for non-Super Emitters (NSEs), the emissions is 37 Mscf per leak.

[19] The MSL emission calculation assumes a 26% reduction of the 2020 leak-based approach baseline value. The 26% is based on Class A MSL leaks being repaired immediately and Class B MSL leaks are repaired within 6 months. The calculation also assumes the leak stays open for three years, which is the survey interval.
[20] PG&E's 2023 GRC Exhibit (PG&E-3) Chapter 10, WP Table 10-51.

The emissions saved from the repair of one SE leak is equal to the repair of approximately 18.6 NSE leaks.

Reducing SE threshold in 2023, each SE leak repair above 7 scfh is accounted for as 427 Mscf, assuming the leak stays open for 3 years. For 500 leak repairs, the total abatement is approximately 213 MMscf.

Part 4. Cost Estimates and Average Annual Revenue Requirement

No incremental funding is required to complete the forecasted work.

Part 5. Cost Effectiveness/Benefits

As stated in Part 1 above, based on the 2022 leak repair data, the standard cost effectiveness per Mscf (for 2005 belowground Grade 3 leak repair abated emissions over 3 years) is $276/Mscf. The cost effectiveness when considering avoided Cap-and-Trade is $274/Mscf. The cost effectiveness when considering avoided Cap-and-Trade and social cost of methane is $249/Mscf

Based on the 2022 data, SE Program standard cost effectiveness per Mscf is $32/Mscf. With the reduction in threshold from 10 to 7 in 2023, PG&E expects the standard cost effectiveness of $29/Mscf. The cost effectiveness for SE program at 10SCFH when considering avoided Cap-and-Trade is $30/Mscf. The cost effectiveness when considering avoided Cap-and-Trade and social cost of methane is $5/Mscf.

CHAPTER 12: PIPE FITTING SPECIFICATIONS

Part 1. Evaluate the Current Practices Addressed in this Chapter

PG&E has a robust and programmatic system for updating its standards and procedures around pipe fitting specifications which exceed American Society of Mechanical Engineers (ASME) standards. The program includes continuous evaluation of tools, technology, and procedures to address changes in code and compliance.

During the 2022 Compliance Plan period, PG&E published the following guidance documents that references the NPT standard for threads:

- Gas Design Standard F-70 Need and Instrumentation Valves, Manifolds, and Accessories
- Gas Design Standard B-62 Stainless Steel Tube Fittings
- Gas Design Standard B13.5 Stainless Steel Threaded Nipples
- Gas Design Standard B-63 Stainless Steel Threaded Fittings
- Gas Design Standard Honeywell Electronic Corrector with Audit Trail (EC-350/Mini-AT) Data Sheet
- Engineering Material Specification EMS-4125 Trunnion-Mounted Carbon Steel Ball Valves
- Gas Design Standard J-27.15 Rotary Meter Set 56,000 acfh Capacity
- Gas Design Standard J-27.06 Rotary Meter Set 5,000 and 7,000 acfh Capacity
- Gas Design Standard J-27.14 Rotary Meter Set 38,000 acfh Capacity
- Gas Design Standard J-27.12 Rotary Meter Set 23,000 acfh Capacity
- Gas Design Standard J-27.10 Rotary Meter Set 16,000 acfh Capacity
- Gas Design Standard J-27.08 Rotary Meter Set 51,000 acfh Capacity
- Gas Design Standard J-27.02 Rotary Meter Set 1,000, 2,000, and 3,000 acfh Capacity
- Gas Design Standard J-62.6 Installation of Electronic Corrector on Gas Meters
- Gas Design Standard M-42.1 Bypass Hoses
- Gas Design Standard P-60 Compressor and Processing Facility Instrumentation Controls
- Gas Design Standard H-46.1 Fisher 627 Regulators and 634M High-Pressure Shutoff Valve
- Gas Design Standard J-12 Residential (#1A Connection Size) Diaphragm Gas Meter Installation
- Gas Design Standard J-50 Meter Swivels and Swivel Nuts
- Gas Design Standard H-14 Gas Regulator Stations – Spring-Loaded and Pilot-Operated Systems
- Gas Design Standard J-12.2 400-800 (#3 Connection Size) Diaphragm Gas Meter Installation
- Gas Design Standard J-12.3 1000 (#5 Connection Size) Diaphragm Gas Meter Installation
- Gas Design Standard B-13.1 Extra-Heavy Pipe Nipples
- Gas Design Standard J-56 Spool Pieces for Meter Sets
- Gas Design Standard H-103 Pietro Fiorentini Aperflux 851 Regulator
- Gas Design Standard B-40.8 Orifice Flanges

- Gas Design Standard G-11 Instrument Gas Filters
- Gas Design Standard B-40 General Flange Requirements
- Gas Design Standard J-101 Gas SCADA RTU Monitoring Design Requirements
- Gas Plan GP -1103 Customer-Connected Equipment Asset Management Plan
- TD-4878P-07 Well Bring-In with Nitrogen Gas Checklist
- TD-4878P-05 Well Kill
- Gas Design Standard B-13.4 Branch Nipple
- Gas Design Standard J-66.1 Test Instruments for Construction
- Gas Design Standard H-80 Mooney Flowgrid Regulator
- Engineering Material Specification EMS-4266 Valve Control Systems
- Engineering Material Specification EMS-4125 Trunnion-Mounted Carbon Steel Ball Valves
- Engineering Material Specification EMS-4267 Pneumatic or Electric Valve Actuators
- Technical Document TD-4580P-16 Pipeline Sampling Gas

a) Best Practice(s) Addressed by this Chapter

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

b) Effectiveness

This measure utilizes PG&E's existing process of updating its standards and procedures thus its effectiveness cannot be measured in reductions.

Part 2. Proposed New or Continuing Measure

PG&E will continue to utilize its existing programmatic system for pipe specifications as it includes a continuous improvement component that incorporates new tools, technology, and procedures to address changing code and compliance. The Standards Engineering team will continue to explore opportunities to use prefabricated components that will reduce the number of threaded connections.

Part 3. Abatement Estimates

This measure focuses on review and updating standards and procedures as well as continuous improvement in reducing threaded connections; therefore, emission reductions for this measure cannot be calculated.

Part 4. Cost Estimates and Average Annual Revenue Requirement

As stated above, this measure utilizes existing processes to review and update guidance documents and is performed by PG&E's Standard Engineering team. Funding for Standards Engineering work has been accounted for in PG&E's 2023 GRC under Operational Management and Operational Support.[21] No incremental funding is requested.

Part 5. Cost Effectiveness/Benefits

This measure utilizes PG&E's existing process of updating its standards and procedures; therefore, emissions reduction cannot be calculated based on this measure.

[21] PG&E's 2023 GRC Exhibit (PG&E-3), Chapter 13, p. 13-33, line 1.

CHAPTER 13: HIGH-BLEED PNEUMATIC DEVICE REPLACEMENTS

Part 1. Evaluate the Current Practices Addressed in this Chapter

Historically, PG&E reduced methane emissions at the Compression & Processing (C&P) and Regulator stations as part of planned station projects. Examples include the installation of electric/hydraulic actuators that have no emissions at gas terminals, and installation of Becker controllers that are classified as no bleed devices within M&C, as well as C&P facilities. Where feasible, compressed air is used as a control gas to eliminate the need of natural gas (e.g., the Milpitas Terminal uses air for regulating valve controllers).

PG&E has existing programs in place for systematically replacing the aging and obsolete equipment at both the gas transmission C&P and Regulator stations. Replacing the aging controllers to address obsolescence also has an added benefit of reducing the overall stations emissions.

For Transmission Compressor Station Facilities:

As required by the CARB Oil and Gas Rule, as of January 1, 2019, PG&E addressed all remaining high bleed devices at the C&P station and underground storage facilities by either replacing it with intermittent or low bleed controllers, removing the device, or converting it to air. In the 2022 Compliance Plan period, PG&E converted 18 intermittent valves from natural gas to instrument air in Hinkley and 7 intermittent valve actuators from natural gas to instrument air in Kettleman.

For Transmission Measurement & Control (M&C)[22] Station Facilities:

PG&E continues to identify, remove and replace the high bleed devices (Bristol controllers, Moore 74G and Fisher Positioners) with low bleed devices at its M&C facilities. Controllers installed on an obsolete actuator and plug valve were replaced with a new ball valve and actuator. Most of the high bleed devices were removed and replaced during the complex station rebuilds, routine capital work such as valve replacements or when stations are decommissioned. In the 2022 Compliance Plan period, PG&E replaced 12 high bleed controller replacements at three M&C stations.

a) Best Practice(s) Addressed by this Chapter

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

[22] Measurement & Control (M&C) and Measurement & Regulation (M&R) are interchangeable in this context.

b) Effectiveness

The 2015 emissions from transmission M&R stations and components at storage facilities are 579 MMscf and 10.6 MMscf, respectively. Emission factors from Appendix 9 of the Natural Gas Leakage Report for Leak Abatement OIR were used to characterize high-bleed controllers (18.6 scfh), intermittent bleed controllers (2.4 scfh) and low-bleed controllers (1.4 scfh). During the 2022 Compliance Plan period, PG&E accomplished the following:

- Converted 18 intermittent valves to instrument air in Hinkley, assuming 20 years, the emissions savings is 7.5 MMscf.
- Converted 7 intermittent valves to instrument air in Kettleman, assuming 20 years, the emissions savings is 2.9 MMscf
- Replaced 12 high bleed controller at three M&C stations, assuming 20 years, the emission savings is 39 MMscf.

Part 2. Proposed New or Continuing Measure

During the 2024 Compliance Plan period:

- Replace 6 high bleed devices, replace 5 intermittent devices with electric actuators, remove 6 high bleed devices, and replace 3 high bleed devices with electric actuators at 4 M&C stations, assuming 20 years, the emissions savings are 50.9 MMscf
- Convert 3 intermittent actuators to air-powered in Santa Rosa, assuming 20 years, the emissions savings is 1.3 MMscf.
- Convert 6 intermittent device replacements in Kettleman, assuming 20 years the emissions savings is 2.5 MMscf

The replacement of high bleed devices at C&P stations and underground storage facilities were addressed as part of the CARB Oil and Gas Rule. There are no incremental requirements associated with this Best Practice.

Part 3. Abatement Estimates

Planned actuator replacements during the 2024 Compliance Plan will result in a 54.7 MMscf reduction of emissions, over a 20-year time span. See part 2 for abatement estimate breakdown by compressor station.

Part 4. Cost Estimates and Average Annual Revenue Requirement

Replacement or removal of high bleed controllers will be performed as part of station rebuilds, which had funding adopted in the 2023 GRC Final Decision. No additional funding is requested for this measure.

Part 5. Cost Effectiveness/Benefits

For cost effectiveness, replacements or removal of the remaining high bleed pneumatic device at Regulator stations will be part of the planned station rebuild.

CHAPTER 14: DAMAGE PREVENTION

Part 1. Evaluate the Current Practices Addressed in this Chapter

Public Education

PG&E has a comprehensive public awareness program in the area of "call before you dig." Part of the program is the "811 Ambassador Program," which offers financial rewards to employees who identify contractors digging without an Underground Service Alert (USA) ticket. The 811 Ambassador calls have been summarized in Table 10 below:

Table 10 – Number of 811 Ambassador Calls by Year (2018 – 2022)

Year	2018	2019	2020	2021	2022
Number of Calls	3,001	5,858	1,824	955	755

PG&E's Dig-in Reduction Team (DiRT) provides in-person safe excavation trainings, free of charge to the public. Summarized in Table 11 below is the number of classes PG&E has held over the years:

Table 11 – Number of DiRT Training Classes Provided by Year (2018 – 2022)

Year	2018	2019	2020	2021	2022
Number of Classes	226	148	132	137	184

PG&E maintains a "safe digging" website to provide instruction to excavators on safe digging practices. This information is delivered to excavators in email messaging and social media outreach.

In 2023, as a result of these ongoing programs, PG&E experienced 1.01 total gas dig-in rate per 1,000 USA tickets.

Stand-by Monitors

PG&E currently requires stand-by monitors to be present when excavation work is done within 10 feet of gas transmission lines.[23] This is communicated to excavators through the USA ticket process; the locator, upon identifying the transmission facility, arranges a field meet with the excavator to discuss the schedule and stand-by process. PG&E provides this service (locating, field meet, and stand-by during excavation) free of charge.

Dig-In Reduction Team

PG&E's DiRT investigates and educates excavators who damage PG&E's underground facilities. The DiRT has a process to identify and interact with contractors who are responsible for multiple dig-ins during a 12 to 24-month period. The DiRT provides safe digging classes

[23] California Government Code 4216 requires PG&E to arrange a field meet when a USA Ticket is requested for work within 10 feet of a gas transmission pipeline. PG&E's current practice provides, in addition to the field meet, a standby exceeds the regulation and adheres to best practice.

free of charge, meets with third-party company leadership to establish ongoing relationships, and documents the damages for billing purposes. The DiRT works on a regional level with municipalities to educate excavators on safe digging practices and work through escalation process when there are recurring issues with excavators, which can result in referrals to the Contractor State License Board.

a) Best Practice(s) Addressed by this Chapter

Best Practice 24 - Dig-Ins / Public Education Program: Dig-Ins – Expand existing public education program to alert the public and third-party excavation contractors to the Call Before You Dig – 811 program. In addition, utilities must provide procedures for excavation contractors to follow when excavating to prevent damaging or rupturing a gas line.

Best Practice 25 - Dig-Ins / Company Standby Monitors: Dig-Ins – Utilities must provide company monitors to witness all excavations near gas transmission lines to ensure that contractors are following utility procedures to properly excavate and backfill around transmission lines.

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

b) Effectiveness

In the 2022 Leak Abatement OIR Report, PG&E reported 2.1 MMscf in transmission all damages, which is a 97% decrease, compared to the 2015 baseline. Comparing 2021 to 2022, there was a decrease of 0.4 MMscf in emissions.

In the 2022 Leak Abatement OIR Report, PG&E reported 53.6 MMscf in distribution all damages, which is a 62% decrease, compared to the 2015 baseline. Comparing 2021 to 2022, there was an increase of 16 MMscf in emissions due to an increase in the number of damages.

Part 2. Proposed New or Continuing Measure

PG&E will continue implementing its damage prevention program to comply with these best practices. No new actions are proposed for the 2024 Compliance Plan period.

The compliance requirements/regulatory commitments that require a public awareness program include the following: California Government Code Section 4216; Code of Federal Regulations (CFR) Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Section (§) 192.703 (b) and (c), "General."; 49 CFR Part

196, “Protection of underground pipelines from excavation activity.”; and Senate Bill 661, Chapter 809, September 29, 2016, SEC 23.955.5. PG&E’s 811 Ambassador Program, the education programs delivered by the DiRT team, and Gold Shovel Program meet and exceed the public awareness regulations that govern PG&E gas transmission and distribution systems. No part of this measure is incremental to the regulations noted herein.

Part 3. Abatement Estimates

Emissions from pipeline damages can vary from year to year, depending upon the number of construction projects that occur in that particular year. Comparing the 2015 baseline for Transmission Pipeline – All Damages & Distribution Main & Services – All Damages to the 2022 emissions, the emissions reduction is 167 MMscf. This emissions reduction is projected to remain the same for 2024-2025 as there is no incremental work planned.

Part 4. Cost Estimates and Average Annual Revenue Requirement

PG&E’s Damage Prevention public awareness, DiRT and standby costs and annual revenue requirements were adopted in PG&E’s 2023 GRC as follows:

2024
Public Awareness: $3.47 million [24]
Dig-In Reduction Team: $3.67 million [25]
Standby: $6.04 million [26]

2025
Public Awareness: $3.54 million [23]
Dig-In Reduction Team: $3.78 million [24]
Standby: $6.23 million[25]

No incremental work is planned to comply with this Best Practice; therefore, no additional funding is requested.

Part 5. Cost Effectiveness/Benefits

This measure is the implementation of programs to reduce dig-ins. Emissions from transmission and distribution dig-ins and year-over-year emissions reductions are reported in PG&E’s Natural Gas Leakage Report for the Leak Abatement OIR. The net annual cost is $12.9 million, which includes the sum of the activities in part 4 less the cost of gas saved. The standard cost effectiveness of this measure is $77/Mscf. The cost effectiveness when considering avoided Cap-and-Trade is $75/Mscf. The cost effectiveness when considering avoided Cap-and-Trade and social cost of methane is $50/Mscf. No incremental work is planned to comply with this Best Practice.

[24] PG&E’s 2023 GRC Exhibit (PG&E-3), Chapter 5, WP Table 5-29. Note: The adopted dollars for this program include a reduction to PG&E’s original request.
[25] PG&E’s 2023 GRC Exhibit (PG&E-3), Chapter 8, WP Table 8-6.
[26] PG&E’s 2023 GRC Exhibit (PG&E-3), Chapter 8, WP Table 8-5.

CHAPTER 15: R&D PROJECTS

Part 1. Evaluate the Current Practices Addressed in this Chapter

Part 1 is not applicable because the R&D projects proposed under this Measure are forward looking; therefore, this Best Practice cannot be compared.

Part 2. Proposed New or Continuing Measure

In the 2022 Compliance Plan Period, PG&E created the Grid Research, Innovation and Development (GRiD) team. The team identified where R&D is most needed across our system and distilled these needs into several problem statements, which are shared in PG&E's R&D Strategy Report. These problem statements span the gas and electric side of the business. Three themes were identified in the Gas section:

> Theme 1: Maintain and continually improve system safety and reliability, while reducing O&M costs
>
> Theme 2: Reduce methane emissions from the gas system Theme 3: Decarbonize the gas
>
> system

The Natural Gas Leak Abatement Program fits within theme 2, where PG&E has set ambitious goals for decreasing emissions over the next 25 years as part of its broader climate strategy.

Continuing to meet company targets for methane emissions reductions will require investment in equipment upgrades and highly effective leak detection and repair technologies. In this research category, Gas R&D funds projects that develop or advance technologies that, if deployed widely, would reduce scope 1 methane emissions from PG&E's gas system. Gas R&D's efforts in this area are broadly focused on four areas:

- **Revised Emissions Calculation Methodologies**: The figures for the Transmission Meter & Regulation station leaks and emissions are not based on actual recorded emissions but instead on population-based emission factors. While efficient, this approach does not provide accurate emissions information. To address this challenge, Gas R&D staff support projects that are developing more granular emission calculation methods and the ability to continuously and cost-effectively detect and quantify on-site emissions levels at the component level. Continuous monitoring has the potential to improve emissions reporting from stations and storage facilities and maximize emissions reduction efforts by prioritizing the highest emitters for replacement.

- **Meter Set Leak Repair:** The current meter set leak repair process is time-consuming and increases ergonomic exposure for workers completing the repairs. Technologies to shorten meter set repair times and ensure a high-quality seal without breaking down the meter set can help reduce emissions and ensure worker safety while completing repairs. Projects in this area seek to develop novel technologies that minimize repair times, reduce the need for follow-up service visits, adhere to seal quality & pressure requirements, and support subsequent replacements and repairs. Because visual atmospheric corrosion inspections of meter sets are costly and subjective, projects in this area also seek to develop technologies that can remotely monitor meter sets for corrosion and successfully detect corrosion, alert repair crews, and/or shut off the meter set if failure is imminent.

- **Aerial Leak Detection & Quantification**: PG&E has a large service territory with certain segments of transmission pipe in difficult to reach locations. Projects in this area seek to develop various technologies for cost-effective, aerial leak detection and quantification. One project is focused on verifying the emissions quantification performance of a helicopter mounted LIDAR used to detect transmission leaks. PG&E is also assessing the performance of drone mounted methane LIDAR sensor with the eventual goal of performing leak surveys on suspended or submerged pipes and leak detection during emergencies. PG&E is also collaborating with a vendor to verify GPS coordinates & methane leak detection using video and images captured from satellites in near Earth orbit.

- **Reducing Pipeline Blowdown Methane Emissions:** Blowdowns are often necessary to depressurize a pipeline for testing or other purposes. Current methane abatement strategies used when venting pipelines include cross-compression, flaring, and thermal oxidation. These methods are effective at reducing emissions released into the atmosphere during the venting process, but are costly, time consuming, and require heavy equipment. Projects in this area seek to reduce cost and size of required equipment relative to current state of the art cross-compression technologies and prevent emissions from entering the atmosphere.

a) Best Practices(s) Addressed by this Chapter

Best Practice 20a - Quantification & Geographic Tracking: Utilities shall develop methodologies for improved quantification and geographic evaluation and tracking of leaks from the gas systems. Utilities shall file in their Compliance Plan on how they propose to address quantification. Utilities shall work together with the CPUC and ARB staff, to come to agreement on a similar methodology to improve emissions quantification of leaks for the purpose of tracking emissions reductions.

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

<u>Part 3. Abatement Estimates</u>

This measure focuses on R&D projects and strategies that are forward looking; therefore, emission reductions for this measure cannot be calculated.

Part 4. Cost Estimates and Average Annual Revenue Requirement

PG&E's Gas R&D program has adopted expenditures of approximately $7.9 million in 2024, and approximately $8.1 million in 2025.[27] Please note that these costs are for the entire Gas R&D and Deployment Program, and not just 2024 Compliance Plan activities. No incremental funding is being requested in this Compliance Plan.

Part 5. Cost Effectiveness/Benefits

Part 5 is not applicable because the R&D projects proposed under this measure are forward looking.

[27] PG&E's 2023 GRC Exhibit (PG&E-3) Chapter 13, WP Table 13-10. Note: The adopted dollars for this program include a reduction to PG&E's original request. The Commission's decision also established a one-way balancing account for the Gas Research and Development program for the 2023-2026 rate case period.

SECTION D. CONCLUSION

PG&E's 2024 Compliance Plan will continue its progress toward meeting the 40 percent emissions reduction goal by 2030. However, there are current limitations on reaching the reduction goal due to emissions from various assets being estimated using the population-based method. Under this framework, PG&E can only show a reduction in emissions by reducing the population of an asset. To meet these reduction goals, the baseline and the methodology needs to be updated and approved such that progress with actual emission reduction efforts can be measured. PG&E's R&D and GRiD team will continue to conduct research and development studies, in collaboration with CPUC and CARB, to develop new methods and technologies to enable methane emission reduction, refine emission factors for more accurate emissions reporting, and propose additional emission reduction activities that are both meaningful and cost-effective. To meet the goal by 2030, PG&E will continue to the reduce the Super Emitter threshold, to extend blowdown reduction strategies to Compressor Station and Storage facilities, and develop measurement-based emission reporting methodology.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 3

CHANGE LOGS FOR PG&E'S ASSET MANAGEMENT PLANS, GAS EMERGENCY RESPONSE PLAN, AND COMPANY EMERGENCY RESPONSE PLAN

A. Change Log

Table 5 summarizes revisions since the previous publication of GP-1100: Strategic Asset Management Plan," Revision 10, 04/21/2023.

Table 5 – SAMP Change Log

Revision 10 Changes			
Section	**Change**	**Reason for Change**	**Implication of Change**
Entire document	General annual updates. Updated language and figures to reflect updates made in 2022. Updated use of acronyms where appropriate. Updated titles to reflect organizational changes. Updated language to reflect PG&E's True North Strategy.	These are general updates that require annual refresh or updates that help refine the document's messaging.	Updated Information
Entire document	Removed references to PAS 55	PAS 55 has been retired and has been replaced by ISO 55001	None.
Introduction	Updated PG&E's "Purpose, Virtues, and Stands" to include the True North Strategy. Removed bulleted list – TNS graphic now included in Section 2.3	Updated to align with Senior Leadership's vision of the company.	Updated information in the SAMP may also require alignment in the individual AMPs.
Section 1.1	Removed bulleted list – TNS graphic now included in Section 2.3	Better readability	Updated information
	• Added graphic depicting Asset Management lifecycle. Renumbered figures to follow.		
Table1	Updated data where appropriate in "description" columns.	Updated information	Updated information
Section 2.3	Added True North Strategy placemat with explanatory material. Also added highlights of the Lean Operating System.	Updated information	Updated information

Section 2.4.1	Replaced “integrated planning” with “business plan deployment (BPD)” process.	Updated information	Updated information
Section 2.5	Updated section to reflect new Business Plan Deployment process and removed detail on IPP.	Updated information	Updated information
Section 2.6	Updated with latest language from 2023 Gas Safety Plan revision	Updated information	None. Alignment with other plans.
Table 3 and Table 4	Updated RACI matrix and roles and responsibilities.	Updated information	Updated information
Appendix D	Updated Gas Work Process Architecture.	Updated information	Updated information
Appendix G	Updated Table 11 - Communication Plan	Updated information	Updated information

F. Change Log

Table 19 summarizes revisions for Revision 10, since the previous publication of GP-1101, "Transmission Pipe Asset Management Plan," Revision 9, that was published April 2023.

Table 19. Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Updated statistics, tables, and figures	Annual update	Updated content
Section 1	No change	—	—
Section 2	Updated statistics, tables, and figures	Annual update Removed SCADA	Updated content. SCADA assets transferred to M&C asset family in March 2023.
Section 3	Updated	Update for enterprise risk guidance and consistency with other asset management plans	Updated with current business risk practices. Removed reference to risk evaluation tool for transmission pipe.
Section 4	Updated	Strategic objectives, annual update	Revised and updated content around revised strategic objectives and programs.
Section 4.2	Updated	Annual update	Removed reference to SCADA visibility and added GT system capacity.
Section 5	Updated	Annual update	Documents recent results and forward-looking continuous improvements.
Appendix A	No change		
Appendix B	Updated	Annual update	Revised and updated content around threat knowledge.
Appendix C	No change		
Appendix D	No change		
Appendix E	No change		
Appendix F	Updated	General update	None
Appendix G	No change		
Appendix H	Updated	Annual update	Updated status of R&D projects.
Appendix I	No change		
Appendix J through N	Added	Future placeholders	In accordance with SAMP, added placeholders for future common appendices.
Appendix O	Updated	Annual update	None

F. Change Log

Table 13 summarizes changes made to this revision.

Table 13. AMP Change Log

Section	Change	Reason for Change	Implication of Change
Entire AMP	• Updated statistics, tables, figures, and asset inventory information	Annual data update	Updated content
Section 1	• Removed timing component from Gas financial and strategic outlook	Alignment with True North Strategy which is a 10-year strategy	Updated content. Corporate evolution from before integrated planning process.
Section 2	• Updated statistics, tables, and figures. • Added content on residential methane detectors and AMI SmartMeter modules.	Annual data update	Updated content
Section 3	• Updated entire section	Update for enterprise risk guidance and consistency with other AMPs	Updated with current business risk practices.
Section 4	• Updated strategic objectives	Annual update and alignment of strategic objectives with PG&E's True North Strategy	Revised and updated content around revised strategic objectives and programs.
Section 5	• Updated progress and challenges for each strategic objective • Annual updates	Annual update	Documents results as of annual management review meeting.
Appendix B	• Updated statistics, tables, and figures	Annual update	Updated statistics and tables.
Appendix C	• Updated tables	Removed legacy columns from tables.	Removed columns that referenced legacy risk evaluation tool ID numbers
Appendix D	• Updated table	Updated table to reflect current department names and primary contact person titles	Updated content
Appendix F	• Updated content	General update of document changes	None
Appendix G	• Updated strategic objectives and performed annual update of lifecycle cost analysis	Annual update	Revised and updated content
Appendix H	• Updated content	Annual update	Updated status of R&D projects.
Appendix I	• Updated content	Annual update	Revised and updated climate vulnerability assessment key takeaways into a single table

F. Change Log

The following table summarizes revisions since the previous publication of Gas Plan GP-1104: Measurement and Control Asset Management Plan, Revision 8, August 2021.

Table 16. Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Updated to previous version of Asset Management Plan dated August 7, 2021	Updated information regarding fleet of M&C assets; areas of progress and continuous improvement associated with M&C assets	Updated information
Section 2.2	Updated asset inventory count, updated Transmission Station Age Distributions figures, updated Station Age Statistics table, updated Asset Health Commentary table	Annual update	Updated information
Section 3	Updated content on Enterprise risk management process; added bowtie for Loss of Containment Enterprise Risk Model	New information available	Updated information
Section 4	Updated strategic objectives along with target(s)/metric(s)	Annual update	Updated information
Section 5.1	Updated progress and challenges associated with strategic objectives.	Annual update	Updated information
Section 5.4	Modified introduction to R&D	More accurately reflects objectives of efforts	Updated information
Appendix A	Updated appendix "Related Documents"	Updated list	New information
Appendix B	Updated Threat Matrix	Annual update	Updated information
Appendix C	Updated to include only risks not covered by Enterprise Risk Models	Change in intent of appendix	Updated information
Appendix D	Updated based on reorganization	Update to accurately reflect roles and responsibilities	Updated information
Appendix H	Updated appendix "Research & Development"	Updated R&D projects that apply to the M&C asset family	Updated information
Appendix I	Updated Obsolescence Management Section	Need to accurately reflect current obsolescence issues	Updated information
Appendix J	Updated Region 1 information and added Region 2 information.	New information available	New information
Appendix M	Updated to latest version of plan	Annual update	Updated report

F. Change Log

Table 17 summarizes revisions since the previous publication of GP-1105, “Compression and Processing Asset Management Plan,” Revision 9, 08/17/2022.

Table 17 – Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Section 1	Added Figure 1	Consistent with other AMPs	New information
Section 2	Updated Table 3 and Table 4	Updates available	Updated information
Section 2.2.1	Updated improvements and challenges for all facilities in Table 5	Progress in station projects; changes in station condition	Updated information
Section 2.2.2	Updated unscheduled outage information; added information on McDonald Island units	Inclusion of 2023 outage information; progress on McDonald Island units	Updated information
Section 2.2.3	Added information on data used to monitor asset condition/performance	Prior revisions did not include	New information
Section 2.3	Updated information on Tionesta Compressor Station	Changing conditions influencing decision-making	Updated information
Section 3	Revised section structure and updated content on Enterprise risk management process	Changes based on updates to risk modeling methodology and scores	Updated information
Section 4	Updated strategic objectives along with target(s)/metric(s)	Annual update	Updated information
Sections 4.1 and 4.2	Updated programs	Consistency with 2023 GRC	Updated information
Section 5.1	Updated progress and challenges associated with strategic objectives	Annual update	Updated information
Section 5.4	Modified introduction to R&D	Consistent with other AMPs	Updated information
Appendix A	Updated appendix “Related Documents"	Updated list	Updated information
Appendix B	Updated threat matrix	Approval in October 2023	Updated information
Appendix D	Updated based on reorganization	Update to accurately reflect roles and responsibilities	Updated information
Appendix H	Updated appendix “Research & Development”	Updated R&D projects that apply to the C&P asset family	Updated information
Appendix I	Removed appendix	Pending leadership approval	Removed information

Gas Guidance Document Analysis (GDA)
LNG/CNG Asset Management Plan
GP-1106, Rev. 9

Document Type	Gas Plan
Workflow	Annual Mid-Year Revision

1. What is Changing and Why?

This gas plan (GP-1106, "LNG/CNG Asset Management Plan") is being updated per the annual review process by Pacific Gas and Electric Company (PG&E or Company) asset management principals and associated leadership and subject matter expert stakeholders.

- Applied an annual update to the content, statistics, tables, and figures throughout the plan.
- Updated Sections 1 through 5 and all appendices to ensure document consistency with other gas plan documents, and updated content.
- Updated strategic objectives and risk controls and programs.

2. Major New Risks or Changes to Existing Mitigated Risks (such as Process Safety risks)

NA

3. Stakeholders

Table 1. Technical Stakeholder Reviewers (required to be considered)

Department / Work Center	Title (and Role if applicable)	Name (LAN ID) (or reason if NA)	Date Reviewed
LNG/CNG Operations and Engineering	Senior Manager, Document Steward	[redacted]	08/2023
Standards Engineering	Expert Gas Engineer, Document Coordinator	[redacted]	08/2023
Standards Engineering	Principal Engineer, Lead Engineer	[redacted]	08/2023
LNG/CNG Operations and Engineering	Senior Manager, Document Approver	[redacted]	08/2023
Process Safety Process-safety@pge.com	NA – No changes to step-by-step field instructions		
Quality Management	NA – No associated quality assessments		
Operator Qualification	NA – No associated qualifications		
Technology Solutions	NA – No technology or electronic form changes required (Pronto, SAP)		
Regulatory Compliance GasOpsSPRegulatoryCompliance@pge.com	NA – No governing federal or state pipeline regulations. No significant changes to TIMP program requiring Reg. Compliance review for notification purposes.		
PG&E Academy	NA – No associated Academy training		
As-Built Records	NA – Does not affect as-built documents		

Table 1. Technical Stakeholder Reviewers (required to be considered) (continued)

Department / Work Center	Title (and Role if applicable)	Name (LAN ID) (or reason if NA)	Date Reviewed
Integrity Management (DIMP, FIMP, TIMP)	NA – Does not introduce a new part or change an existing part's specifications; change the installation, operation, maintenance, or removal process of any portion of an asset; change test requirements for any assets; or change data gathering or forms		

Table 2. Target Audience Usability Review (stakeholders that may review)

Department / Work Center	Title	Name (LAN ID)	Date Provided	Gave Input?
LNG/CNG Engineering.	Manager	[redacted]	10/2023	yes
Gas Safety Excellence	Manager, Program Management	[redacted]	10/2023	yes
Gas Safety Excellence	Business Project Manager, Principal	[redacted]	10/2023	yes
LNG/CNG Engineering	Principal Asset Family	[redacted]	07/2023	yes

4. Electronic Document Routing System (EDRS) Reviewers and Approvers

Approvers: [redacted]

EDRS Routing Number: 2023-47752

5. Cost Information

NA

6. Schedule Information

Effective Date: 11/27/2023

GP-1106 will be implemented per Appendix G, "Asset Life Cycle," in GP-1100, "Strategic Asset Management Plan."

7. Review Frequency

☒ No Change to Review Frequency

At least once every calendar year, not to exceed 15 months, to the date

8. Cancellations

NA

Gas Guidance Document Analysis (GDA)
LNG/CNG Asset Management Plan
GP-1106, Rev. 9

9. Manuals

☒ No Change to Manuals

10. Document Properties

Functional Area

☒ CNG-LNG	☐ Compression and Processing	☐ Customer Connected Equipment	☐ Distribution Mains
☐ Distribution Services	☐ Measurement and Control	☐ Storage	☐ Transmission Pipe

Target Audiences

☐ Asset Strategy	☐ Facility Integrity Management	☐ Leak Repair	☐ R&D and Innovation
☐ Associate Distribution Engineers	☐ GPOM (I&R)	☐ Leak Survey	☐ Records and Information Management
☐ Compliance and Risk	☐ Gas Control Strategy and Support	☐ Locate and Mark	☐ Regulatory Compliance
☐ Contract Management	☐ Gas Distribution Control Center	☐ Mapping (Transmission and Distribution)	☐ Risk Management
☐ Corrosion Mechanics	☐ Gas Emergency Preparedness	☐ Metering Plant	☐ Service Planning
☐ Corrosion Services	☐ Gas Operations Leadership	☐ Picarro	☐ Sourcing
☐ Data Quality	☐ Gas Service Representatives	☐ Pipeline Engineering	☐ Super Gas Ops
☐ Dispatch and Scheduling	☐ Gas Transmission Control Center	☐ Pipeline Safety Enhancement Plan Engineering	☐ System Planning
☐ Distribution Construction	☐ General Construction	☐ Program Management (Transmission and Distribution)	☐ Technology and Tools
☐ Distribution Engineering	☐ Hydrotesting	☐ Project Management (Transmission and Distribution)	☐ Transmission Construction
☐ Distribution Integrity Management	☐ Investment Planning	☐ Qualifications	☐ Transmission Engineering
☐ Estimating	☒ LNG|CNG Operations	☐ Quality and Improvement	☐ Transmission Integrity Management

Business Processes (GODOCS)

CONSTRUCTION	ENGINEERING	MAINTENANCE & OPERATIONS	EMERGENCY / ADMIN
☐ As-Builts	☐ Applicant Design Manual	☐ Corrosion Control	☐ Dispatch and Scheduling
☐ Coatings	☐ Asset Knowledge Management	☐ Damage Prevention (indicate subtype)[1]	☐ Emergency Plans
☐ Construction Methods	☐ Distribution Engineering	☐ Field Services (GSRs)	☐ Gas Guidance Document Process
☐ Environmental and Safety	☒ Engineering for Integrity Management	☐ Gas Control and Clearances	☐ Gas Operations Quality Management
☐ Excavation	☐ Engineering Material Specifications	☒ Integrity Management (IM)	☒ Gas Safety Excellence
☐ Gas Design Standards for Construction	☐ Gas Design Standards	☐ Leak Survey and Response	☐ Operator Qualifications (OQ)
☐ Inspection and Operation	☒ Process Safety	☐ Major Stations	
☐ Plastic	☐ System Planning	☐ Measurement and Regulation (M&R)	
☐ Steel Pressure Control	☐ Transmission Engineering	☐ Steel Pipeline Maintenance and Repair	
☐ Strength Testing and Commissioning		☐ Valve Maintenance	
☐ Welding and Nondestructive Examination (NDE)			

1. Damage Prevention subtypes: Locate and Mark, Patrolling, Public Awareness

F. Change Log

Table 24 summarizes revisions since the previous publication of Gas Plan GP-1108, "Gas Storage Asset Management Plan," Revision 9, September 2022.

Table 24. Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
All	Updated all figures and tables with 2022/2023 operational data and information	Annual Document Refresh	NA – General Updates
1 Introduction	Reorganized and reordered content for better presentation of information	Document Improvements and Annual Refresh	NA – General Updates
2 Asset Inventory, Condition, and Life Cycle	• Added additional subsections to define and explain the role of storage. • Added Subsection 2.1.1 summarizing the 2022-2023 winter gas pricing increase • Added additional visuals to better communicate PG&E and California asset data • Added asset counts in Subsection 2.4 • Added Subsection 2.7, "Request for Approval of PG&E's Reinspection Methodology and Plan" • Added Subsection 2.10, "Flow Rate Changes," Figure 10, and Table 8 • Added Figure 12 • Updated Figure 13 and added Table 11	Document and Data Improvements	NA – General Updates
3 Risks and Threats	• Rewrote Section 3 to provide better context into EORM risk modeling • Added Subsection 3.5 "Incurred Risk of Frequent inspections" • General updates to tables and visuals	Document Improvements and Annual Refresh	NA – General Updates
4 Desired State, Strategic Objectives, Programs and Risk Mitigations	• Updated Table 15 to align with 2023 TNS	Document Improvements and Annual Refresh	NA – General Updates
5 Areas for continuous Improvement	• Updated Subsection 5.1	Document Improvements and Annual Refresh	NA – General Updates
Appendices	Updated figures and tables with 2022 operational data and information	Document Improvements and Annual Refresh	NA – General Updates

F. Change Log

The following table summarizes revisions of this AMP when changes occur.

Table 9. Asset Management Plan Change Log August 2023

Section	Change	Reason for Change	Implication of Change
Entire document	Updated all tables and figures to reflect the most current data available.	Program maturity	Updated content
Entire document	Updated to ensure document consistency and updated asset information.	Program maturity	Updated content
Table 5	New		
Appendix K	New	Providing information on the number of datasets identified with Gas risks and drivers.	None

Document Control

This section contains Pacific Gas and Electric (PG&E) information related to the ownership and maintenance of this document. This document undergoes an annual review and update as needed and in compliance with EMER-2001S, Company Emergency Operations Plans Standard published in Guidance Document Library (GDL). Emergency Preparedness and Response (EP&R) maintains this Company Emergency Response Plan (CERP).

Change Record

The Change Record table given below is used to record all changes made to the plan. It describes the revisions made, the locations of the revisions, the names of the persons responsible for the revisions, and dates of revisions:

Section	Person Responsible for Revision	Change	Date
1.5	[redacted]	Changed header title from "Emergency Planning & Hazards" to "Emergency Planning Assumptions & Hazards."	7/14/23
1.5.2	[redacted]	Added Corporate Risk Registry enterprise risk list link.	7/18/23
1.5.3	[redacted]	Updated per EMER-2001S to include reference to CRR correlation and THIRA based CERP hazard annex planning.	10/20/23
2.4.2	[redacted]	Updated link to Electric Operations SharePoint site.	10/3/23
2.4.4	[redacted]	Updated Power Generation Emergency Preparedness team content.	10/3/23
2.4.5	[redacted]	Updated DCPP nuclear facility items.	10/3/23
2.5.1.1	[redacted]	Changed "Gas Response Operations" team title to match "Gas Emergency Preparedness" team title listed in CERP GERP Annex v12.	9/28/23
2.8	[redacted]	Updated Wildfire Risk Command Center content.	10/2/23
2.9.1.1	[redacted]	Adding Gas IMT reference per GERP subsection 2.2.1.2.1.	10/6/23
2.9.1.2	[redacted]	Added reference to Electric IMT details per CERP Electric Annex subsection 2.2.11 and EMER-4501S, Electric IMT Framework.	10/6/23
3.1.5	[redacted]	Updated per CERP Electric Annex v4, subsection 3.2.3.4.2, showing STOEC,	9/13/23

Section	Person Responsible for Revision	Change	Date
		EDEC and ETEC activation in relation to DCC and GCC facilities.	
3.2.1	[redacted]	Added "Bottom-Up Activation" subsection.	8/11/23
3.2.2	[redacted]	Added "Top-Down Activation" subsection with PSPS event example.	8/11/23
3.3	[redacted]	Added Command & General Staff SIPOC content copied from 2023-2025 WMP, subsection 8.4.2.	6/28/23
5.1	[redacted]	Updated to include ICS based incident/event management content.	8/17/23
5.5.2	[redacted]	Updated HAWC content.	7/17/23
5.6.2	[redacted]	Updated SOPP description to include 28-year historical analysis, category, and time of adverse weather impacts.	10/26/23
5.6.3	[redacted]	Updated earthquake and tsunami content.	10/26/23
5.6.4	[redacted]	Updated POMMS subsection content.	10/26/23
5.6.5	[redacted]	Removed reference to three-kilometer POMMS resolution.	10/26.23
5.6.6	[redacted]	Updated debris flow hazard modelling and warning content.	10/26/23
5.8.2	[redacted]	Changed MYTEP title to Integrated Preparedness Plan per U.S. Homeland Security Exercise and Evaluation Program doctrine.	11/15/23
5.8.3	[redacted]	Added core capability aligned exercise content per EMER-2501M, 2023-2025 MYTEP, subsection 1.1 and section 2.	7/6/23
7.1.3	[redacted]	Change last bullet to read: "Ensures proper analysis of safety incidents is performed."	10/3/23
7.1.6.1	[redacted]	Updated PSS Agency Representative content per EMER-4002S, to include AHJ and EOC activation support descriptions.	6/30/23
7.3	[redacted]	Noted potential use of multiple I&I sections for concurrent threats.	11/7/23

Section	Person Responsible for Revision	Change	Date
7.4.1	[redacted]	Added new EOC Coordinator position and responsibilities per 7/19/23 EP&R Response Team notification.	8/3/23
7.5	[redacted]	Added footnote reference to Logistics Section Reporting Unit role described in EMER-3005M, CERP Logistics Annex v3, subsection 4.1.2.2, Incident Intelligence Summary.	11/17/23
7.5.1.1 – 7.5.1.2	[redacted]	Separated land management and environmental unit functions.	11/8/23
8.1.1.	[redacted]	Added CERP Electric Annex, EMER-3002, subsection 2.1.2.1 reference.	10/3/23
8.1.5	[redacted]	Changed REC reference from three to five.	10/3/23
10.3.1	[redacted]	Created new "Demobilization Planning" subsection title, consolidated demobilization planning subsection content.	10/18/23
10.3.3	[redacted]	Changed header from "EOC Demobilization Unit" to "Demobilization Unit"; removed EOC specific reference.	10/18/23
Table 2-1	[redacted]	Updated to reflect PG&E organization per Who's Who organization chart as of September 28, 2023.	9/28/23
Table 2-1	[redacted]	Added contractor safety to list of EH&S responsibilities.	10/3/23
Table 2-1	[redacted]	Adding 'Engineering' to Gas Operations title.	10/27/23
Figure 3-3	[redacted]	Added I&I section to ICS task organization example.	11/8/23
Figure 7-1 & 7-2	[redacted]	Removed EOC Coordinator from Command Staff organization per EP&R Response Team notification.	8/3/28
Figure 7-8	[redacted]	Added EOC Coordinator to Planning Section organization chart per EP&R Response Team notification.	8/3/23
Figure 7-8	[redacted]	Added Mutual Assistance Unit to EOC Planning Section organization chart.	11/16/23

Section	Person Responsible for Revision	Change	Date
Figure 7-9	[redacted]	Updated EOC Logistics Section organization chart to align with EMER-3106M, PSPS Annex v8, figure 2-1 organization chart.	11/16/23
Figure 12	[redacted]	Reformatted PG&E "Operational Levels and Emergency Facilities" graphic, to include distinctions between Gas and Electric division totals and the addition of ETEC and EDEC to level 4 and 5 activations.	10/9/23
Appendix F.2	[redacted]	Updated activated emergency facility list to align with current EOC IAP format.	11/16/23

Recision Log

Document Number	Title
NA	NA

Reference Documents

Document Number	Title
EMER-01	Emergency Preparedness and Response Policy
EMER-2001S	Company Emergency Response Plans Standard
EMER-2001S-F01	Change Request Form
EMER-2003S	EOC Activation After-Action Report (AAR) Process Standard
EMER-2004S	EOC Documentation Standard
EMER-2501M	Multi-Year Training and Exercise Plan, 2023-2025
EMER-3001M-Att01	Cal OES Regional Contacts
EMER-3001M-Att02	County Government Contacts
EMER-3005S	PG&E's Emergency Field Site Request and Approval Standard
EMER-3105M	Wildfire Annex
EMER-3106M-01	Access and Functional Needs (AFN) Plan
EMER-4002S	Public Safety Specialist Standard
EMER-4501S	Electric Incident Management Team Standard
EMER-4510S	Operations Emergency Center (OEC) Activation Requirements,
RISK-5001S	Enterprise and Operational Risk Management Standard
RISK-5001P-01	Enterprise and Operational Risk Management Procedure

Document Control

Emergency Preparedness and Response (EP&R) Strategy & Execution, , maintains the Gas Emergency Response Plan Annex (GERP) to the Company Emergency Response Plan (CERP). This section records the revisions made to the GERP, 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 12.0).

Where?	What Changed?	Who Initiated the Change?
1.2.1	Removed 1.2.1 Gas Emergency Response Guide section.	[redacted]
Throughout	Changed "Gas Emergency Preparedness" to "Gas Emergency Response".	[redacted]
1.4.2	Updated that EP&R Training and Exercises is responsible for training. Also, changed Multi-Year Training and Exercise Program (MYTEP) to Integrated Preparedness Plan (IPP).	[redacted]
Throughout	Updated job titles, links, and document references.	Various
Throughout	Made edits and grammar updates.	Various
2.1.2	Updated the Gas emergency center address/location.	[redacted]
2.2.1.1	Updated Gas Emergency Response functions.	[redacted]
3.4.4	Updated the list of tools and technology systems being used.	[redacted]
Throughout	Added references to the Gas Engineering Earthquake Playbook.	[redacted]
4.2.3	Updated the list of critical communications systems, tools, and devices during emergency events.	[redacted]
5.2	Updated guidance document references.	[redacted]
Throughout	Changed Lines of Business to Functional Areas (FAs).	[redacted]
A.1	Updated the list.	Various
B.4	Updated the Incident Specific Matrix.	Various
E.5	Updated external agency contacts.	Various

Recision Log

Document Number	Title
NA	NA

Reference Documents

Document Number	Title
	[See Appendix A.2]

Document Preparer

Name	Position
[redacted]	Gas Program Manager, Expert
(Various SMEs)	Gas Emergency Response

Document Owner

Name	Position
Joe Forline	Senior Vice President, Gas Operations

Document Reviewers

Gas System Operations (GSO), Gas Emergency Response and Gas Technical Document Management.

Name	Position
[redacted]	Manager, Emergency Preparedness, EP&R Planning
[redacted]	Director, Gas Control

Document Approvers

Name	Position
[redacted]	Senior Director, Gas System Operations & Maintenance
Joe Forline	Senior Vice President, Gas Operations

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 4

CHANGE LOG FOR 2024 GAS SAFETY PLAN

Attachment 4
Change Log for 2024 Gas Safety Plan

This attachment lists notable changes in both the report narrative and the attachments between PG&E's 2023 Gas Safety Plan and 2024 Gas Safety Plan.

Section No.	Section Title	Change Description
I	Introduction	Updated number of transmission pipeline miles to 6,400. Updated number of distribution pipeline miles to 44,000 miles.
I.1	Structure of the Gas Safety Plan	Added True North Strategy as a highlight to this section. Updated reference from Gas Safety Excellence Management System (GSEMS) to PG&E Safety Excellence Management System (PSEMS) as PG&E initiated its transition to PSEMS in 2023.
I.2	PG&E Goals	Updated Figure 2, PG&E's True North Strategy, which includes PG&E's updated stand on the planet.
I.3	PG&E Safety Excellence Management System	The 2024 Gas Safety Plan includes 2023 safety excellence management system assessment results in Figure 3.
I.4	Public Safety	Added reference to PG&E's Strength Test program, highlighting the completion of the final NTSB Recommendation following the San Bruno incident.
I.5	Workforce Safety	Added Figure 5, PG&E's 10 Keys to Life.
I.7	Natural Gas Leak Abatement Compliance Plan	The 2024 Gas Safety Plan includes the biennial Natural Gas Leak Abatement Complaince Plan required by D.17-06-015.
II.1	Coworker Engagement	Added reference to first 12 completed Breakthrough Workshops.
II.1	Coworker Engagement	Added section for PG&E's Coworker Town Halls with focus on equiping and empowering leaders to be owners of their work.
II.1.c	Material Problem Reporting	Expresses PG&E's 2023 improved average cycle time to resolve Material Problem Reports of 7 days, exceeding the 2023 target of 20 days.
II.2	PG&E Corporate and Gas Safety Committees	Updated Table 2 to reflect committee meetings added in 2023.
III	Process Safety	Added Figure 12 which denotes how PG&E's Project Safety Management System is integrated with PG&E Safety Excellence Management System (PSEMS).
IV	Asset Management	Attachment 3 to this Plan contains 2023 change logs for each Asset Family's Asset Management Plan.
IV.2.a	Gas Storage	Added language regarding the 2023 GRC Decision (D.23-11-069) to continue operating the Los Medanos storage field.
IV.2.c	Transmission Pipe	Added language regarding the CPUC's Decision (D.23-12-003) approving PG&E's transmission definition change.
IV.2.f	Customer Connected Equipment	Updated Table 8 to reflect PG&E's goal to develop and incorporate DIMP specifications in the purchasing specification for the next generation of Smart Meters, including consideration of seismic shutoff capability.
IV.2.h	Data	Updated Table 11 to include the objective to develop and implement the data governance framework to improve underlying data quality.
IV.4	Records and Information Management	Updated Table 14 to include Information Governance Model Assessments.
IV.5.a	Damage Prevention	Revised Table 15 to reflect name change of the Gold Shovel Standard. The Gold Shovel Standard Program has evolved into the Damage Prevention Institute.
IV.5.a.iv	Standby Governance	Added new subsection regarding Standby Governance for excavations.
IV.5.h	Corrosion Control	Added language to acknowledge regulation changes as a result of the PHMSA Mega Rule Part 2 publishing.
IV.5.h	Corrosion Control	Added language to note PG&E's participation in the Association for Material Protection and Performance (AMPP) committee.
IV.5.j	Leak Survey	Highlighted that PG&E was able to conduct leak survey on over 1,000 locations that were previously inaccessible (Can't Get In - CGI).
IV.6.b	Inventory Management	Added a new subsection on PG&E's Inventory Management highlighting the inventory management process.
IV.6.e.ii	Company Emergency Response Plan	Attachment 3 to this Plan contains the Company Emergency Response Plan change log for 2023.
IV.6.e.iii	Gas Emergency Response Plan	Attachment 3 to this Plan contains the Gas Emergency Response Plan change log for 2023.
VI.4	Supportive Controls	Added Figure 65 depicting Compliance Supportive Controls.
VII.1.a	Electric and Gas Performance and Process Improvement Team (E&G PPI)	This section highlights the establishment of 15 Lean Model Standard Yards across the service territory.
VII.2	Quality Management	Updated Table 31 to include the Valve Maintenance program.

<u>VERIFICATION</u>

We, the undersigned, state:

We are officers of PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, and are authorized to make this verification for and on behalf of said corporation, and we make this verification for that reason. We have read the foregoing 2024 Gas Safety Plan, and are informed and believe the matters therein are true and, on that ground, we allege that the matters stated therein are true.

We 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 15, 2024.

Christine Cowsert
SENIOR VICE PRESIDENT
ENTERPRISE BUSINESS AND TECHNOLOGY MODERNIZATION
PACIFIC GAS AND ELECTRIC COMPANY

Joseph Forline
SENIOR VICE PRESIDENT
GAS OPERATIONS
PACIFIC GAS AND ELECTRIC COMPANY